PY 2021 PG&E AND SCE ELRP LOAD IMPACT EVALUATION REPORT

FINAL

Public Version.

Redactions to PY 2021 PG&E and SCE ELRP Load Impact Evaluation Report and Appendices--[redacted]*-- Confidential content removed and blacked out*

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1 EXECUTIVE SUMMARY

1.1 PROGRAM OVERVIEW AND EVALUATION OBJECTIVES

The Emergency Load Reduction Program (ELRP) represents two demand response (DR) pilots[1] for PG&E and Southern California Edison (SCE) authorized for five years, subject to revision, with the goal of allowing the IOUs and CAISO to access additional, emergency load reduction during times of high grid stress. The goal of the program is to help the IOUs and CAISO avoid outages while controlling costs to ratepayers. The Pilots provide payments based on the total energy reduction over the event period with no capacity payments.

The ELRP is available from May through October, seven days a week from 4:00 to 9:00 P.M. with a one-hour minimum and a five-hour maximum event duration. Participants can be dispatched using a day ahead or day of notification for a maximum of 60 hours with no restrictions on consecutive day dispatches. Eligible customers are broken into two distinct groups with multiple sub-groups. The 2021 ELRP groups are *Group A: Select non-residential customers and aggregators* (Group A) and *Group B: Market-integrated proxy demand resources (PDRs)* (Group B).

The objective of the Evaluation is to assess the PY 2021 ELRP in a manner that conforms to the Load Impact Protocols (LIP) adopted by the CPUC in Decision (D.) .08-04-050. The evaluation estimates ex post load impacts[2] for PY 2021 and forecasts ex ante impacts for the years 2022-2025.[3] The evaluation also includes analysis to assess the effects of COVID-19 on participant energy usage and, where necessary, applies adjustments to the ex ante forecasts.

1.2 PARTICIPANT AND EVENT INFORMATION

The 2021 ELRP is made up of 903 customers[4] that participated in events, 864 under PG&E and 39 under SCE. PG&E's population can be broken down into Group A.1 and Group A.2 participants with 774 and 90 participants in each group, respectively. The difference between PG&E and SCE program participation is largely driven by the types of participants targeted by the respective IOUs in 2021. PG&E, which had a

[1] SDG&E also has an ELRP program, but it is not included in this evaluation.

[2] This evaluation estimated load impacts of all enrolled customers. Ex post load impacts were performed irrespective of whether or not a customer received an ELRP incentive payment.

[3] The ELRP pilot ends at the end of 2025, unless extended.

[4] Defined as unique service agreements (PG&E) and customer contracts (SCE). PG&E participant counts are based on the maximum event day participant counts due to incomplete participant and enrollment information.

greater number of participants in 2021 compared to SCE, required a minimum of 1 kW in curtailable load for participation whereas SCE required a customer size of at least 200 kW. This difference in requirements not only led to the difference in participant counts, but because industry types are associated with certain customer sizes, it also resulted in differences in the types of participants across the IOUs. Table 1-1 below presents the shares of 2021 ELRP participants by North American Industry Classification System (NAICS) description for PG&E and SCE.

TABLE 1-1: ELRP PARTICIPANT COUNTS AND SHARES BY NAICS DESCRIPTION

	PG&E				SCE	
	Group A.1		Group A.2		Group A.1	
NAICS Description	**Count**	**Share**	**Count**	**Share**	**Count**	**Share**
Agriculture, Mining & Construction	442	57%	33	37%	10	26%
Institutional/Government	9	1%	0	0%	9	23%
Manufacturing	14	2%	21	23%	5	13%
Offices, Hotels, Finance, Services	159	21%	1	1%	2	5%
Retail Stores	10	1%	0	0%	2	5%
Schools	2	0%	0	0%	1	3%
Wholesale, Transport, Other Utilities	41	5%	21	23%	5	13%
Other	--	--	--	--	5	13%
Unknown	97	13%	14	16%	--	--
Total	**774**	**100%**	**90**	**100%**	**39**	**100%**

*Unknown PG&E participant counts are based on differences between provided participant information and the maximum event participant count in PY 2021.

There were four ELRP events during the 2021 event season in PG&E's service territory and three events in SCE's territory. All 2021 events were day-of Group A dispatches. For all events ELRP resources were fully dispatched, and all enrolled participants were called to curtail their loads. Table 1-2 presents the 2021 ELRP event dates, times, day of week, and number of participants in each event. It should be noted that July 9th was also a BIP event day with overlapping event hours.

TABLE 1-2: PY 2021 ELRP EVENTS

IOU	Dispatch Group*	Day of Week	ELRP Event Date	ELRP Event Time	Total Participants
PG&E	A.1 and A.2	Thursday	June 17th, 2021	19:00-21:00	116
		Friday	July 9th, 2021	17:00-21:00	717
		Saturday	July 10th, 2021	17:00-21:00	717
		Thursday	July 29th, 2021	18:00-21:00	864
SCE	A.1	Friday	July 9th, 2021	17:00-21:00	34
		Saturday	July 10th, 2021	17:00-21:00	34
		Thursday	July 29th, 2021	18:00-21:00	39

*A.2 participants and A.1 BIP dually-enrolled participants only receive compensation for overlapping BIP event hours.

1.3 METHODOLOGY

1.3.1 Ex Post Methodology

The ex post analysis relies on a combination of customer-specific regression models and panel models with matched control groups to estimate baseline load and event day hourly impacts. It should be noted that matched control groups were only explored for specific PG&E ELRP participant customer segments. SCE ex post impacts rely solely on customer-specific models due to smaller participant counts and a high degree of variability in participant load shapes.

Customer-specific regression models were selected and used to estimate impacts for all participants, regardless of whether they were included in panel modeling. Panel models and their associated impacts are included in the total population, industry, and customer size segments for A.1 customers. All other segments rely exclusively on customer-specific regression models. PG&E Group A.2 customers only had one participant fall into these categories, as a result panel models were not suited for A.2 impact estimation and relied solely on individual regression models.

1.3.2 Ex Ante Methodology

The goal of the ex ante impact analysis is to estimate program impacts into future years under varying 1-in-10 and 1-in-2 weather scenarios[5] across the ELRP event window (4:00 pm to 9:00 pm). Given that the ELRP is a pilot program, the ex ante analysis seeks to provide ex ante estimates for program years 2022

[5] The 1-in-2 and 1-in-10 weather scenarios include a typical event day, monthly IOU system peak and monthly IOU CAISO system peak and vary for PG&E and SCE.

through 2025. Additionally, the ex ante analysis was conducted using two approaches. These include "top-down" and "bottom-up" approaches.

It should first be noted that ex ante analysis only seeks to estimate impacts for Group A.1 participants for both PG&E and SCE. The primary reason is that there was no event participation for Groups A.3, A.4, B.1 and B.2[6] for both IOUs and no participation in Group A.2 for SCE. As a result, there are no ex post impacts to inform an LIP based ex ante analysis. Additionally, it was decided to not produce ex ante impacts for PG&E A.2 because there are virtually no impacts associated with the A.2 customers (discussed in Section 4). In essence, there is no active Group A.2 program activity to inform weather adjusted impacts or ex ante forecasts.

1.4 EXPOST IMPACTS

The average event hour impacts for each PG&E and SCE event and the average event day are presented in Table 1-3 and Table 1-4 respectively.

TABLE 1-3: PG&E 2021 ELRP AVERAGE EVENT HOUR IMPACTS BY GROUP

Group	Event Date	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Service Point Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
Group A.1	June 17th	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	July 9th	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	July 10th	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	July 29th	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Avg. Event	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Group A.2	June 17th	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	July 9th	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	July 10th	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	July 29th	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Avg. Event	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[6] PG&E had CBP aggregators and DRPs enrolled in in the ELRP, however, no group B events called for PY 2021.

TABLE 1-4: SCE 2021 ELRP AVERAGE EVENT HOUR IMPACTS BY GROUP

Group	Event Date	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Service Point Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
Group A.1	July 9th	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	July 10th	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	July 29th	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Avg. Event	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

On the average event day, PG&E A.1 participants provided an average of [redacted] MW of load reduction in each ELRP event hour. The largest load reductions, on average, occurred on July 10th, with an average hourly load reduction of [redacted] MW (or 7.1% of the estimate baseline).

PG&E Group A.2 participants provided negligible load reductions during 2021. While Group PG&E A.2 participants were dispatched for the BIP event on July 9th, there were no obvious indicators of significant curtailment associated with ELRP participation. On average, Group PG&E A.2 participants reduced their load by 0.7% on the average event day.

While A.2 participants were not compensated for participation on non-BIP ELRP event days, BIP aggregators could in theory voluntarily participate given they were notified for events. However, there is no evidence that A.2 participants responded to events on non-BIP ELRP event days given the negative and small average percent load reductions (-6.8% to 2.1%) and event day load shapes presented in Appendix D.

SCE ELRP did not see load reductions, on average, for any event during the 2021 event season. The average hourly event day impact for the 2021 ELRP was [redacted] MW (an increase in load). This load increase is primarily driven by the two largest ELRP participants either not curtailing during event hours, delayed snapback from prior days of participation in BIP, or dispatching at the incorrect time (discussed in Section 4.2.2).

1.4.1 Average Event Day Load Shapes

Visually representing event day load shapes and estimated baselines is a powerful tool for understanding event day activity and for framing impact estimates. Figure 1-1 and Figure 1-2 show the average event day load profiles for PG&E Group A.1 and Group A.2 participants. Given that events occurred on varying hours across event days, the density of the shaded areas relates to the frequency of event days where a given hour was an event hour. The opaquer the shading on an event hour, the more frequently that hour was an event hour. Appendix B presents the load shapes for each event day for PG&E Group A.1 and Group A.2.

The average event day for PG&E A.2 participants is the same as the July 9th event day. While there are a small number of BIP participants enrolled through the A.1 pathway, A.2 participants exclusively represent BIP aggregators. As a result, all A.2 load reductions are attributed to BIP in hours ending 19 through 21 on the average event day.

FIGURE 1-1: PG&E AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – GROUP A.1

[redacted]

FIGURE 1-2: PG&E AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – GROUP A.2

[redacted]

Figure 1-3 presents the average event day for SCE PG&E group A.1 As with PG&E, events occurred on varying hours across event days, the density of the shaded areas relates to the frequency of event days where a given hour was an event hour. The opaquer the shading on an event hour, the more frequently that hour was an event hour. Appendix B presents the load shapes for each SCE A.1 event day.

FIGURE 1-3: SCE AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – GROUP A.1

[redacted]

1.5 EX ANTE IMPACTS

Ex Ante impacts were estimated under two scenarios. These included the Load Impact Protocols (LIP) compliant bottom-up analysis and the participant nomination driven top-down analysis. Table 1-5 and Table 1-6 present the average event hour ex ante impacts for 2022 under typical event day weather conditions. PG&E forecasts 117 MW of available curtailment and 1,582 participants in 2022, with no expected growth for A.1 participation through the life of the ELRP pilot. SCE is forecasting 54.9 MW of available curtailment and 211 participants for 2022 with roughly 15% growth year over year. As a result, the PY 2022 top-down ex ante forecast for PG&E is 117 MW and 54.9 MW for SCE. Alternatively, the PY 2022 bottom-up ex ante 1-in-10 and 1-in-2 MW estimates are 19.6 MW and 16.9 MW, respectively, for PG&E and 7.7 MW and 6.9 MW for SCE.

TABLE 1-5: PG&E EX ANTE AVERAGE EVENT HOUR IMPACTS - TYPICAL EVENT DAY

Analysis	Utility Weather Year	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Customer Impact (kWh/h)	Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
PY 2022 Ex Ante - Bottom-Up	1-in-10	1,582	171.3	12.4	7.2%	19.6	96.2
	1-in-2	1,582	168.1	10.7	6.4%	16.9	93.5
PY 2022 Ex Ante -Top-Down	1-in-10	1,582	171.3	74.0	43.1%	117.0	96.2
	1-in-2	1,582	168.1	74.0	44.0%	117.0	93.5

TABLE 1-6: PG&E EX ANTE AVERAGE EVENT HOUR IMPACTS - TYPICAL EVENT DAY

Analysis	Weather Year	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Customer Impact (kWh/h)	Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
PY 2022 Ex Ante - Bottom-Up	1-in-10	211	892.9	36.7	4.1%	7.7	93.7
	1-in-2	211	880.8	32.9	3.7%	6.9	86.0
PY 2022 Ex Ante -Top-Down	1-in-10	211	892.9	260	29.1%	54.9	93.7
	1-in-2	211	880.8	260	29.5%	54.9	86.0

Figure 1-4 and Figure 1-5 present the bottom-up and top-down MW ex ante impacts for PG&E and SCE from through the life of the pilot (PY 2022 through PY2025).

FIGURE 1-4: PG&E GROUP A.1 BOTTOM-UP AND TOP-DOWN EX ANTE IMPACT ESIMATES – PY 2022 TO PY 2025

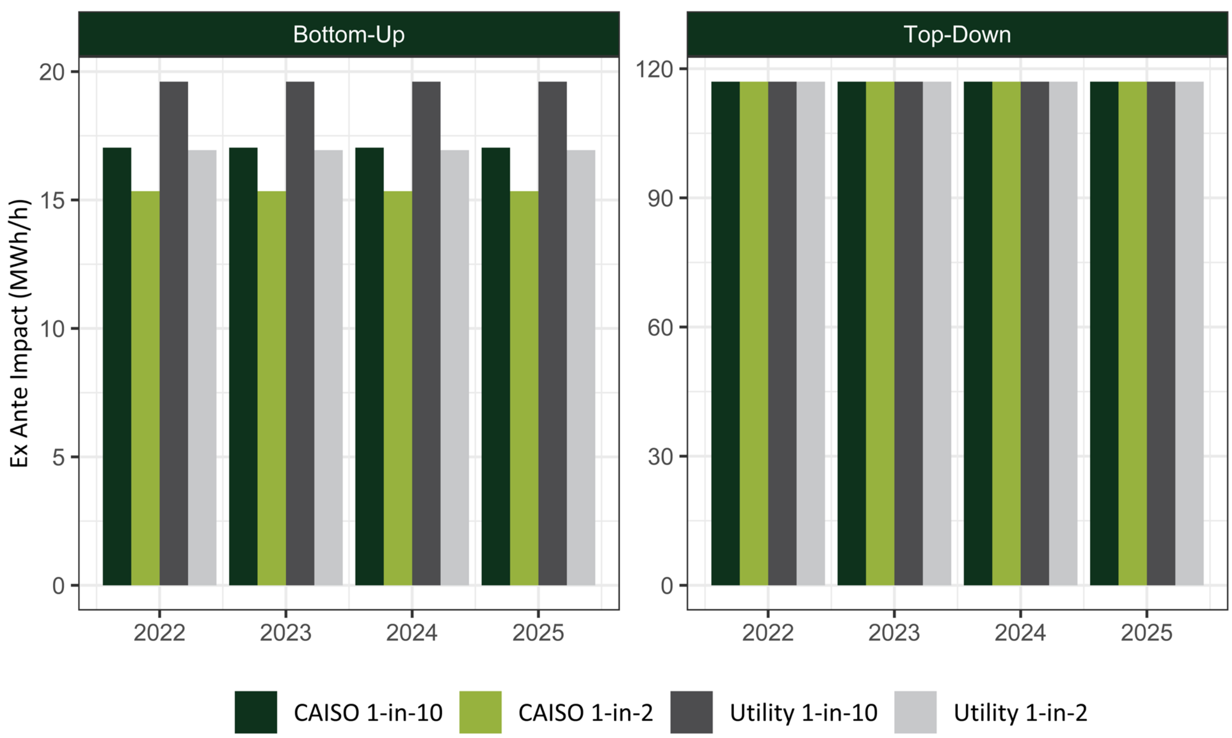
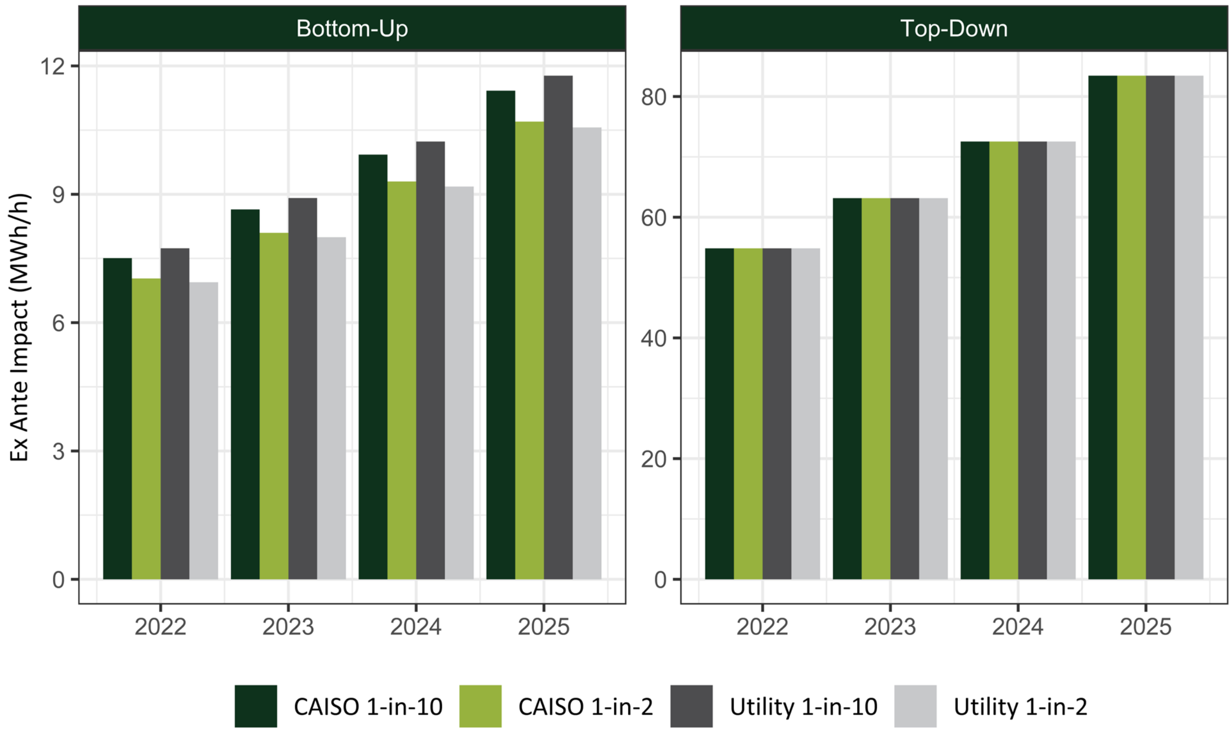


FIGURE 1-5: SCE GROUP A.1 BOTTOM-UP AND TOP-DOWN EX ANTE IMPACT ESIMATES – PY 2022 TO PY 2025



2 INTRODUCTION

2.1 PROGRAM OVERVIEW

The Emergency Load Reduction Program (ELRP) represents two demand response (DR) pilots[7] for PG&E and Southern California Edison (SCE) authorized for five years, subject to revision, with the goal of allowing the IOUs and CAISO to access additional, emergency load reduction during times of high grid stress. The goal of the program is to help the IOUs and CAISO avoid outages while controlling costs to ratepayers. The Pilots provide payments based on the total energy reduction over the event period with no capacity payments.

The ELRP is available from May to October, seven days a week from 4:00 to 9:00 P.M. with a one-hour minimum and a five-hour maximum event duration. Participants can be dispatched using a day ahead or day of notification for a maximum of 60 hours with no restrictions on consecutive day dispatches. Eligible customers are broken into two distinct groups with multiple sub-groups. The 2021 ELRP groups are *Group A: Select non-residential customers and aggregators* (Group A) and *Group B: Market-integrated proxy demand resources (PDRs)* (Group B). Group A and Group B can be broken down into additional subgroups. The 2021 ELRP subgroupings included:

Group A: Select Non-Residential Customers and Aggregators

- A.1. Non-Residential Customers (dual participation with BIP and AP-I allowed)
- A.2. BIP Aggregators
- A.3. Rule 21 Exporting Distributed Energy Resources (DER)
- A.4. Virtual Power Plant (VPP) Aggregators

Group B: Market-Integrated PDR Resources

- B.1. Third-party DR Providers
- B.2. IOU Capacity Bidding Program (CBP) Aggregators

Despite the availability of six subgroups to customers, the 2021 ELRP only saw participation in subgroups A.1 and A.2 for PG&E and only A.1 for SCE. It should be noted that the ELRP offered $1 per kWh in load reduction and there is no penalty associated with missing nominated load reduction bids as long as the

[7] SDG&E also has an ELRP program, but it is not included in this evaluation.

demonstrated load reduction was at least 50% and not over 200% of the customers' nominated bid amount. Additionally, BIP participants are only incentivized with curtailments that go beyond their Firm Service Level (FSL) commitments during overlapping BIP and ELRP events hours. However, dually enrolled A.1 BIP participants and A.2 BIP aggregators are notified for each ELRP events. For SCE, BIP customers dually enrolled in ELRP were not incentivized in 2021.

Additionally, several changes were made to the program that take effect for the 2022 event season. The most relevant changes to the program for this evaluation report is the increase in incentives from $1 per kWh to $2 per kWh and reducing the size requirement for SCE participants from 100 kW to 200 kW. All other program changes are not discussed in this report.

2.2 EVALUATION OBJECTIVES

The objective of the Evaluation is to assess the PY 2021 ELRP in a manner that conforms to the Load Impact Protocols (LIP) adopted by the CPUC in Decision D.08-04-050. The evaluation estimates ex post load impacts[8] for PY 2021 and forecasts ex ante impacts for the years 2022-2025.[9] The evaluation also includes analysis to assess the effects of COVID-19 on participant energy usage and, where necessary, applies adjustments to the ex ante forecasts.

2.3 PARTICIPANT CHARACTERISTICS

The 2021 ELRP is made up of 903 customers[10] that participated in events, 864 under PG&E and 39 under SCE. PG&E's population can be broken down into Group A.1 and Group A.2 participants with 774 and 90 participants in each group respectively. The difference between PG&E and SCE program participation is largely driven by the types of participants targeted by the respective IOUs in 2021. PG&E, which had a greater number of participants in 2021 compared to SCE, required a minimum of 1 kW in curtailable load for participation whereas SCE required a customer size of at least 200 kW. This difference in requirements not only led to the difference in participant counts, but because industry types are associated with certain customer sizes, it also resulted in differences in the types of participants across the IOUs. Table 2-1 below presents the shares of 2021 ELRP participants by North American Industry Classification System (NAICS) description for PG&E and SCE. The largest customer segments for PG&E are "Agriculture, Mining & Construction" and "Offices, Hotels, Finance, Services," which account for 74% of 2021 participants

[8] This evaluation estimated load impacts of all enrolled customers. Ex post load impacts were performed irrespective of whether or not a customer received an ELRP incentive payment.

[9] The ELRP pilot ends after 2025, unless extended.

[10] Defined as unique service agreements (PG&E) and customer contracts (SCE). PG&E participant counts are based on the maximum event day participant counts due to incomplete participant and enrollment information.

between Group A.1 and A.2. For SCE, the largest customer segments are “Institutional/Government” and “Agriculture, Mining & Construction”, representing more than half of SCE’s participants.

TABLE 2-1: ELRP PARTICIPANT COUNTS AND SHARES BY NAICS DESCRIPTION

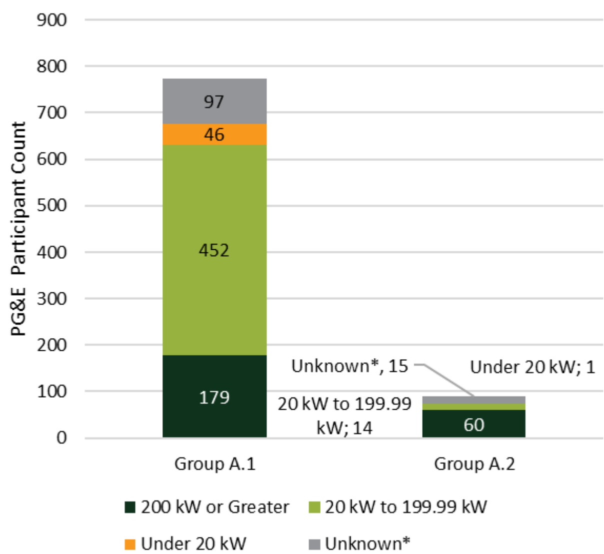
	PG&E				SCE	
	Group A.1		Group A.2		Group A.1	
NAICS Description	Count	Share	Count	Share	Count	Share
Agriculture, Mining & Construction	442	57%	33	37%	10	26%
Institutional/Government	9	1%	0	0%	9	23%
Manufacturing	14	2%	21	23%	5	13%
Offices, Hotels, Finance, Services	159	21%	1	1%	2	5%
Retail Stores	10	1%	0	0%	2	5%
Schools	2	0%	0	0%	1	3%
Wholesale, Transport, Other Utilities	41	5%	21	23%	5	13%
Other	--	--	--	--	5	13%
Unknown	97	13%	14	16%	--	--
Total	**774**	**100%**	**90**	**100%**	**39**	**100%**

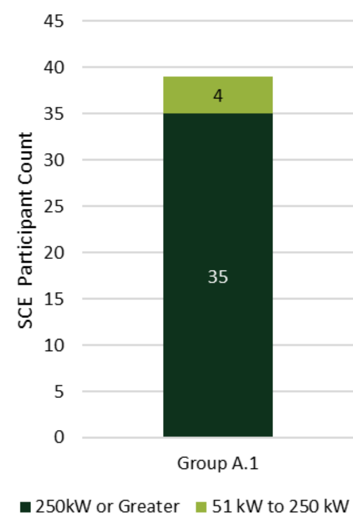
*Unknown PG&E participant counts are based on differences between provided participant information and the maximum event participant count in PY 2021.

Figure 2-1 shows the counts and relative distributions of 2021 ELRP participants by customer size[11] for each utility. As mentioned above, PG&E and SCE targeted different customer types for the ELRP. This directly resulted in differing customer sizes of participants between PG&E and SCE. Most of SCE’s participants were of sizes 250 kW or greater, while the majority of PG&E customers were between 20 kW to 199.9 kW. However, the majority PG&E Group A.2 participants were in the 200 kW or greater category.

[11] Customer size as designated by PG&E and SCE. Customer size refers the magnitude of the participant’s peak load.

FIGURE 2-1: PG&E (LEFT) AND SCE (RIGHT) PARTICIPANT COUNTS BY CUSTOMER SIZE AND GROUP

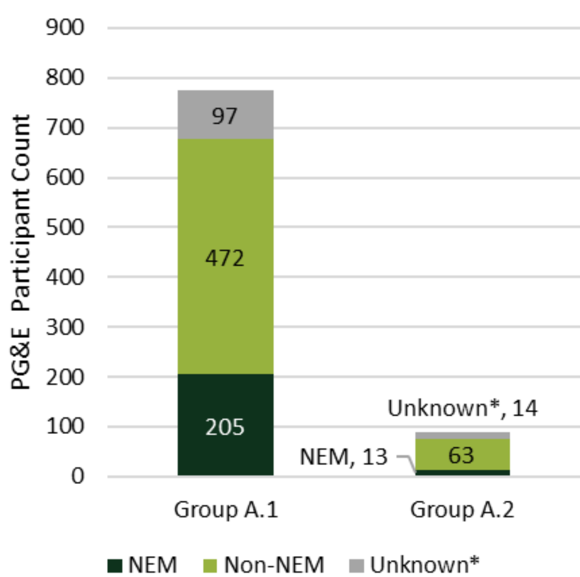


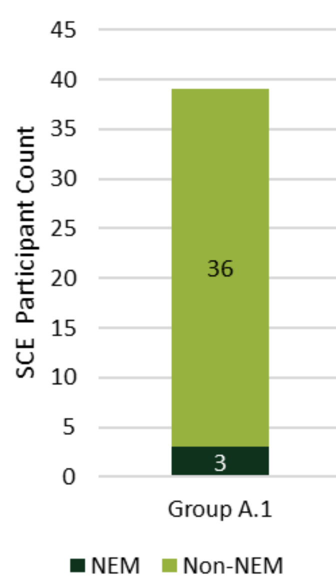


*Unknown PG&E participant counts are based on differences between provided participant information and the maximum event participant count in PY 2021.

Figure 2-2 below shows the counts and relative distributions of 2021 ELRP participants by NEM status. As seen, PG&E had 218 customers with NEM (205 in Group A.1 and 13 in Group A.2) while SCE had three.

FIGURE 2-2: PG&E (LEFT) AND SCE (RIGHT) PARTICIPANT COUNTS BY NEM STATUS AND GROUP

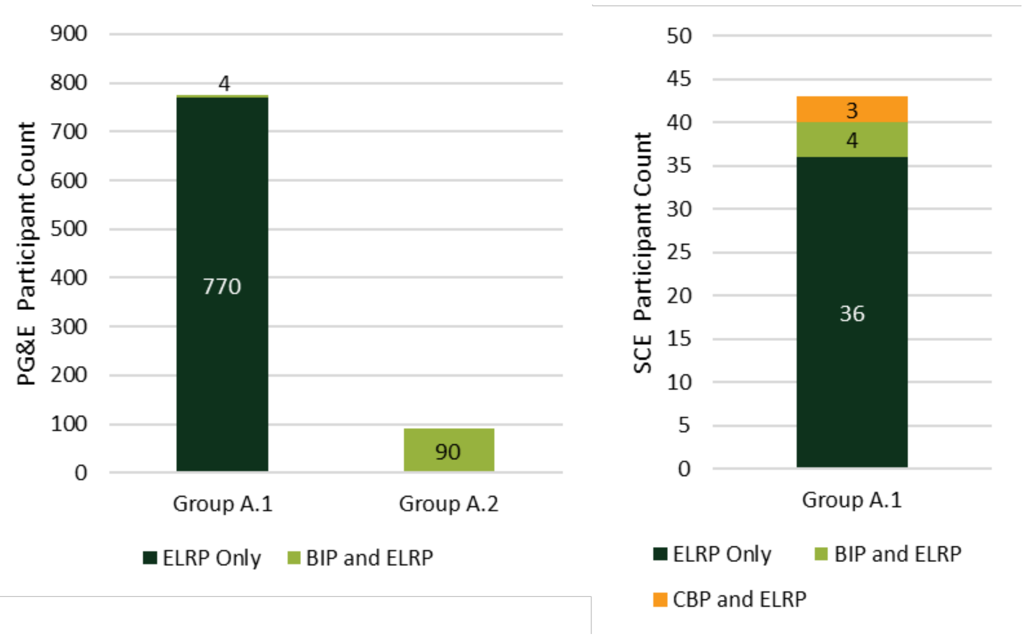




*Unknown PG&E participant counts are based on differences between provided participant information and the maximum event participant count in PY 2021.

Figure 2-3 shows the counts and relative distributions of 2021 ELRP participants by dual enrollment status. Dual enrollment is defined as a participant being enrolled in the ELRP and another demand response program. The primary program of dual enrollment for the ELRP is enrollment in the Base Interruptible Program (BIP), however SCE also had three participants that were also enrolled in the Capacity Bidding Program (CBP).[12] All A.2 participants were dually enrolled as this participation pathway is open for BIP aggregators. However, BIP participants may also enroll into the ELRP individually under A.1. As a result, both the SCE and PG&E had four dually enrolled BIP participants enrolled through the A.1 pathway.[13] Dual enrollment is an important feature of the ELRP that had significant implications for the evaluation (discussed further in section 3.3.6).

FIGURE 2-3: PG&E (LEFT) AND SCE (RIGHT) PARTICIPANT COUNTS BY DUAL ENROLLMENT STATUS AND GROUP



Note: PG&E total participant counts are based the maximum event participant count in PY 2021.

12 Customers on CBP were allowed to participate in Group A as long as they were not nominated by their CBP Aggregator. Customers were required to provide a nomination bid amount upon enrollment.

13 Per CPUC Decision (D.) 21-03-056, dual participation with ELRP and BIP was deferred for PY2021. Some BIP participants requested to enroll in ELRP even though they would not be eligible for ELRP compensation in 2021.

2.4 EVENT INFORMATION

There were four ELRP events during the 2021 event season in PG&E's service territory and three events in SCE's territory. All 2021 events were day-of Group A dispatches. ELRP resources were fully dispatched for all events and all enrolled participants were notified to curtail their loads. Table 2-2 presents the 2021 ELRP event dates, times, day of week, and number of participants in each event. It should be noted that July 9th was also a BIP event day with overlapping event hours.

TABLE 2-2: PY 2021 ELRP EVENTS

IOU	Dispatch Group*	Day of Week	ELRP Event Date	ELRP Event Time	Total Participants
PG&E	A.1 and A.2	Thursday	June 17th, 2021	19:00-21:00	116
		Friday	July 9th, 2021	17:00-21:00	717
		Saturday	July 10th, 2021	17:00-21:00	717
		Thursday	July 29th, 2021	18:00-21:00	864
SCE	A.1	Friday	July 9th, 2021	17:00-21:00	34
		Saturday	July 10th, 2021	17:00-21:00	34
		Thursday	July 29th, 2021	18:00-21:00	39

*A.2 participants and A.1 BIP dully-enrolled participants only receive compensation for during dual BIP event hours.

BIP participation greatly influences the ELRP program design[14] and therefore the evaluation of ELRP. For this reason, Table 2-3 presents the July 9th overlapping BIP event day event information.

TABLE 2-3: PY 2021 OVERLAPPING BIP EVENT DAY INFORMATION

IOU	BIP Event Date	BIP Event Time	ELRP Group A.1 Participants	ELRP Group A.2 Participants
PG&E	July 9th, 2021	18:30-20:30	4	90
SCE	July 9th, 2021	17:50-20:56	4	--

2.5 REPORT ORGANIZATION

The remaining sections of this report are organized as follows:

- **Section 3 Data and Methods.** This section presents the data and methods used for the PY 2021 evaluation of the ELRP.

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[14] While BIP dually enrolled BIP participants are notified for all ELRP events, they are only compensated for load reductions during overlapping event hours. SCE dually enrolled BIP participants were not compensated for ELRP participation in PY 2021.

- **Section 4 Ex Post Results.** This section presents the ex post analysis results from PY 2021 ELRP participation and supporting analysis.
- **Section 5 Ex Ante Results.** This section presents forecasts of the ELRP ex ante impacts for PY 2021 through PY2025.
- **Section 6 Comparison Between Ex Post and Ex Ante.** This section discusses the difference between the ex post and ex ante impacts, as well as why they are different.
- **Section 7 Findings and Recommendations.** This section presents the findings and recommendations for the ex post and ex ante impact analysis.
- **Appendices A through D.** These appendices present the ex post and ex ante table generators and various analyses that support the ex post and ex ante methodology and results

3 DATA AND METHODS

This section presents the data sources and evaluation methodology used for this PY 2021 ex post and ex ante impact analysis.

3.1 DATA SOURCES

The data sources that are required for the 2021 ELRP evaluation include:

- Participant information and characteristics
- ELRP event information
- Non-ELRP event information for programs associated with dually enrolled participants
- AMI (Advanced Metering Infrastructure) interval data for participants and non-participants
- Participant and non-participant SMB (small-to-medium business) billing data
- Historical hourly weather data
- Historical hourly irradiance data
- Ex ante weather scenarios
- Participant enrollment forecasts

Data Collection

Verdant worked with PG&E and SCE to obtain the necessary data to estimate the ex post impacts and forecast ex ante load reductions for the ELRP. The data required for ex post and ex ante analyses of the ELRP include the following items.

Customer Information and AMI data. Verdant requested customer information and service point level AMI data for customers enrolled in the ELRP. Given the desire to use a control group, as well as conduct analysis to account for COVID-19 impacts, Verdant requested AMI data for participant and non-participant service points. The requested customer information included those necessary to segment the data by the domains of interest (e.g., sector, industry, etc.) as well as information to map to any weather stations. To meet the needs of all the research activities, AMI data from three years were requested. The AMI data for each ELRP participant was requested from May through October for 2019, 2020, and 2021.

Customer Billing Data. Verdant requested participant billing data and a random sample of non-participant billing data to use for selection of matched control groups.[15] Billing data was requested for three years prior to the participant's first year of enrollment.

Program information. Verdant requested information on customer program participation, the date customers enrolled in the ELRP and other relevant DR programs and the timing of disenrollment if the customer left the ELRP or other DR programs. Verdant requested information from PG&E and SCE on the timing and duration of ELRP events.

Other DR participation. The evaluation required accounting for participation in other utility DR programs. Verdant requested enrollment dates and de-enrollment dates for other program participation for dually enrolled ELRP participants and the event times and durations for those events

Weather and irradiance data. PG&E and SCE provided the weather data that is necessary to model weather sensitive loads as well as irradiance data to be used for participants with on-site solar generation.

Participant forecasts. The ex ante forecasts rely on a projection of participation over the forecast horizon. PG&E and SCE provided these data. Participant and MW forecasts were provided by PG&E and SCE.

Weather scenarios. The ex ante forecasts also rely on data to reflect the different weather scenarios in the different climate zones under different conditions (e.g., 1-in-2 and 1-in-10 weather years, typical event day, system peak, etc.). Separate versions of data were provided by both the utilities and CAISO, though they are typically very similar.

3.2 PG&E PARTICIPANT DATA ATTRITION

The evaluation of the PY 2021 ELRP attempted to include all PY 2021 participants into the estimation of ex post and ex ante impacts. However, not all of PG&E's PY 2021 participant population was included into the evaluation due to missing participant characteristic, enrollment and event participation information resulting from misalignments in anonymized service agreement identifiers used by PG&E and the implementation team. Table 3-1 below presents the data attrition by event date and group.

[15] Matched control groups were only used for PG&E participants. SCE's participant population size and characteristics did not lend itself to panel modeling.

TABLE 3-1: PG&E DATA ATTRITION BY EVENT DAY AND GROUP

Group	ELRP Event Date	Total Participants	Participants Included	Participants NOT Included	Share of Participants Included
A.1	June 17th, 2021	30	16	14	53%
	July 9th, 2021	627	562	65	90%
	July 10th, 2021	627	562	65	90%
	July 29th, 2021	770	678	96	88%
A.2	June 17th, 2021	86	72	14	84%
	July 9th, 2021	90	75	15	83%
	July 10th, 2021	90	75	15	83%
	July 29th, 2021	90	75	15	83%

3.3 EX POST IMPACT METHODOLOGY

The ex post impact methodology is designed to achieve the goal of the ex post analysis. The goals for the ex post impact analysis include:

- Estimating the aggregate and per-customer hourly load impacts and average daily load impacts for each event in PY 2021 and an average event day;
- Estimating the distribution of aggregate and per-customer load impacts for non-residential customers for the average event by ELRP participant group, industry type, customer size, customer type, NEM Status, and dually enrolled status;
- And calculation of confidence intervals surrounding impact estimates for each hour, as well as the average event hour.

The ex post analysis relies on a combination of customer-specific regression models and panel models with matched control groups to estimate baseline load and event day hourly impacts. It should be noted that matched control groups were only explored for specific PG&E ELRP participant customer segments. SCE ex post impacts rely solely on customer-specific models due to smaller participant counts and a high degree of variability in participant load shapes.

Customer-specific regression models were selected and used to estimate impacts for all participants, regardless of whether they were included in panel modeling. Panel models and their associated impacts are included in the total population, industry, and customer size segments for A.1 customers. All other segments rely exclusively on customer-specific regression models. PG&E Group A.2 customers only had one participant fall into these categories, as a result panel models were not suited for A.2 impact estimation and rely solely on individual regression models. Details on matched control group, model selection and proxy day testing, and impact specifications are presented in the following subsections.

It should be noted that PG&E reference loads and impacts were modeled at the service point level and were then aggregated to the participant (service agreement) level. As a result, participant counts referring to modeling and modeling metrics represent counts of service points rather than individual PG&E ELRP participants. The AMI data provided by SCE was already at the participant (contract) level, as a result SCE modeling occurred at the participant level.

3.3.1 Matched Control Group Development

In general, the estimation of demand response impacts benefits from quasi-experimental design approaches that incorporate a control group (non-participants with similar characteristics to the participants) in the statistical modeling. By allowing the model to implicitly control for factors that may influence impacts but also affect other utility customers regardless of their program participation (for example, a rapid decrease in temperature or a call for all utility customers to reduce their electricity consumption in an emergency), the inclusion of such a group helps to estimate the effects from events more precisely. Given the benefits of this approach, Verdant conducted an analysis to identify suitable control groups for as many of the customer segments as possible. These segments were based on the industry type, size classification, and NEM status. The number of participants and available non-participant candidates for these segments is presented in Table 3-2.

TABLE 3-2: PG&E ELRP PARTICIPANT AND CONTROL GROUP CANDIDATE COUNTS BY SEGMENT

NAICS Description	Customer Size	NEM Status	Participant Service Points	Control Candidates
Agriculture, Mining & Construction	Under 20 kW	No	23	347
	20 kW to 199.99 kW	No	245	4,606
		Yes	165	2,651
	200 kW or Greater	No	94	1,651
		Yes	25	117
Institutional/Government	20 kW to 199.99 kW	No	22	99
Manufacturing	20 kW to 199.99 kW	No	13	140
	200 kW or Greater	No	42	557
Offices, Hotels, Finance, Services	Under 20 kW	No	24	393
	20 kW to 199.99 kW	No	164	1,144
		Yes	4	37
	200 kW or Greater	No	120	1,874
		Yes	18	183
Retail Stores	20 kW to 199.99 kW	No	18	364
	200 kW or Greater	No	8	118
Wholesale, Transport, Other Utilities	Under 20 kW	No	13	278
	20 kW to 199.99 kW	No	26	199
	200 kW or Greater	No	29	512

The identification of control groups relied on a stratified propensity score matching (SPSM) with replacement[16] to identify unbiased groups of non-ELRP DR customers or non-DR customers if not enough non-ELRP DR customers are available. The SPSM is based on a logistic regression model that predicts participation as a function of various load characteristics. The objective is to find a control group with similar load profiles to the ELRP customers, so all the attributes used as independent variables were derived from interval data. In preparation for the SPSM modeling, the following metrics were calculated using all non-event weekday data from the summer of 2021 for each account in the participant and non-participant pools:

- Average Daily kWh
- Coefficient of Variation on Hourly kWh
- Correlation of Hourly kWh-CDH

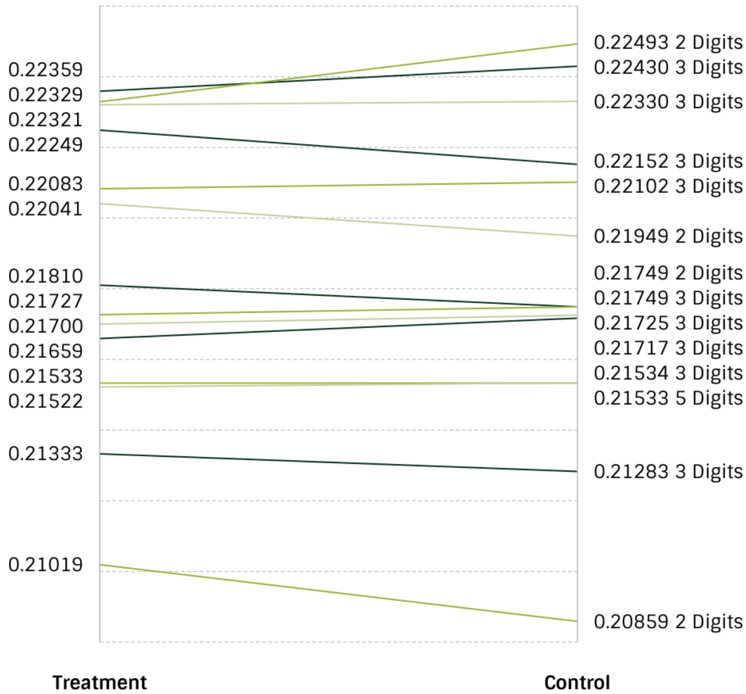
[16] SPSM with replacement allows a given control customer to serve as a matched control for multiple participant ELRP customers.

- Afternoon/Evening Correlation of Hourly kWh-CDH
- Average Daily Minimum kWh
- Average Daily Maximum kWh
- Standard Deviation of Daily Total kWh

Using the above as the independent variables, Verdant estimated a logit for each of the industry, size, and NEM status strata where ELRP participation was the binary dependent variable. The result of these models is a propensity score (ranging from 0 to 1) for each account that represents the likelihood that the account would be predicted to participate in the program. Both participant and control accounts have a propensity score, so the next step is to find a non-participant for each participant that has a similar score.

The level of precision in this process matters because it is unlikely, particularly in models with many continuous independent variables, that any two accounts will generate the exact same propensity score. For example, a participant with a rounded propensity score of 0.22041 might not have a match at five digits of precision, so a match needs to be found with fewer digits. For this reason, the process is done iteratively, starting with six digits of precision, and then lowering the level of precision required for matching each time until a match is found for each participant. An example of this is presented in Figure 3-1, which shows the propensity scores for the participants and the matched control accounts along with the digits or precision used to find a match. In this example, the participant with the propensity score of 0.22041 did not find a match until the precision was lowered to two digits, finally aligning with a control group account with a score of 0.2149.

FIGURE 3-1: PROPENSITY SCORE MATCHING EXAMPLE



After this process of selecting the control group accounts, the next step is to validate that the matching process resulted in a good control group. Verdant applied three different screens for this validation, beginning with a review of the matching results to ensure that the accounts were matched with a good level of precision. The more precision applied in finding a match, the more similar the paired control account should be. A control group where all or most of the matches were based on one digit of precision, for example, is less likely to resemble the participants. For this reason, Verdant tracked the level of precision used during the process to ensure that most of the matches were based on at least two digits of precision.

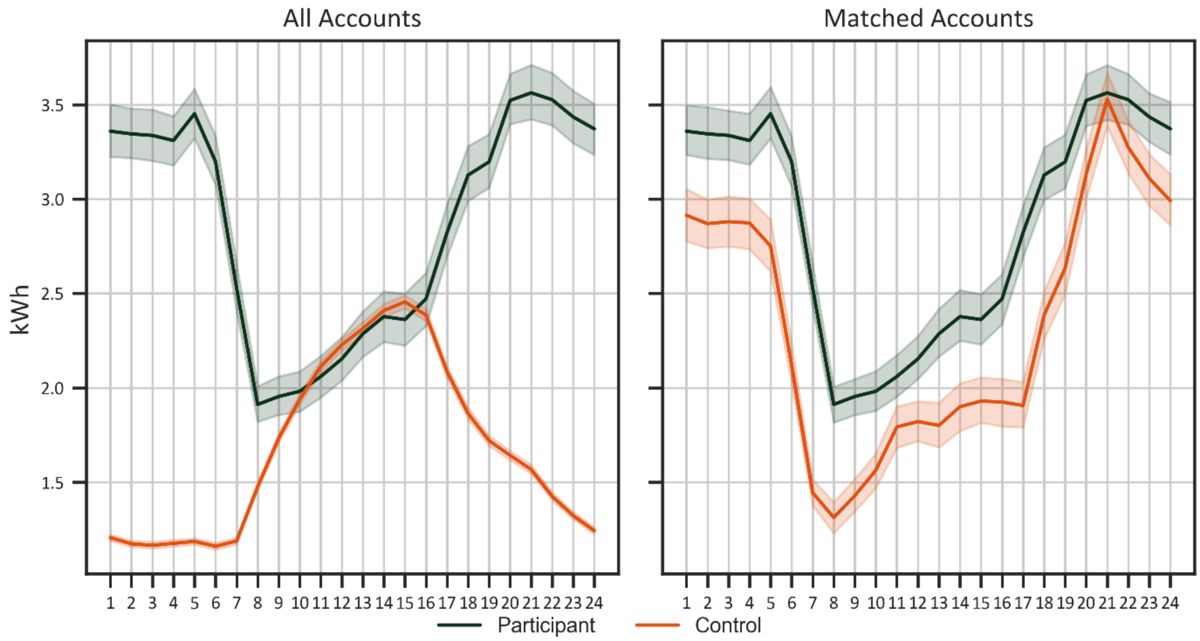
The second control group validation was based on independent sample t-tests for the logit model's independent variables where the participant was compared, first, to the full set of candidate control group accounts, and then with just those accounts that were matched to a participant. If the t-tests for the different metrics are not significantly different after selection of the control group, then the control group should be a good match. If there are still metrics with significant differences, then the matching did not produce a sufficiently similar control group for the segment. An example of this type of match validation is shown in Table 3-3, which shows the t-test results for one of the segments included in the analysis. In this example, five of the independent variables were different when comparing the participants to the full set of control candidates. After matching and selecting the best matches, the t-tests for all seven independent variables were not significant, suggesting that the SPSM successfully found a group of non-participants with characteristics similar to the participants.

TABLE 3-3: T-TESTS FOR PG&E OFFICES, HOTELS, FINANCE, SERVICES - UNDER 20 KW - NON-NEM

Variable	Service Points Compared	T-Test Statistic	p-value	Significant
Average Daily kWh	All	2.950	0.003	TRUE
	Matched	**0.780**	**0.439**	**FALSE**
Coefficient of Variation on Hourly kWh	All	-0.970	0.333	FALSE
	Matched	**0.311**	**0.757**	**FALSE**
Correlation of Hourly kWh-CDH	All	-4.728	0.000	TRUE
	Matched	**0.099**	**0.921**	**FALSE**
Afternoon/Evening Correlation of Hourly kWh-CDH	All	-4.277	0.000	TRUE
	Matched	**-0.667**	**0.508**	**FALSE**
Average Daily Minimum kWh	All	3.005	0.003	TRUE
	Matched	**1.501**	**0.140**	**FALSE**
Average Daily Maximum kWh	All	2.032	0.043	TRUE
	Matched	**1.722**	**0.092**	**FALSE**
Standard Deviation of Daily Total kWh	All	-0.448	0.654	FALSE
	Matched	**1.658**	**0.104**	**FALSE**

The final phase of validation is a more subjective visual evaluation of the results where the load profiles for the treatment group are compared with the full set of control group candidates and the final matched group. An example of this is shown in Figure 3-2, which shows the average hourly profiles for the same "Offices, Hotels, Finance, Services" segment used for the t-test results. On the left side of the graph, where the participants are shown with the full set of control candidates, the load profiles are clearly not equivalent, with the participants showing what is likely a time-of-use rate pattern of consumption. In contrast, the average profile of all the control group candidates has the profile of a more typical occupancy schedule. As the right side of the figure shows, however, after matching the load profiles are far more similar, and while they are not perfectly aligned, the matched accounts are much more defensible as a control group.

FIGURE 3-2: LOAD PROFILE VALIDATION FOR SPSM CONTROL GROUP



Developing control groups for non-residential customers can be difficult. The volatility of load in some segments and the lack of sufficient control group candidates means that in many cases there is not any group of accounts that will share the energy consumption attributes of participants. After completing modeling and validation for the 18 segments shown in Table 3-2: PG&E, Verdant determined that there were adequate control groups for five segments:

- Offices, Hotels, Finance, Services – Under 20 kW
- Offices, Hotels, Finance, Services – 20 kW to 199 kW
- Offices, Hotels, Finance, Services – 200 kW or Greater
- Retail Stores – 20 kW to 199 kW
- Wholesale, Transport, Other Utilities – 200 kW or Greater

As previously mentioned, matched control groups were only explored for PG&E, as SCE's participant population did not lend itself to quasi experimental design.

3.3.2 Weather Sensitivity

As described above, ELRP participants make up a wide variety of non-residential customers. The loads of non-residential customers are frequently found to have no relationship to outdoor air temperatures, particularly in larger and more industrial segments. To determine participant weather sensitivity, Verdant applied a simple regression analysis to assess the relationship between load and outdoor temperature. The results were used to determine whether the candidate models for estimating impacts came from a group with various weather variables or from a group based on variables unassociated with weather. Sections 3.3.3 and 3.3.5 provide additional details on model groupings.

Using the interval load and weather data for months in the ELRP event season (May through October), the analysis used regression models of consumption on different thresholds of cooling-degree hours for each participant. If any of these models resulted in a parameter estimate with a probability ("p value") less than .05, the participant was deemed to be weather sensitive for that day type. Table 3-4 shows the count and share of participants who exhibited weather sensitivity by NAICS description and IOU.

TABLE 3-4: COUNT AND SHARE OF PARTICPANTS EXIHIBITING WEATHER SENSITIVITY BY NAICS AND IOU

	PG&E*		SCE	
NAICS Description	**Count**	**Share**	**Count**	**Share**
Agriculture, Mining & Construction	61	13%	4	40%
Institutional/Government	7	78%	9	100%
Manufacturing	18	44%	0	0%
Offices, Hotels, Finance, Services	135	75%	2	100%
Retail Stores	10	91%	2	100%
Schools	2	67%	0	0%
Wholesale, Transport, Other Utilities	26	41%	1	20%
Other	--	--	4	80%
Total	259	33%	22	56%

*PG&E counts and shares are based on counts of modeled service points.

3.3.3 Ex Post Model Groupings and Candidate Models

ELRP participants were placed into one of four modeling groups based on their weather sensitivity and NEM solar status. These groups and the number of participants by group are presented in Table 3-5.

TABLE 3-5: NUMBER OF PARTICIPANTS IN MODEL GROUPINGS BY IOU

IOU	Weather Sensitive and NEM	Weather Sensitive and Non-NEM	Non-Weather Sensitive and NEM	Non-Weather Sensitive and Non-NEM
PG&E*	37	222	131	395
SCE	3	19	0	17

*PG&E counts and shares are based on counts of modeled service points.

Participants in each model group are tested on a similar set of candidate models which include independent variables that are intended to help control for specific characteristics of these participants. For example, the weather-sensitive and non-NEM customers are tested on a set of candidate models that contain various specifications that include variables to account for weather effects on energy consumption. Conversely, non-weather sensitive participants select from a set of candidate models that do not include weather variables in the model specification. An additional feature of these groupings is the inclusion of NEM status. All NEM participants have the option to select a model that has station weather irradiance included as an independent variable. The idea is to capture the variability in net energy consumption as a result of Solar PV production, using irradiance as a proxy for PV production. However, NEM customers are also given the option of selecting models without solar irradiance.

Grouping participants in this way was only done for the development of individual regression models. Panel models with matched control groups were tested on a set of models resembling those of the Weather Sensitive and Non-NEM and Non-Weather Sensitive and Non-NEM groupings. In other words, panel models did not include solar irradiance. Table 3-6 presents the types of variables included in at least one candidate model specification by modeling group.

TABLE 3-6: VARIABLE TYPES INCLUDED IN CANDIDATE SPECIFICATION MODELING GROUPS

		Customer Specific Models				
Variable Type	**Variable Examples**	**Weather Sensitive and NEM**	**Weather Sensitive and Non-NEM**	**Non-Weather Sensitive and NEM**	**Non-Weather Sensitive and Non-NEM**	**Panel Models with Matched Control Group**
Weather	Cooling Degree Hours		✓			✓
Irradiance	Global Horizontal Irradiance	✓		✓		
Calendar Effects	Month, Day of Week,	✓	✓	✓	✓	✓
Baseline Adjustment	Average Morning Load	✓	✓	✓	✓	✓

3.3.4 Proxy Event Day Selection

The assessment of candidate model performance relies on the comparison between actual and predicted model performance on a set of days with event like conditions. These selected days are referred to as proxy event days. For most demand response programs with events coinciding with extreme temperature events, proxy event days are typically the remaining hot non-event days near events. However, some candidate model specifications also have solar irradiance included in the specification. As a result, proxy event days were also selected based on irradiance for non-weather sensitive NEM participants. Five weekday days and three weekend days were selected as proxy event days for each participant based on the maximum average temperatures between 1:00 pm and 11:00 pm. For non-weather sensitive NEM participants, five weekdays and three weekend days were selected based on the average maximum solar irradiance between 1:00 pm and 11:00 pm. For panel models, proxy days represent the five most frequently selected weekdays for participants in each respective modeling segment. No weekend proxy event days were selected for weekends as panel models were not utilized for the July 10th weekend event.

3.3.5 Impact Model Selection

Each set of candidate models were tested on proxy event days and assessed under several conditions. This process is depicted graphically in Figure 3-3. As presented, the model selection process begins with the development of a catalog of candidate model specifications and the selection of a set of proxy event days (discussed above). The candidate models are estimated using the proxy event days with presumed event hours to assess whether a model generates statistically significant parameters. If it does, the model specification is rejected because the models should not be finding impacts for events that did not occur. Next, Verdant's arbitration routine assesses the model coefficients for anticipated sign. A parameter designed to capture temperature effects, for example, should not be negative. Finally, the candidate models are estimated again, this time using the proxy event days as holdout days, which are used to assess the accuracy and bias of the model predictions out of sample. These metrics are used to select a final model from the candidates.

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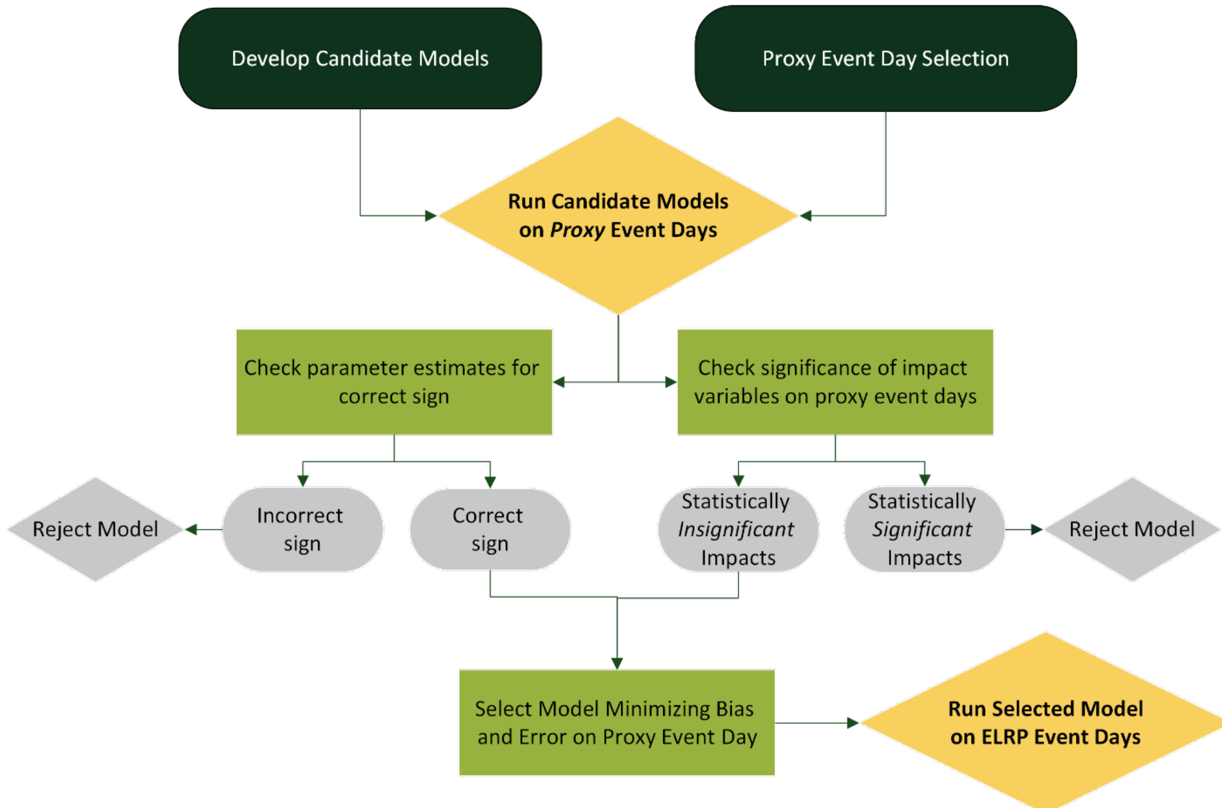
FIGURE 3-3: EX POST IMPACT MODEL ARBITRATION



3.3.6 Impact Estimation

As stated previously, the estimation of ex post models relies on a combination of individual customer specific regression models and panel models with matched control groups. Individual regression models were selected and used to estimate impacts for all participants, regardless of whether they were included in panel modeling. Equation 1 presents the general model specification used to estimate ex post impacts.

EQUATION 1: GENERAL MODEL SPECIFICATION

$$kWh_{e,d,h} = \beta_0 + \beta_{1e,h}EventDay_eHour_h + \beta_2 Temp_h + \beta_3 Irr_h + \beta_{4,h}Hour_h + \beta_{5,m}Month_m + \beta_{6,d}Wday_d + \beta_{7,h}OtherEventHour_h + \varepsilon$$

Where:

$kW\mathrm{h}_{\mathrm{e,d,h}}$	The net load on day *d* in hour *h* during event *e*
β_0	The intercept of the regression model
$EventDay_eHour_\mathrm{h}$	The interaction between the event day dummy and hour. Its coefficient, $\beta_{1e,\mathrm{h}}$, yields the impact of an event on event day e during hour h

$Temp_{\mathrm{h}}$	A temperature variable in hour h.
Irr_{h}	A solar irradiance variable in hour h.
$Hour_{\mathrm{h}}$	A dummy variable for each hour h
$Month_{m}$	A dummy variable for each month m
$Wday_{d}$	A dummy variable indicating the day of the week d
$OtherEventHour_{h}$	A dummy variable indicating whether hour h is an event hour for a participant in another demand response program
ε	An error term

The interaction between $EventDay_{e}Hour_{\mathrm{h}}$ results in a set of 24 $\beta_{1e,h}$ estimates that capture event day specific impacts. These sets of 24 estimates are used to establish program impacts during the event window and capture any other event day effects, such as precooling or snapback, for hours outside of the event window. In essence, $\beta_{1e,h}$ captures the difference between actual event day load and the estimated baseline. For the ex post analysis, $\beta_{1e,h}$ estimates over the event window provide the impact estimates of interest.

Overlapping BIP and ELRP Event Hours

As previously stated, July 9th is a multi-program event day for ELRP participants dually enrolled in the BIP. More specifically, the hours ending 19 through 21[17] are overlapping event hours. As a result, all impacts in those hours are captured by $\beta_{7,h}$ in those hours and $\beta_{1e,h}$ estimates are set to zero. In other words, all impacts during overlapping program event hours are attributed to BIP participation in the modeling of ELRP impacts. Additionally, the last ten minutes of hour ending 18 is part of the BIP dispatch for SCE. As result, load reductions for SCE's hour ending 18 were also attributed to BIP given no evidence of full load reductions during this event hour.

The evaluation team explored whether some BIP event hour impacts should be attributed to ELRP participation during the overlapping BIP hours. For this exercise, the July 9th event day load reductions (actual observed load) were compared with BIP Firm Service Level (FSL) commitments, which represent a participant's BIP committed level of load reduction. Since the BIP program does not credit BIP participants for load reductions beyond their FSL, any load reductions beyond FSL commitments could be attributed to ELRP participation. However, the evaluation found that, on average, BIP participants do not reduce their load beyond their FSL during overlapping event hours. As a result, the inclusion of overlapping BIP

[17] The actual overlapping BIP event window for PG&E was 18:30-20:30 on July 9th. Hour ending 19 and 21 are partial PG&E BIP event hours.

event hour load impacts into the ELRP baseline is appropriate for the ex post analysis. Section Appendix D presents the findings from the described FSL examination.

3.4 EX ANTE IMPACT METHODOLOGY

The goal of the ex ante impact analysis is to estimate program impacts into future years under varying 1-in-10 and 1-in-2 weather scenarios across the ELRP event window (4:00 pm to 9:00 pm).[18] Given that the ELRP is a pilot program, the ex ante analysis seeks to provide ex ante estimates for program years 2022 through 2025. Additionally, the ex ante analysis was conducted using two approaches. These include "top-down" and "bottom-up" approaches. These approaches are described in the following subsections.

It should first be noted that ex ante analysis only seeks to estimate impacts for Group A.1 participants for both PG&E and SCE. The primary reason is that there was no event participation for Groups A.3, A.4, B.1 and B.2[19] for both IOUs and no participation in Group A.2 for SCE. As a result, there are no ex post impacts to inform a LIP-based ex ante analysis. Additionally, it was decided to not produce ex ante impacts for PG&E A.2 because there are virtually no impacts associated with the A.2 customers (discussed in Section 4). In essence, there is no active Group A.2 program activity to inform weather-adjusted impacts or ex ante forecasts.

Additionally, there are substantive program changes between PY 2021 and PY 2022 that limit the usefulness of the LIP based ex ante analysis. These changes include the doubling of program incentives, SCE's modification of the minimum threshold for A.1 participation from 200 kW of peak load to 100 kW and expansion of Group A.2 to all non-BIP, non-residential aggregators. Additional ELRP program changes are included in CPUC decisions 21-06-027 and 21-12-015.

3.4.1 Top-Down Ex Ante Impacts

The top-down ex ante impacts are based on the participant and MW forecasts provided by PG&E and SCE, which are in turn based on participant nominations (or stated available load reductions). Simply put, the top-down ex ante impacts take the participant and MW forecasts from the utilities as truth, so the stated MW forecast for Group A.1 customers is the top-down aggregate forecast for each year and the average per participant impacts is the number the MW forecast divided by the participant forecast (and converted from MWh/h to kWh/h). Participant characteristics and relative shares of nominated capacity from the 2022 participants are then used to allocate the MW forecast the relevant ex ante subgroups. This

[18] The 1-in-2 and 1-in-10 weather scenarios include a typical event day, monthly IOU system peak and monthly IOU CAISO system peak and vary for PG&E and SCE.

[19] PG&E had CBP aggregators and DRPs enrolled in in the ELRP, however, no group B events called for PY 2021.

approach is not weather normalized, does not account for persistence of COVID-19, does not provide for uncertainty adjustments, and is not in accordance with the Load Impact Protocols.

3.4.2 Bottom-Up Ex Ante Impacts

The bottom-up ex ante impacts are derived from the weather-normalized ex post impacts and follow the standard practice outlined in the Load Impact Protocols. However, the results from the ex post analysis required some modifications to produce bottom-up ex ante analysis. Because the ex post analysis estimates weekend and weekday event impacts separately, to produce one set of ex ante impacts, the weekend and weekday impacts were estimated together with slight modification to the individual participant weekday models used for ex post estimation. These adjustments include:

- The ex post model term $\beta_{1e,h}EventDay_eHour_h$ impact estimator was altered to $\beta_1 EventHour$ for non-weather sensitive customers and to $\beta_1 CDH65 * EventHour$ for weather sensitive participants, where the $EventHour$ is the dummy variable indicating an event hour and $CDH65$ is a seasonal weather variable. For summer cooling sensitive customers, the CDH65 term allows for ex ante impacts to “adjust” accordingly in each weather scenario.

- Weekday dummy variables ($Wday_d$) were set to 0.142 when producing ex ante estimates of baseline load. This value represents the average weekday dummy value (1 divided by 7) for each day of the week. For model specifications that do not include dummy variables for the day of the week a $Weekend_d$ dummy variable was added to the regression to control for changes in load between weekday and weekend days.

The weather normalized impacts are then weighted to account for the appropriate distributions of ELRP Group A.1 participants based on the forecasted participant counts. More specifically, participants are weighted based the forecasted distributions of NAICS description, customer size and SubLAP. Additionally, these impacts are increased by 20% to account for the increase in incentives between PY 2021 and PY 2022[20] and segments of NAICS description, customer size and SubLAP that had negative load impacts (load increases) were set to zero. The weather-adjusted per customer impacts are then multiplied by the number of forecasted participants in that segment and year.

3.4.3 Ex Ante Forecasts

PG&E and SCE provide their participant and MW forecasts for Group A.1, which are presented in Figure 3-4 and Figure 3-5, respectively. PG&E forecasts 117 MW of available curtailment and 1,582 participants in 2022, with no expected growth for A.1 participation through the life of the ELRP pilot. SCE is forecasting 54.9 MW of available curtailment and 211 participants for 2022, with 15% growth in enrollment and MWs

[20] Twenty percent load impact increases are based on PG&E price elasticity assumptions.

year over year through the life of the pilot. While both utilities provided participant forecasts, PG&E provided their forecast by industry, customer size, dual enrollment status, and SubLAP, whereas SCE provided a singular annual participant enrollment count. As a result, Verdant used the distribution of enrolled A.1 customers as of 3/15/2021 and their associated characteristics to proportionally distribute SCE's forecast into bins by NAICS description, customer size, and SubLAP.

FIGURE 3-4: PG&E GROUP A.1 ENROLLMENT (LEFT) AND MW (RIGHT) FORECAST BY YEAR

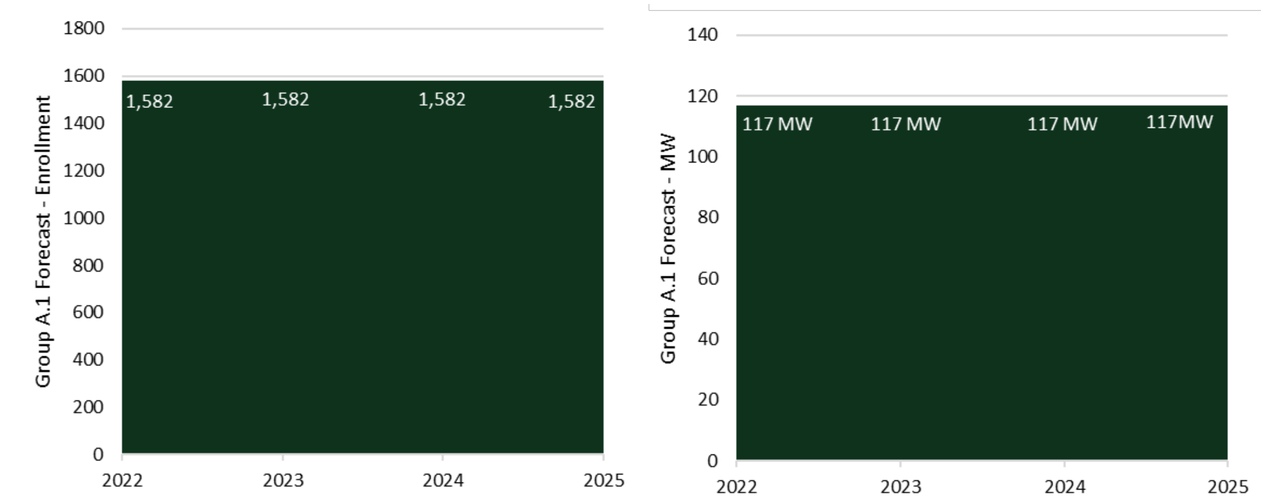
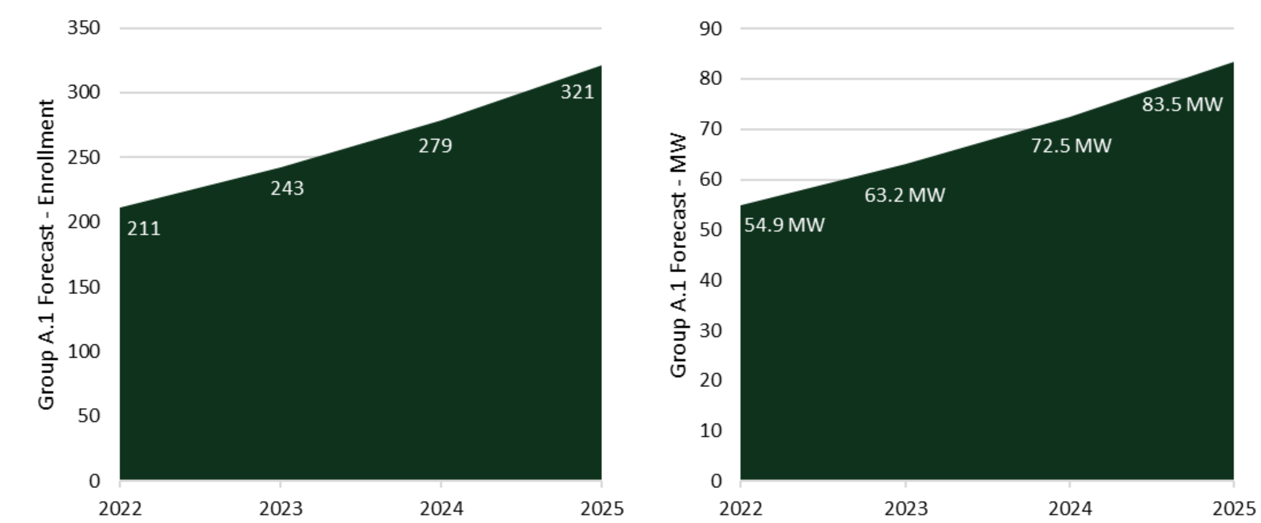


FIGURE 3-5: SCE GROUP A.1 ENROLLMENT (LEFT) AND MW (RIGHT) FORECAST BY YEAR



3.4.4 COVID-19 Ex Ante Adjustments

The COVID-19 pandemic has affected many utility customers and their load profiles. Verdant's approach to identify any effects and account for them is to compare the usage patterns from 2019, before the pandemic, with usage in subsequent years to develop adjustment factors to apply to the predicted load profiles in the ex ante forecasts to account for a return to pre-pandemic conditions. Specifically, the development of COVID-19 adjustments results from a simple linear regression of aggregated participant load by NAICS as described in Equation 2. The equation does not contain an intercept so that β_{1y} are estimated for each year

EQUATION 2: COVID-19 EFFECTS ESTIMATION

$$kWh_{y,m,h} = \beta_{1y}Year + \beta_{2h}Hour + \beta_{3m}Month + \beta_4 CDH65 + \varepsilon$$

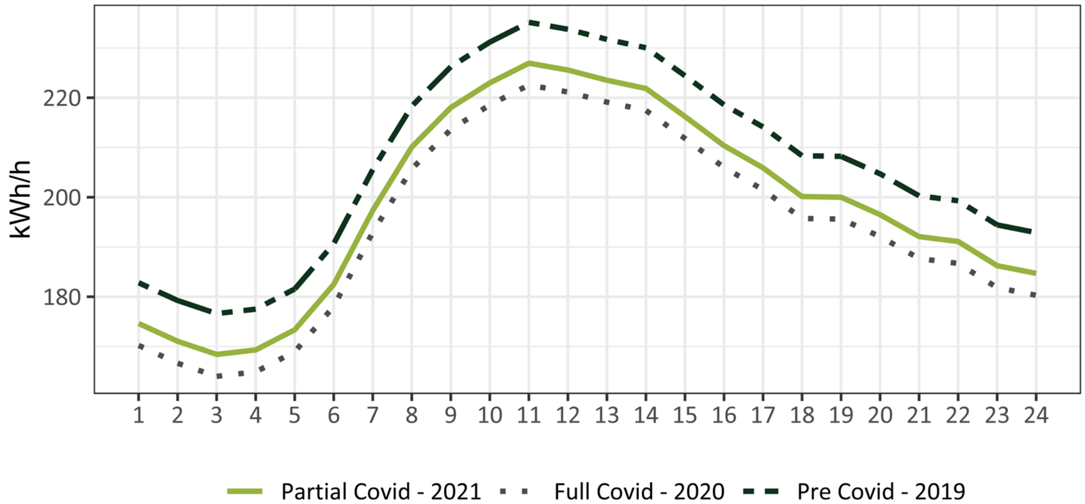
Where:

$kWh_{y,m,ht}$	is the estimated load in year y, month m, and hour h
β_{1y}	is a set of coefficient estimates associated with the effect on of Year y and is used as a proxy for COVID-19
$Year$	is a categorical variable indicating the year
$Hour$	is the hour of the day (HE 1 through HE 24)
$Month$	is the month in the ELRP event season (May through October)
$CDH65$	is the cooling degree hours with base of 65 used to normalize weather variations
ε	is the error term

The variables of interest in the regression equation are the β_{1y}, which represent the year effects of ELRP loads. Because the event season for ELRP is May through October, the data were limited to these months for the COVID-19 analysis. As result, each year's set of data represents a set of COVID-19 conditions, with 2019 representing pre-COVID, 2020 representing full-COVID, and 2021 representing partial COVID-19. A comparison between the predicted load shapes under 2019, 2020 and 2021, provide estimates of initial COVID-19 impacts and their return to normalcy.

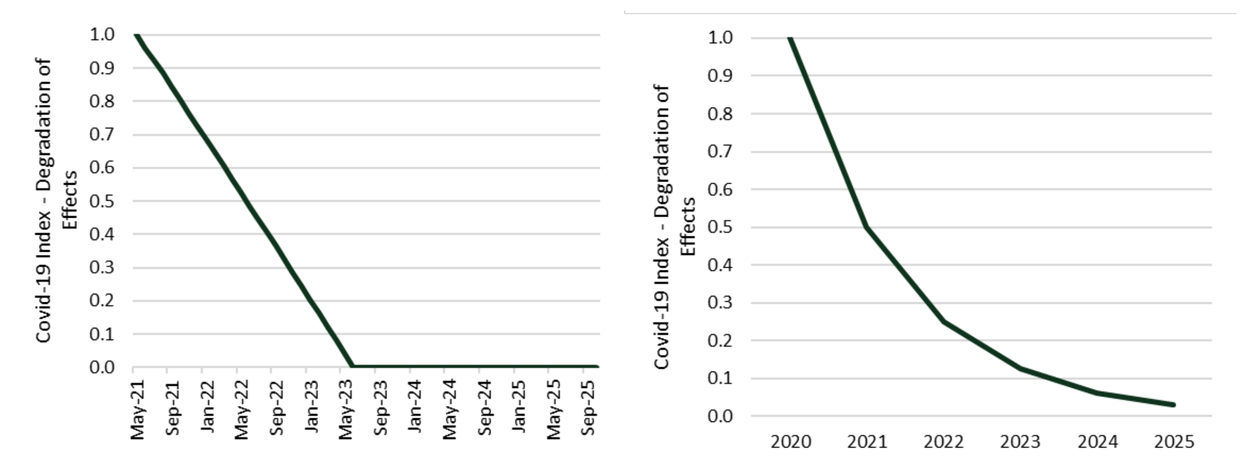
It should be noted that not all industries necessarily experience significant changes in load because of COVID-19. For example, agricultural businesses and their associated energy consumption are not necessarily affected by COVID-19, or at least not in the same way as other industry segments, such as office or retail customers, which have seen a substantial drop in usage. For this reason, the effects of COVID-19 are explored at the industry level. A typical COVID-19 path for non-residential customers is presented in Figure 3-6 below. As seen, the 2019 load shape, which represents pre-COVID-19 conditions, was at the highest overall load. In 2020 there is a large drop in overall load as the US economy feels the initial effects of COVID-19 shelter-in-place orders, followed by a rebound in energy consumption in 2021 as the economy returns to normalcy.

FIGURE 3-6 EXAMPLE OF COVID-19 EFFECTS ON LOAD



Both PG&E and SCE have assumed glide paths for the degradation of lingering COVID-19 effects. These glide paths were converted into indexes that represent the relative strength of COVID-19 effects. For example, an index of 1.0 represents full COVID-19 impacts, an index of 0.5 represents that half of the COVID-19 impacts are still present and an index of zero indicates a full return to pre-pandemic conditions.

FIGURE 3-7 PG&E (LEFT) AND SCE (RIGHT) COVID-19 GLIDE PATH INDEXES



The combination of β_{1y} estimates and the COVID-19 indexes then result in monthly COVID-19 adjustments calculated as described in Equation 3.

EQUATION 3: COVID-19 ADJUSTMENT FACTORS

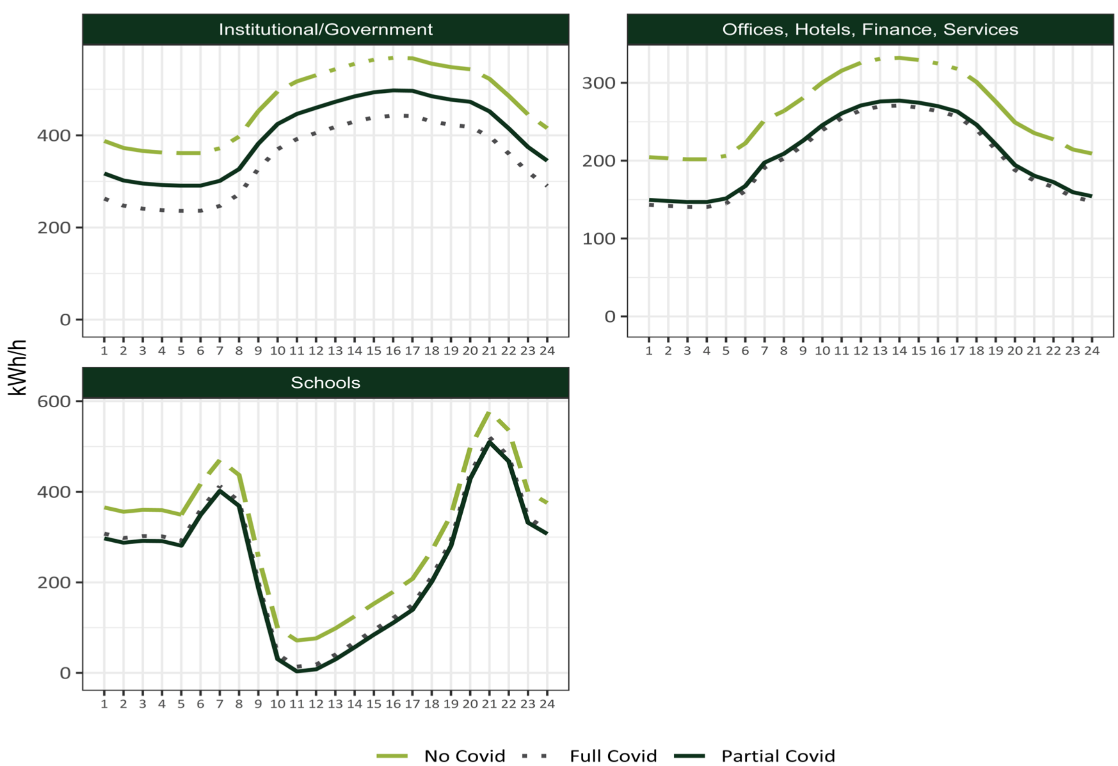
$$Covid19\ Adjustment_{i,y,m} = 1 + ((\beta_{1,i,2019} - \beta_{1,i,2021}) / \beta_{1,i,2019}) * (Covid19\ Index)_{m.y}$$

Where:

$Covid19\ Adjustment_{i,y,m}$	Is the COVID-19 Adjustment factor for NAICS *i* in year y and month *m*
$((\beta_{1,i,2019} - \beta_{1,i,2021}) / \beta_{1,i,2019})$	is the relative persisting COVID-19 effect in 2021 for industry NAICS *i*
$Covid19\ Index_{m.y}$	Is the COVID-19 index for year *y* in month *m*

It should be noted that COVID-19 adjustment factors are only applied to industries with statistically significant year impacts and where predicted β_{1y} estimates make intuitive sense, which means that 2020 saw a drop from 2019 and 2021 showed some return to normal. As a result, only three NAICS groups received COVID-19 impact adjustment. These groups include "Institutional/Government", "Offices, Hotels, Finance, Services", and "Schools". The predicted load profiles for these segments under the varying COVID-19 conditions are presented in Figure 3-8 below. Given that PY 2021 is the first year of the ELRP, adjustment factors are only applied to ex ante baselines, as there is no pre-COVID-19 reference for load reductions.

FIGURE 3-8: ELRP NAICS GROUPS WITH PERSISTING COVID-19 EFFECT



3.5 UNCERTAINTRY ADJUSTED IMPACTS

Both the ex post and ex ante analysis require estimation of uncertainty adjusted load impacts at the 10th, 30th, 70th, and 90th percentiles. The uncertainty adjustments for both ex post and ex ante analysis result from the variances surrounding the impact estimators in the regressions described above. The variances are then summed across participants in each level of aggregation and hour for each event and the average event day. Verdant assumed that the variances were normally distributed and converted the sum of the variances into standard deviations that were then used to provide uncertainty adjusted impacts for the required percentiles. While these adjustments are largely not discussed in this report, they are presented in both the ex post and ex ante table generators (Appendix A).

4 EX POST RESULTS

The primary objective of the ex post analysis is to provide estimates of event-day load reductions and for a typical event day. As stated previously, there were four event days for PG&E and three event days for SCE in 2021. The average event day for PG&E and SCE Group A.1 includes the average hourly impacts and participation across all event days, excluding June 17th. June 17th is only an event day for PG&E and was excluded from the PG&E average event day due to its smaller event window (2 hours) and lower participation (30 participants) compared to the remaining event days.

While all Group A.2 BIP aggregators were notified of each ELRP event, they are only compensated for participation during overlapping BIP event hours. As a result, it would be reasonable to only expect load reductions on event days with overlapping BIP event hours. Therefore, the average event day for Group A.2 participants is the July 9th event day due to the occurrence of an overlapping BIP event day.

As discussed previously, July 9th was an event day for PG&E and SCE for both ELRP and BIP for dually enrolled participants. This has significant implications on both baseline estimates and observed event-day loads. As mentioned previously in the methodology section, the impacts during overlapping BIP event hours are attributed solely to the BIP program. As a result, the event day baselines account for the BIP load reductions in the overlapping event hours. Section 4.3 provides further details on dually enrolled BIP participation in the ELRP.

4.1 PG&E IMPACTS

Visually representing event day load shapes and estimated baseline is a powerful tool for understanding event day activity and for framing impact estimates. For this reason, this report first presents event day load shapes for the Group A.1 and Group A.2 average event day before discussing the impacts for separate events. Figure 4-1 and Figure 4-2 show the average event day load profiles for Group A.1 and Group A.2 participants. Given that events occurred on varying hours across event days, the density of the shaded areas relates to the frequency of event days where a given hour was an event hour. The opaquer the shading on an event hour, the more frequently that hour was an event hour. Appendix B presents the load shapes for each event day for Group A.1 and Group A.2.

The average event day for PG&E A.2 participants is the same as the July 9th event day. While there are a small number of BIP participants enrolled through the A.1 pathway, A.2 participants exclusively represent BIP aggregators. As a result, all A.2 load reductions are attributed to BIP in hours ending 19 through 21 on the average event day.

FIGURE 4-1: PG&E AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – GROUP A.1

[redacted]

FIGURE 4-2: PG&E AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – GROUP A.2

[redacted]

4.1.1 PG&E Average Hourly Event Impacts

Table 4-1 and Table 4-2 provide the average event hour impacts for each event day for PG&E A.1 and A.2 participants, respectively. On average, PG&E A.1 participants provided an average of [redacted] MW of load reduction in each ELRP event hour. The largest load reductions, on average, occurred on July 10th, with an average hourly load reduction of [redacted] MW (or 7.1% of the estimate baseline).

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TABLE 4-1: 2021 ELRP AVERAGE EVENT HOUR IMPACT - GROUP A.1

Event Date	Event Window	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Service Point Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
June 17th	19:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
July 9th	17:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
July 10th	17:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
July 29th	18:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Avg. Event	18:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Group A.2 participants provided negligible load reductions during 2021. While Group A.2 participants were dispatched for the BIP event on July 9th, there were no obvious indicators of significant curtailment associated with ELRP participation. On average, Group A.2 participants reduced their load by 0.7% on the average event day.

While Group A.2 participants were not compensated for participation on non-BIP ELRP event days, BIP aggregators were notified for events and could in, theory, voluntarily participate. However, there is no evidence that Group A.2 participants responded to events on non-BIP ELRP event days given the small and negative average percent load reductions (-6.8% to 2.1%) and event day load shapes presented in Appendix D. It should be noted that the July 10th event day load impacts (load increases) are likely influenced by the BIP event participation in the prior event day. For example, it may be that some participants consume more energy than normal in the day after a BIP event due to a schedule shift in routine operations.

TABLE 4-2: 2021 ELRP AVERAGE EVENT HOUR IMPACT - GROUP A.2

Event Date	Event Window	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Service Point Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
June 17th	19:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
July 9th	17:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
July 10th	17:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
July 29th	18:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Avg. Event[21]	17:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[21] Average excludes 06/17, 07/10, and 07/29 events.

Table 4-3 and Table 4-4 below present the average event hour impacts on the average event day by NAICS description, customer size and LCA (Local Capacity Area). The participant types that provide the largest relative load reductions on average include participants 200 kW or greater, Institutional/Government, Offices Hotels Finance Services, and Wholesale, Transport, Other Utilities. However, Manufacturing provided the largest aggregate load reductions on average.

TABLE 4-3: GROUP A.1 AVERAGE EVENT DAY IMPACTS BY NAICS DESCRIPTION AND CUSTOMER SIZE

Group	Subgroup	Num. of Parts.	Avg. Reference Load (kWh/h)	Avg. Customer Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
All	All	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Size	Under 20 kW	39	2.6	0.0	-0.3%	0.0	95.4
	20 kW to 199.99 kW	431	44.2	0.0	0.0%	0.0	102.4
	200 kW or Greater	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unknown	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NAICS Desc	Agriculture, Mining & Construction	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Institutional/Government	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Manufacturing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Offices, Hotels, Finance, Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Retail Stores	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Schools	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Wholesale, Transport, Other Utilities	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unknown	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LCA*	Greater Bay Area	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Greater Fresno Area	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Humboldt	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Kern	61	91.3	1.7	1.9%	0.1	106.6
	North Coast and North Bay	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Sierra	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Stockton	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unknown	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

*Impacts for LCA do not sum to the total 9.1 MW due to rounding and the reliance on individual models rather than a combination of individual and panel models.

As discussed above, Group A.2 participants did not significantly reduce their load on average. However, “Manufacturing” and “Offices, Hotels, Finance, Services” NAICS groups did provide relative load reductions of 6.8% and 17.7% respectively. However, these impacts are small nominally.

TABLE 4-4: GROUP A.2 AVERAGE EVENT DAY IMPACTS BY NAICS DESCRIPTION AND CUSTOMER SIZE

Group	Subgroup	Num. of Parts.	Avg. Reference Load (kWh/h)	Avg. Customer Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
All	All	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Size	20 kW to 199.99 kW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	200 kW or Greater	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unknown	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NAICS Desc	Agriculture, Mining & Construction	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Manufacturing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Offices, Hotels, Finance, Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Wholesale, Transport, Other Utilities	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unknown	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LCA	Greater Bay Area	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Greater Fresno Area	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Kern	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Sierra	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Stockton	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unknown	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 4-5 and Table 4-6 present the aggregate hourly load impacts for Group A.1 and A.2 average event days as presented in the ex post table generator. The highlighted hours represent event hours. Hour ending 18 for group A.1 is a blend of event and non-event hours and is therefore shaded differently.

TABLE 4-5: AGGREGATE HOURLY LOAD IMPACTS FOR AN AVERAGE EVENT DAY – PG&E GROUP A.1

Hour-Ending	Estimated Reference Load (MWh)	Observed Event Day Load (MWh)	Estimated Load Impact (MWh/h)	Average Temperature (Deg F)	Uncertainty Adjusted Impact (MWh)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
By Period:	Estimated Reference Load (MWh/h)	Observed Event Day Load (MWh/h)	Estimated Load Impact (MWh/h)	Average Temperature (Deg F)	Uncertainty Adjusted Impact (MWh/h)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
Daily	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Event Hour	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

TABLE 4-6: AGGREGATE HOURLY LOAD IMPACTS – PG&E GROUP A.2 TYPICAL EVENT DAY

Hour-Ending	Estimated Reference Load (MWh)	Observed Event Day Load (MWh)	Estimated Load Impact (MWh)	Average Temperature (deg F)	Uncertainty Adjusted Impact (MWh)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

By Period:	Estimated Reference Load (MWh/h)	Observed Event Day Load (MWh/h)	Estimated Load Impact (MWh/h)	Average Temperature (Deg F)	Uncertainty Adjusted Impact (MWh/r)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
Daily	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Event Hour	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

4.2 SCE IMPACTS

As with the PG&E ex post impacts discussed above, examining the visual representation of event day activities provides greater context surrounding ex post impacts. Given that events occurred on varying hours across event days, the density of the shaded areas relates to the frequency of event days where a given hour was an event hour. The darker (opaquer) an event hour, the more frequent that hour was an event hour. Appendix B presents the load shapes for each event day for SCE Group A.1.

FIGURE 4-3: SCE AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – GROUP A.1

[redacted]

4.2.1 SCE Average Hourly Event Impacts

Table 4-7 provides details on the average event hour impacts for the 2021 SCE ELRP participant population across event days and on the average event day. As seen in Table 4-7 and the figures above, the SCE ELRP did not see load reductions, on average, for any event during the 2021 event season. The average hourly event day impact for the 2021 ELRP was [redacted] MW (an increase in load). This load increase is primarily driven by the two largest ELRP participants either not curtailing during event hours, delayed snapback from prior days of participation in BIP, or dispatching at the incorrect time (discussed in Section 4.2.2). These two participants are referred to as "non-performers" in this report.

TABLE 4-7: 2021 ELRP AVERAGE EVENT HOUR IMPACTS

Event Date	Event Window	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Customer Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
July 9th	17:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
July 10th	17:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
July 29th	18:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Avg. Event	17:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 4-8 presents the average event hour impacts on the average event day by NAICS description and customer size. The participant types that provide the largest relative load reductions on average, include Mining & Construction and Offices Hotels Finance Services. It is also worth mentioning that the non-performers belong to the Manufacturing and Wholesale, Transport, Other Utilities NAICS categories (one in each). Schools and retail stores also saw negative load reductions; however, these segments only participated on one event day and had two and one participant, respectively.

TABLE 4-8: GROUP A.1 AVERAGE EVENT DAY IMPACTS BY NAICS DESCRIPTION AND CUSTOMER SIZE

Group	Subgroup	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Customer Impact (kWh/h)	Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
All	All	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Size	51 to 250 kW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	250 or more kW	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NAICS Description	Agriculture, Mining & Construction	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Entertainment and Government	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Manufacturing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Offices, Hotels, Finance, Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Retail Stores	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Schools	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Wholesale, Transport, Other Utilities	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LCA	Big Creek/Ventura	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	LA Basin	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unknown	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 4-9 presents the aggregate hourly load impacts for the Group A.1 average event days as presented in the ex post table generator. The highlighted hours represent event hours. Hour ending 18 for group A.1 is a blend of event and non-event hours and is therefore shaded differently.

TABLE 4-9: AGGREGATE HOURLY LOAD IMPACTS FOR A TYPICAL EVENT DAY – SCE GROUP A.1

Hour-Ending	Estimated Reference Load (MWh)	Observed Event Day Load (MWh)	Estimated Load Impact (MWh/h)	Average Temperature (Deg F)	Uncertainty Adjusted Impact (MWh)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

By Period:	Estimated Reference Load (MWh/h)	Observed Event Day Load (MWh/h)	Estimated Load Impact (MWh/h)	Average Temperature (Deg F)	Uncertainty Adjusted Impact (MWh/h)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
Daily	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Event Hour	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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4.2.2 Reasons for SCE Load Increases

As discussed above, the main contribution to load increases resulted from two non-performers. Figure 4-4 and Figure 4-5 present the event day load shapes for these non-performers. Each figure presents the July 9th event day on the top left, the July 10th event day on the top right and the July 29th event on the bottom. Non-performer number one belongs to the Manufacturing NAICS group and non-performer number two belongs to the Wholesale, Transport, Other Utilities group.

As seen in Figure 4-4 below, non-performer number one (a dually enrolled BIP participant) was dispatched for the July 9th BIP event (not participating during the first hour of the ELRP event) and then remained offline until mid-morning on July 10th. Then this participant's load is increased by several MW (compared to the baseline) on the following July 10th event day window, likely to make up production from the day before. Additionally, this participant either erroneously dispatched or shut down processes temporarily between hours ending 10 and 12 on July 29th and then ignores the actual event window as presented in Figure 4-4. It should be noted that all impacts during overlapping BIP event hours are solely attributed to BIP as a result, these impacts are included in the baseline on the July 9th event day. Non-performer number one never appropriately responds to or participates in an ELRP event dispatch for an ELRP event, resulting in multiple MW of load increases during event hours.

FIGURE 4-4: NON-PERFORMER NUMBER ONE ELRP PARTICIPATION

[redacted]

Figure 4-5 describes the event day activities for non-performer number two, who is the largest participant in the ELRP. While this non-participant performer had the potential to produce significant load reductions, they never reduced their load in a way that is detectible through modeling or visual examinations of load shapes. Additionally, this non-participant performer appears to slightly increase their load on the July 29th event day. While this load increase is relatively small (less than two percent) for this participant, the increase is nominally large compared to other participant load reductions on this event day, contributing to overall event day load increases.

FIGURE 4-5: NON-PERFORMER NUMBER TWO ELRP PARTICIPATION

[redacted]

Table 4-10 below presents the average hourly load reductions on the average event day with and without the two non-performers. As seen, there are net positive load reductions, on average, when these two non-participants performers are excluded from the overall population. However, these reductions are still modest (two percent of load). It is worth noting that the most egregious non-performer, non-performer number one, is no longer enrolled in the ELRP. However, non-performer number two was still enrolled as of March 15, 2022.

TABLE 4-10: 2021 ELRP AVERAGE EVENT HOUR IMPACTS WITH AND WITHOUT NON-PERFORMERS

Event Day	Non-Performer Inclusion	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Customer Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
July 9th	With	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Without	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
July 10th	With	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Without	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
July 29th	With	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Without	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Avg. Event	With	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Without	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

4.3 DUALLY ENROLLED PARTICIPANT PERFORMANCE - JULY 9TH EVENT DAY

Dual enrollment is a key feature of the ELRP. This is especially true for Group A.2 and Group B participation pathways. For this reason, it is important to understand how dually enrolled participants curtail their load on event days with overlapping DR participation. In 2021, there were a total of 94 PG&E and 4 SCE participants that were dispatched on July 9th for ELRP and BIP events.

Figure 4-6 and Figure 4-7 describe the dually enrolled participant aggregate load shapes on July 9th. In these figures event hours are presented as ELRP only event hours (hour ending 18)[22] and dual event hours (hour ending 19 through 21). As seen for both PG&E and SCE, dually enrolled participants do not reduce their load for the ELRP only hours prior to the start of the BIP event.[23] Only once the BIP event starts are load reductions present. However, the evidence suggests that load reductions during dual event hours are attributed to BIP, rather than the ELRP.

The July 9th event performance, along with the absence of PG&E Group A.2 load reductions (presented in Table 4-2) and event performance of SCE non-performer number one (presented in Figure 4-4) suggest that dually enrolled BIP participants do not respond to ELRP event notifications. It should be noted, however, that SCE non-performer number one has de-enrolled from the PY 2022 ELRP.

[22] The last 10 minutes of hour ending 18 is part of the BIP event dispatch for SCE.

[23] PG&E dually enroll participants produced modest load reduction on average in hour ending 18 of July 9th on average. However, this load reduction is less than 0.5% of the reference load and is likely “noise” in estimation of the estimated reference loads

FIGURE 4-6: PG&E GROUP A.1 AND A.2 DUALLY ENROLLED PARTICICPANT JULY 9TH EVENT DAY LOAD

[redacted]

FIGURE 4-7: SCE GROUP A.1 DUALLY ENROLLED PARTICIPANT JULY 9TH EVENT DAY LOAD

[redacted]

4.4 ELRP NOMINATIONS VS EX POST IMPACTS

ELRP participants provide stated levels of nominated load reductions when enrolling into the program. For PG&E's Group A.1 participants, Figure 4-8 provides a comparison of the nominated load reductions along with the estimated ex post impacts for each event day. For the June 17th event, which consisted of a smaller group of accounts, the ex post impacts were higher than the nominations. For the three other 2021 events, the discrepancy between nominated and ex post impacts is stark, suggesting the observed load reductions were far lower than what participants believed they were capable of providing. However, it is important to keep in mind that all PY 2021 events were day-of notifications. Had the events been called day-ahead, there may have been more load reductions provided. It is also worth noting that nominations were not available for all participants, as a result, the presented nominations are biased low.

FIGURE 4-8 PG&E GROUP A.1 NOMINATIONS VS. EX POST IMPACTS

[redacted]

Similarly, the 2021 nominations were explored for SCE's Group A.1 participant population. Figure 4-9 and Figure 4-10 present comparisons of the nominated load reductions along with the estimated ex post impacts for each event day with and without the two SCE non-performers (respectively). As seen the total nominations for SCE's participant population 17.5 MW for the July 9th and July 10th event days and 18.5 MW for the July 29th event. However, there were no load reductions (on average). Despite this, when the non-performers are removed from the analysis, there are positive load reductions, on average, for the July 9th and July 10th event days ([redacted] MWh/h and [redacted] MWh/h respectively). However, the load reductions still fall significantly short of the nominated load (13.1 MW for the July 9th and July 10th event days and 14.1 MW for the July 29th event).

FIGURE 4-9 SCE GROUP A.1 NOMINATIONS VS. EX POST IMPACTS WITH NON-PERFORMERS

[redacted]

FIGURE 4-10 SCE GROUP A.1 NOMINATIONS VS. EX POST IMPACTS WITHOUT NON-PERFORMERS

[redacted]

While demand response evaluations do not typically explore realization rates, the ELRP evaluation explored the realization of nominations for Group A.1 customers to highlight the differences between stated and realized load reductions. The ELRP does not currently have a mechanism that holds participants to their stated nominations. As a result, understanding the realization rates may help inform expectations for future load reductions. The nomination realization rates were calculated for ELRP events as the ex post evaluated MW divided by the nominated MW. This results in a value that represents the share of nominations achieved for each event. A value of 100% indicates that all of the nominations were achieved during a given event, above 100% indicates an event that exceeded nominations and below 100% represents an event day where nominations were not achieved. Since negative load reduction represent the absence of load reductions, realization rates were capped at 0% for events with negative load impacts (load increases). The nominations' realization rate for events are presented in Table 4-11 for PG&E and in Table 4-12 for SCE (with and without the previously described non-performers).

TABLE 4-11 PG&E GROUP A.1 NOMINATIONS' REALIZATION RATES BY EVENT

Event Date	Nomination Realization Rate
June 17th	238%
July 9th	17%
July 10th	24%
July 29th	10%

TABLE 4-12 SCE GROUP A.1 NOMINATIONS' REALIZATION RATES BY EVENT

Event Date	Nomination Realization Rate with Non-Performers	Nomination Realization Rate without Non-Performers
July 9th	0%	3%
July 10th	0%	9%
July 29th	0%	0%

5 EX ANTE IMPACTS

This section presents results from the ex ante impact analysis. The goal of the ex ante impact analysis is to estimate program impacts in future years under various 1-in-10 and 1-in-2 weather scenarios[24] across the ELRP event window (4:00 pm to 9:00 pm). Given that the ELRP is a pilot program, the ex ante analysis seeks to provide ex ante estimates for program years 2022 through 2025.

The ex ante impacts analysis seeks to produce ex ante impacts for Group A.1 participants using two methods, “top-down” and “bottom-up”. At a high level the “top-down” approach is derived from the utility ELRP 2022-2025 MW and enrollment forecast and is driven by participant nominations. This approach is not weather normalized and does not follow the Load Impact Protocols methodology and simply relies on allocating the forecasted MW and participants into binned participant characteristics. The bottom-up approach is based on weather-normalized ex post impacts and follows typical methodology for ex ante impacts outlined in the CPUC’s Load Impact Protocols.

5.1 PG&E EX ANTE IMPACTS

5.1.1 Top-Down

As mentioned, the top-down approach for estimating ex post impacts takes the MW and participant forecast, allocates impacts into the respective participant segments and takes the total MW forecast as truth for aggregate ex ante impacts. The average participant impact is the total MW divided by the number of participants in the population. As a result, the top-down ex ante impacts are 117 MW in aggregate and 74.0 kWh/h per participant (see Table 5-1). Given that these impacts are not weather normalized, the ex ante impacts are the same under 1-in-2 and 1-in-10 weather scenarios.

Table 5-1 presents the top-down ex ante per participant and aggregate impacts for PG&E Group A.1. As seen, the “Agriculture, Mining & Construction”, “Offices, Hotels, Finance, Services” are expected to provide the majority of PY 2022 impacts based on MW and enrollment forecasts.

[24] The 1-in-2 and 1-in-10 weather scenarios include a typical event day, monthly IOU system peak and monthly IOU CAISO system peak and vary for PG&E and SCE.

TABLE 5-1: PY 2022 PG&E GROUP A.1 TOP-DOWN EX ANTE MW FORECAST BY CUSTOMER SIZE, NAICS DESCRIPTION AND LCA

Group	Subgroup	PY 2022 Forecasted Enrollment	All Ex Ante Top-Down Scenarios	
			Per Participant Hourly kWh/h	Aggregate Hourly MWh/h
All	All	1,582	74.0	117
Size	Under 20 kW	297	11.8	3.5
	20 kW to 199.99 kW	938	43.3	40.6
	200 kW or Greater	346	210.6	72.9
NAICS Desc	Agriculture, Mining & Construction	983	72.5	71.3
	Institutional/Government	40	168.4	6.7
	Manufacturing	28	401.1	11.2
	Offices, Hotels, Finance, Services	435	47.9	20.8
	Retail Stores	19	45.3	0.9
	Schools	--	--	--
	Wholesale, Transport, Other Utilities	77	78.3	6.0
LCA	Greater Bay Area	419	75.0	31.4
	Greater Fresno Area	316	54.4	17.2
	Humboldt	43	34.4	1.5
	Kern	4	2,112.5	8.4
	North Coast and North Bay	122	18.5	2.3
	Other	80	563.6	45.1
	Sierra	32	253.3	8.1
	Stockton	565	5.3	3.0

5.1.2 Bottom-Up

The bottom-up ex ante impacts are derived from weather normalized impacts. These weather-normalized impacts are then weighted to account for the appropriate distributions of ELRP Group A.1 participants based on the forecasted participant counts. More specifically, participants are weighted based on the forecasted distributions of NAICS description, customer size, and SubLAP. Additionally, these impacts are increased by 20% to account for the increase in incentives between 2021 and 2022 and segments of NAICS description, customer size and SubLAP that had negative load impacts (load increases) were manually set to zero. It should be noted that the four A.1 BIP participants were removed from this analysis due to limited participation in the ELRP and no incentivized event participation outside of the July 9th event. Note that the full details on the ex ante impacts are included in the ex ante table generators.

Table 5-2 and Table 5-3 present the average per participant kWh and aggregate MW impacts for the bottom-up weather scenarios under utility August system peak and utility typical event day weather scenarios (respectively). As seen, the average ex ante impacts are lower than the average event day impacts of [redacted] kWh/h, ranging from 10.6 to 12.4 kWh/h for the overall population. When comparing these scenarios to ex post impacts, it is important to keep in mind that 2021 event average temperatures were higher than the temperatures in each given weather scenario and that ex ante impacts includes June 17th event participation (which is excluded from the ex post average event day).

TABLE 5-2: PY 2022 PG&E GROUP A.1 AVERAGE PER PARTICIPANT BOTTOM-UP EX ANTE IMPACTS BY CUSTOMER SIZE, NAICS DESCRIPTION AND LCA – MONTH OF AUGUST

Group	Segment	Ex Post - Per Customer Impact (kWh/h)	Utility Aug. System Peak (kWh/h)		Utility Typical Event (kWh/h)	
			1-in-10	1-in-2	1-in-10	1-in-2
All	All	[redacted]	11.9	10.6	12.4	10.7
Size	Under 20 kW	0.0	0.6	0.6	0.6	0.6
	20 kW to 199.99 kW	0.0	3.6	3.1	3.9	3.2
	200 kW or Greater	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Industry	Agriculture, Mining & Construction	[redacted]	3.4	3.3	3.4	3.4
	Institutional/Government	[redacted]	125.1	118.9	119.0	113.8
	Manufacturing	[redacted]	118.2	112.7	119.8	113.8
	Offices, Hotels, Finance, Services	[redacted]	15.7	12.0	17.9	12.8
	Retail Stores	[redacted]	0.4	0.3	0.4	0.3
	Schools	[redacted]	--	--	--	
	Wholesale, Transport, Other Utilities	[redacted]	5.2	4.9	5.3	5.0
LCA	Greater Bay Area	[redacted]	19.3	15.5	21.5	16.3
	Greater Fresno Area	[redacted]	9.2	8.8	9.1	8.7
	Humboldt	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Kern	1.7	2.8	2.6	2.8	2.6
	North Coast and North Bay	[redacted]	7.7	7.4	7.8	7.5
	Other	[redacted]	4.3	4.1	4.2	4.1
	Sierra	[redacted]	122.7	117.9	118.6	115.0
	Stockton	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unknown	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Because the PG&E participant forecast is the same for all years (2022-2025), the MW forecast is same for all years as well. As seen in Table 5-3, the total bottom-up MW forecast ranges from 16.8 to 19.6 MW depending on the weather scenario.

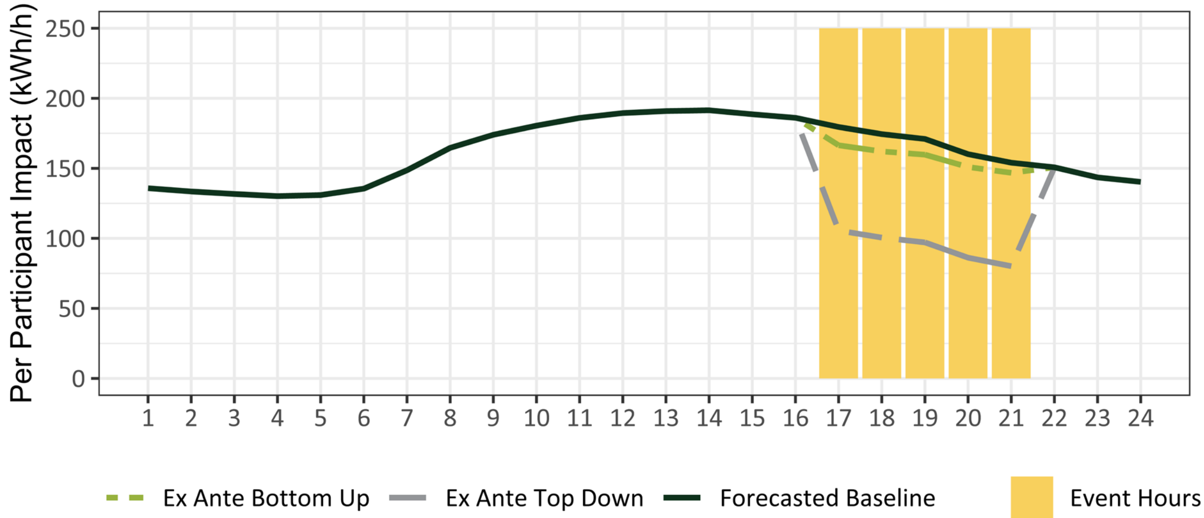
TABLE 5-3: PY 2022 GROUP A.1 AVERAGE AGGREGATE BOTTOM-UP EX ANTE IMPACTS BY NAICS DESCRIPTION AND CUSTOMER SIZE

Group	Segment	PY 2022 Forecasted Enrollment	Utility Aug. System Peak (MWh/h)		Utility Typical Event (MWh/h)	
			1-in-10	1-in-2	1-in-10	1-in-2
All	All	1,582	18.9	16.8	19.6	16.9
Size	Under 20 kW	297	0.2	0.2	0.2	0.2
	20 kW to 199.99 kW	938	3.4	2.9	3.6	3.0
	200 kW or Greater	346	[redacted]	[redacted]	[redacted]	[redacted]
Industry	Agriculture, Mining & Construction	983	3.4	3.3	3.3	3.3
	Institutional/Government	40	5.0	4.8	4.8	4.6
	Manufacturing	28	[redacted]	[redacted]	[redacted]	[redacted]
	Offices, Hotels, Finance, Services	434	6.8	5.2	7.8	5.5
	Retail Stores	19	0.0	0.0	0.0	0.0
	Wholesale, Transport, Other Utilities	77	0.4	0.4	0.4	0.4
LCA	Greater Bay Area	418	8.1	6.5	9.0	6.8
	Greater Fresno Area	316	2.9	2.8	2.9	2.8
	Humboldt	4	[redacted]	[redacted]	[redacted]	[redacted]
	Kern	122	0.3	0.3	0.3	0.3
	North Coast and North Bay	43	0.3	0.3	0.3	0.3
	Other	639	2.4	2.3	2.4	2.3
	Sierra	32	3.9	3.7	3.8	3.7
	Stockton	80	[redacted]	[redacted]	[redacted]	[redacted]
	Unknown	1	[redacted]	[redacted]	[redacted]	[redacted]

5.1.3 Top-Down Vs Bottom-Up

There is a substantial difference between the bottom-up and top-down ex ante impact estimates. For example, the bottom-up 1-in-2 August system peak is only 14.9% of the top-down ex ante impact, as shown in Figure 5-1. This results in a large gap between ex ante impacts based on how participants preformed performed in 2021 versus what participants stated they can provide in 2022.

FIGURE 5-1: PG&E GROUP A.1 TOP-DOWN VS. BOTTOM-UP 1-IN-2 AUGUST UTILITY SYSTEM PEAK EVENT DAY



There have been several changes to the ELRP between the 2021 and 2022 event seasons. One way to view the top-down and bottom-up ex ante impacts is through the lens of these changes. The bottom-up estimates present a view of A.1 participants that participate similarly to 2021. Conversely, the top-down impacts represent the potential of the ELRP and demonstrates what participants are capable of should they if sufficiently motivated to achieve their nominated levels of curtailment. The extent to which the program changes result in this latter scenario is the key question.

5.2 SCE EX ANTE IMPACTS

5.2.1 Top-Down

The top-down approach for estimating ex post impacts takes the MW and participant forecast, divides impacts into the respective participant segments and takes the total MW forecast as the truth for aggregate impacts of A.1 participants. The average participant impact is the total MW divided by the number of participants in the population. As a result, the 2022 top-down ex ante impacts are 54.9 MW in aggregate with a 260.0 per participant kWh/h impact. Given that these impacts are not weather normalized, the ex ante impacts are the same under all 1-in-2 and 1-in-10 weather scenarios.

Table 5-4, below, presents the top down forecasted top-down impacts by various segments. As seen, the “Institutional and Government” and “Agriculture, Mining & Construction” are expected to provide the majority of PY 2022 impacts based on MW forecasts.

TABLE 5-4: PY 2022 SCE GROUP A.1 TOP DOWN EX ANTE MW FORECAST BY CUSTOMER SIZE, NAICS DESCRIPTION AND LCA

Group	Segment	PY 2022 Forecasted Enrollment	All Ex Ante Top-Down Scenarios	
			Per Participant Hourly kWh/h	Aggregate Hourly MWh/h
All	All	211	260.0	54.9
Size	Below 250 kW	50	85.3	4.3
	250 or more kW	156	320.9	50.1
	Unknown	5	103.6	0.5
NAICS Description	Agriculture, Mining & Construction	66	150.2	9.9
	Institutional and Government	22	911.1	20.0
	Manufacturing	30	177.2	5.3
	Offices, Hotels, Finance, Services	23	58.4	1.3
	Other	43	194.5	8.4
	Retail Stores	6	299.5	1.8
	Schools	13	152.1	2.0
	Wholesale, Transport, Other Utilities	7	870.6	6.1
LCA	Big Creek/Ventura	71	133.3	9.5
	LA Basin	140	324.2	45.4

5.2.2 Bottom-Up

The bottom-up ex ante impacts are derived from weather normalized impacts. These weather normalized impacts are then weighted to account for the appropriated distributions of ELRP A.1 participants based on enrolled participant characteristics as of March 15th, 2022. More specifically, participants are weighted based on the distribution NAICS description, customer size and SubLAP. Additionally, these impacts are increased by 20% to account for the increase in incentives between 2021 and 2022. Segments that had negative load impacts (load increases) were manually set to zero. Note that the full details on the ex ante impacts are included in the ex ante table generators.

For SCE, Table 5-5 and Table 5-6 present the average per participant kWh and aggregate MW impacts for the bottom-up ex ante approach. The impacts shown are for the utility August system peak and utility typical event day weather scenarios. The average ex ante impacts are higher than the average event day impacts of [redacted] kWh/h, ranging from 32.9 kWh/h to 36.7 kWh/h for the overall population.

TABLE 5-5: SCE GROUP A.1 AVERAGE PER PARTICIPANT BOTTOM-UP EX ANTE IMPACTS BY CUSTOMER SIZE, NAICS DESCRIPTION AND LCA

Group	Segment	Ex Post - Per Customer Impact* (kWh/h)	Utility Aug. System Peak (kWh/h)		Utility Typical Event (kWh/h)	
			1-in-10	1-in-2	1-in-10	1-in-2
All	All	[redacted]	35.9	34.0	36.7	32.9
Size	Below 250 kW	[redacted]	9.1	7.9	9.5	7.4
	250 kW or Greater	[redacted]	44.1	41.9	45.0	40.5
	Unknown	[redacted]	49.7	49.6	49.7	49.4
NAICS Description	Agriculture, Mining & Construction	[redacted]	18.9	19.7	19.3	18.7
	Institutional and Government	[redacted]	55.6	54.7	55.5	53.1
	Manufacturing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Offices, Hotels, Finance, Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Other	[redacted]	46.9	36.9	50.1	33.5
	Retail Stores	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Schools	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Wholesale, Transport, Other Utilities	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LCA	Big Creek/Ventura	[redacted]	21.6	21.8	22.1	20.7
	LA Basin	[redacted]	43.2	40.2	44.0	39.0

*Excluding non-performers

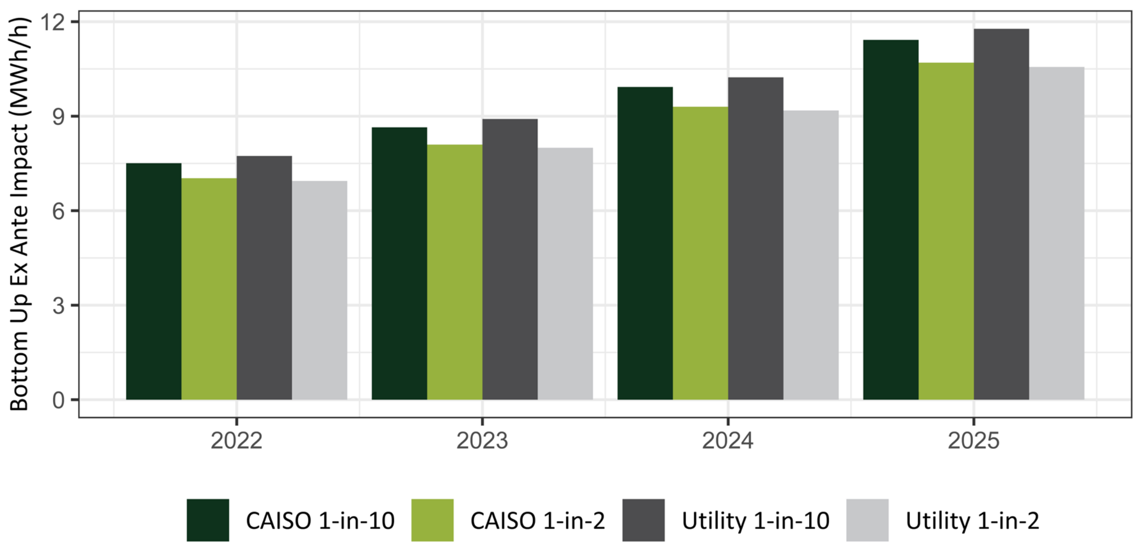
As seen in Table 5-6, the total bottom-up 2022 MW ex ante impact ranges from 6.9 to 7.7 MW depending on the weather scenario.

TABLE 5-6: SCE GROUP A.1 PY 2022 AVERAGE AGGREGATE MW BOTTOM-UP EX ANTE IMPACTS BY CUSTOMER SIZE, NAICS DESCRIPTION AND LCA

Group	Segment	PY 2022 Forecasted Enrollment	Utility Aug. System Peak (MWh/h)		Utility Typical Event (MWh/h)	
			1-in-10	1-in-2	1-in-10	1-in-2
All	All	211	7.6	7.2	7.7	6.9
Size	Below 250 kW	50	0.5	0.4	0.5	0.4
	250 kW or Greater	156	6.9	6.5	7.0	6.3
	Unknown	5	0.2	0.2	0.2	0.2
NAICS Description	Agriculture, Mining & Construction	66	1.2	1.3	1.3	1.2
	Institutional and Government	22	1.2	1.2	1.2	1.2
	Manufacturing	30	[redacted]	[redacted]	[redacted]	[redacted]
	Offices, Hotels, Finance, Services	23	[redacted]	[redacted]	[redacted]	[redacted]
	Other	43	2.0	1.6	2.1	1.4
	Retail Stores	6	[redacted]	[redacted]	[redacted]	[redacted]
	Schools	13	[redacted]	[redacted]	[redacted]	[redacted]
	Wholesale, Transport, Other Utilities	7	[redacted]	[redacted]	[redacted]	[redacted]
LCA	Big Creek/Ventura	71	1.5	1.6	1.5	1.5
	LA Basin	140	6.1	6.2	5.6	5.5

Unlike PG&E, SCE is expecting roughly 15% year over year growth. Figure 5-2 presents this growth visually. As seen, the bottom-up ex ante impacts for 2025 reach up to 11.8 MW inter the utility 1-in-10 weather scenario.

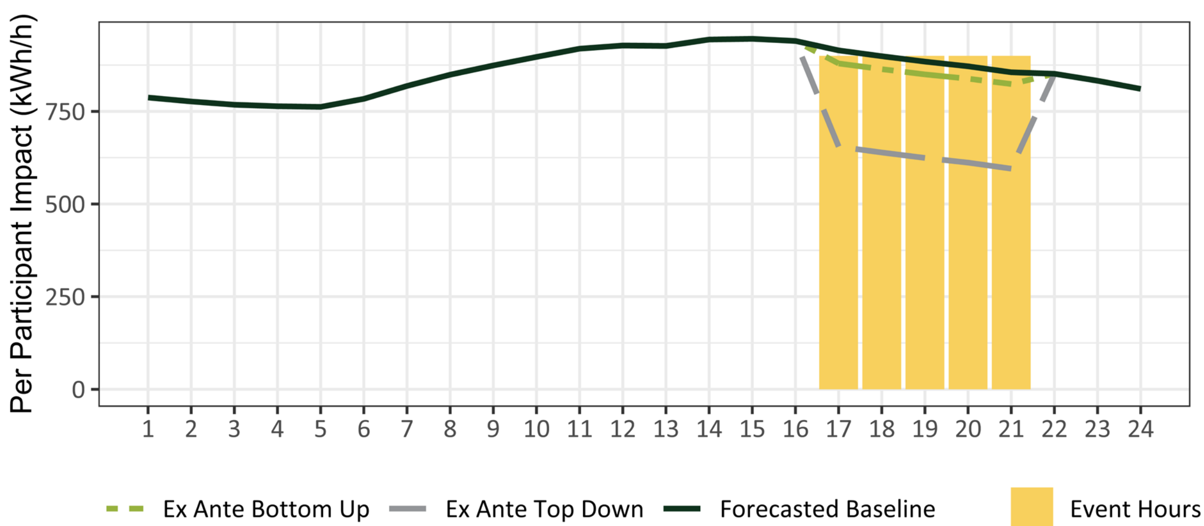
FIGURE 5-2: SCE GROUP A.1 BOTTOM-UP EX ANTE MW FORECAST BY YEAR AND WEATHER SCENARIO



5.2.3 Top-Down Vs Bottom-Up

There is a stark difference between the bottom-up and top-down ex ante impact estimates. For example, the bottom-up 1-in-2 August system peak is less than 14% of the top-down ex ante impact, as demonstrated in Figure 5-3. This results in a large gap between how participants performed in 2021 versus what the load reduction participants stated they can provide in 2022.

FIGURE 5-3: SCE GROUP A.1 TOP-DOWN VS. BOTTOM-UP 1-IN-2 AUGUST UTILITY SYSTEM PEAK EVENT DAY



There were a number of changes to the ELRP that were made between the 2021 and 2022 event seasons. One way to view the top-down and bottom-up ex ante impacts is through this lens of change. The bottom-up estimates present a view of A.1 participants that largely participate as they had in 2021. Conversely, the top-down impacts represent the potential of the ELRP and demonstrates what participants are capable of if sufficiently motivated through the ELRP program changes and achieve their nominated levels of curtailment.

6 EX POST AND EX ANTE COMPARISONS

The section presents comparisons between ex post and ex ante impacts. The Request for Proposal (RFP) and Load Impact Protocols call for the following comparisons:

1) How the current ex post results differ from the prior year’s ex post results;
2) How the current ex post results differ from last year’s forecast;
3) How the current ex ante results differ from the prior year's forecast; and
4) How the current ex ante results differ from the current ex post results

Given that PY 2021 is the first year of the ELRP, comparison between the current year and prior year are not possible for this reporting cycle. As a result, only comparisons between PY 2021 ex ante and ex post are examined.

6.1 PG&E CURRENT EX POST AND CURRENT EX ANTE COMPARISONS

Table 6-1 presents comparisons between the ex post impacts and ex ante impacts on the typical event day under utility 1-in-2 and 1-in-10 weather conditions. As seen the bottom ex ante impacts present a lower per customer load reduction compared to the ex post average event day. However, the forecasted baselines are lower as well, which results in slightly larger percentages of load reductions in the bottom-up ex ante impacts with the ex post results. Not surprisingly, the top-down ex ante impacts represent roughly a sixfold increase in relative and per-participant load reductions savings compared to both the ex post and bottom-up ex ante impacts.

TABLE 6-1: PG&E CURRENT EX POST VS EX ANTE COMPARISONS TYPICAL EVENT DAY

Analysis	Utility Weather Year	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Customer Impact (kWh/h)	Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
PY 2021 Ex Post	--	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PY 2022 Ex Ante - Bottom-Up	1-in-10	1,582	171.3	12.4	7.2%	19.6	96.2
	1-in-2	1,582	168.1	10.7	6.4%	16.9	93.5
PY 2022 Ex Ante -Top-Down	1-in-10	1,582	171.3	74.0	43.1%	117.0	96.2
	1-in-2	1,582	168.1	74.0	44.0%	117.0	93.5

6.1.1 Factors Attributing to Differences Between Current Ex Post and Ex Ante Impacts – PG&E

A number of factors contributed to the difference between ex post and ex ante impacts estimates. These differences are described below.

PG&E Ex Post vs. Bottom-Up and Top-Down Ex Ante

- **Enrollment**: There were, on average, 676 participants that participated in the ELRP on the average event day. PG&E is forecasting 1,582 Group A.1 participants for PY 2022. While this does not affect the per participant impact estimation, the net effect is an increase in aggregate load reductions in the ex ante impacts compared to the ex post analysis. Additionally, the distribution of enrollment forecast characteristics is slightly different from the actual participant characteristics in PY 2021. As a result, there are differences in the underlying weights of ex ante per participant impacts and reference loads.

- **COVID-19:** Verdant identified that three NAICS categories that continue to exhibit COVID-19 related impacts on load shapes. Only two of these categories are included in the ex ante participant forecast; Institutional/Government" and "Offices, Hotels, Finance, Services". As a result, these NAICS groups receive baseline adjustments in each month and year, representing subsiding COVID-19 effects overtime. Adjustment factors are only applied to the reference loads and not to impacts. Given that PY 2021 was the first year of the ELRP, there is no frame of reference for how the lingering pandemic influenced ELRP impacts.

- **Weather:** PG&E ELRP participants experienced extreme weather on July 9th and July 10th, with average temperatures exceeding 100 degrees Fahrenheit. Temperatures that are included in the ex ante weather scenarios are lower on average than those experienced by the PG&E participant population on average. As a result, weather normalized impacts are expected to be lower for weather sensitive participants in the bottom-up forecast compared to the ex post average event day impacts. Additionally, this this has the effect of lowering weather-sensitive participant reference loads.

PG&E Ex Post vs. Bottom-Up Ex Ante

- **Event Days:** The average event day impacts in the ex post analysis exclude impacts form June 17th**,** however, these impacts are included in the ex ante bottom-up analysis. This only impacts the 30 PG&E Group A.1 participants (16 modeled) who participated on that event day and is likely has minor impacts on the overall ex ante analysis.

- **Increased Incentives**: The ELRP has increased its incentives from $1 per kWh to $2 per kWh of load reduction (starting in PY 2022). To account for this, weather normalized impacts were increased by 20% and negative load reductions were set to zero. This has the effect of increasing the per participant load impacts overall compared to the evaluated weather normalized impacts.

- **Methods:** The ex post impact methodology utilizes panel models with matched control groups and individual, customer specific regression models. Additionally, the ex post models estimated impacts for weekend and weekday models separately. To produce a single ex ante impact coefficient that includes weekday and weekend event impacts, the ex post analysis was modified to incorporate both weekend and weekday data into modeling and model specifications were adjusted to control for weekend effects on modeled load. Additionally, the matched control groups were design for estimation of weekday impacts only. As a result, the ex ante models rely solely on customer-specific models. Section 3.4.2 provides further details on how ex post models were altered for the ex ante analysis

PG&E Ex Post vs. Top-Down Ex Ante

- **Methods:** The ex post analysis has no bearing in the top-down ex ante impacts. The top-down impacts rely on participant stated nominations. As a result, the top-down ex ante impacts are substantially higher than the PY 2021 ex post impacts and bottom-up ex ante impacts.

6.2 SCE CURRENT EX POST AND CURRENT EX ANTE COMPARISONS

Table 6-2 presents comparisons between the ex post impacts (with and without non-participants) and ex ante impacts on the typical event day under utility 1-in-2 and 1-in-10 weather conditions. As seen, the ex post impacts are presented with and without the designated non-performers as ex ante impacts exclude these participants. As seen, the relative bottom-up load reduction increased compared to the ex post load reductions. However, the relative load reduction and per participant load reductions are roughly ten times greater under the top-down ex ante impacts compared with the bottom-up load reductions.

TABLE 6-2: SCE CURRENT EX POST VS EX ANTE COMPARISONS TYPICAL EVENT DAY

Analysis	Weather Year	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Customer Impact (kWh/h)	Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
PY 2021 Ex Post - With Non-Participants	--	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PY 2021 Ex Post - Without Non-Participants	--	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PY 2022 Ex Ante - Bottom-Up	1-in-10	211	892.9	36.7	4.1%	7.7	93.7
	1-in-2	211	880.8	32.9	3.7%	6.9	86.0
PY 2022 Ex Ante -Top-Down	1-in-10	211	892.9	260	29.1%	54.9	93.7
	1-in-2	211	880.8	260	29.5%	54.9	86.0

6.2.1 Factors Attributing to Differences Between Current Ex Post and Ex Ante Impacts – SCE

A number of factors contributed to the difference between ex post and ex ante impacts estimates. These differences are described below.

SCE Ex Post vs. Bottom-Up and Top-Down Ex Ante

- **Enrollment**: There were, on average, 36 participants that participated in the ELRP on the average event day in PY 2021. SCE is forecasting 211 Group A.1 participants for PY 2022. While this does not affect the per participant impact estimation, the net effect is an increase in aggregate ex ante load compared to the ex post analysis. Additionally, the distribution of enrolled participant characteristics as of March 15, 2022 varied from the actual participant characteristics in PY 2021. As a result, there are differences in the underlying weights of ex ante per participant impacts and reference loads.

- **COVID-19:** Verdant identified that three NAICS categories that continue to exhibit COVID-19 related impacts on load shapes; “Institutional/Government”, “Offices, Hotels, Finance, Services” and “Schools”. As a result, these NAICS groups receive baseline adjustments in each month and year, representing subsiding COVID-19 effects overtime. Adjustment factors are only applied to the reference loads and not to ex ante impacts. Given that PY 2021 was the first year of the ELRP, there is no frame of reference for how the lingering pandemic influenced ELRP impacts.

- **Weather:** SCE typical event day 1-in-10 impacts represent event day conditions that are hotter compared with average event day conditions in PY 2021. As a results weather normalized impacts and reference loads are increased relative to the ex post impacts.

- **Removal of Non-Performers:** The ex ante impact analysis removed two SCE participants that were considered to be “non-performers” and were the primary participants responsible for ex post load increases (described in Section 4.2.2). This has the effect of lowering the ex ante reference load but increasing per customer ex ante impacts.

SCE Ex Post vs. Bottom-Up Ex Ante

- **Increased Incentives**: The ELRP has increased its incentives from $1 per kW to $2 per kW of load reduction (starting in PY 2022). To account for this, weather-normalized impacts were increased by 20% and negative load reductions were set to zero. This has the effect of increasing the per participant load impacts overall compared to the evaluated weather normalized impacts.

- **Methods:** The ex post impact methodology estimated impacts for weekend and weekday models separately. To produce a single ex ante impact coefficient that includes weekday and weekend event impacts, the ex post analysis was modified to incorporate both weekend and weekday data into modeling and model specifications were adjusted to control for weekend effects on modeled load. Section 3.4.2 provides further details on how ex post models were altered for the ex ante analysis.

SCE Ex Post vs. Top-Down Ex Ante

- **Methods:** The ex post analysis has no bearing in the top-down ex ante impacts. The top-down impacts rely on participant stated nominations. As a result, the top-down ex ante impacts are substantially higher than the PY 2021 ex post impacts and bottom-up ex ante impacts.

7 FINDINGS AND RECOMMENDATIONS

This section presents the findings and recommendations from the PY 2021 PG&E and SCE ELRP Load Impact Evaluation. As stated in the introduction, various modifications to the program have already been introduced for PY 2022. As a result, some findings and recommendations may echo changes that are already underway.

- **Finding 1**: Dually enrolled participants in Groups A.1 and Groups A.2, for both PG&E and SCE, did not provide load reductions, on average, during PY 2021 ELRP events. Participants dually enrolled in the ELRP and BIP curtailed their load during BIP event hours on July 9th but did not start their curtailments until the initiation of the BIP event, ignoring the first hour of the ELRP event. (This is not surprising given that dually enrolled BIP participants are only compensated for participation during overlapping BIP and ELRP event hours.) Further, there were no additional load reductions that could be attributed to the ELRP during overlapping event hours. In theory, load reduction beyond BIP FSL commitments could be attributed to the ELRP. However, there is no evidence for additional load reductions beyond FSL commitments.

  While dually enrolled BIP participants are not compensated for load reductions outside of the ELRP, dually enrolled BIP customers in Group A.1 and BIP aggregators in Group A.2 were notified of all ELRP events. In essence, all BIP participants are notified for voluntary ELRP events. In theory participants could still curtail their loads through altruistic motivations. For this reason, the evaluation considered all BIP participants as active participants for all events. However, there is no evidence of load reductions, on average, from these participants on ELRP event days. In fact, dual enrollment in BIP appears to have been detrimental to the overall load reductions on the SCE July 10th event, the day following the July 9th BIP event day. One SCE dually enrolled BIP participant, who fully dispatched for the BIP event remained “offline” until the following morning and had significant snapback during the July 10th ELRP event window, increasing their load by multiple MW over the baseline and negating other participant load reductions.

  - **Recommendation 1**: Dual enrollment is a cornerstone of the ELRP. However, evidence suggests that dually enrolled BIP participants do not provide additional load impacts on days where both BIP and ELRP resources are dispatched. It is likely that BIP participants are largely concerned with achieving their FSL commitments to avoid BIP related financial penalties and not enticed by ELRP participation. The evaluation team recommends that dually enrolled participant curtailments should not be relied upon for event days where they are dispatched for other programs. For many BIP customers, it is likely that FSL commitments already make up the lion share of their available curtailable load. Additionally, the program managers and implementors should continue to engage with dually enrolled participants and aggregators to find ways that will make the dually enrolled participants more reliable ELRP resources. A common concern heard by PG&E’s program implementor from BIP customers was that participants dually enrolled in BIP and ELRP are not able to receive compensation outside of overlapping event hours. While this evaluation is not intended to be a process evaluation, BIP participants may become more reliable ELRP resources if their participation was compensated for event hours outside of overlapping BIP event hours.

- **Finding 2**: ELRP participant nominations were overstated compared with evaluated ex post load reductions. Given that the ELRP provides incentives for load reductions without any penalties for missing stated load reductions, there is no mechanism in the ELRP that holds participants to their stated nominations.

  - **Recommendation 2**: Participant nominations are a useful way of understanding the how much curtailable load is available as a DR resource. However, the program design of the ELRP does not hold participants accountable for nominated load reductions. Program managers should to track how settlement load reductions compare with ELRP participants stated nominations over the course of the ELRP event season to help inform expectations of load reductions for upcoming events. The program has increased incentives from $1 per kWh to $2 per kWh in load reductions which may make participants more reliable DR resources.

- **Finding 3**: $1 per kWh is not enough of an incentive to keep participants consistently engaged in the program. The last event day of the season (July 29th) saw the lowest performance among all events in PY 2021 for both PG&E and SCE.

  - **Recommendation 3**: The program has already increased the incentive to $2 per kWh. The program should continue to closely monitor performance in 2022 events.

- **Finding 4:** PG&E ELRP Group A.1 participants provided and average of [redacted] MW of load reduction per event hour during PY2021. However, PG&E Group A.2 participants provided virtually zero load reductions per event hour ([redacted] MW per average event hour) and SCE Group A.1 participant increased their load on average during ELRP events, representing [redacted] MW of load reductions for the average event hour.

  - **Recommendation 4**: There are several substantial changes to the ELRP that take effect for PY 2022. The program staff should monitor the impacts of these changes for the 2022 event season and continue to identify areas to improve program performance.

- **Finding 5:** All PY 2021 events were called under day-of notification. Event day load reduction for day-ahead notifications may more closely align with participant stated ELRP nominations as participants have the extra time to prepare for necessary changes to operations schedules.

  - **Recommendation 5**: The PY2022 ELRP should have at least one event utilizing the day ahead notification to test whether there is a difference in load reductions for day-of and day -ahead event participation.

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APPENDIX A TABLE GENERATORS

One of the key deliverables is the table generators, which are Excel files that allow interested stakeholders to observe the impacts for varying domains of interest, including industry type, size, event day or weather scenario. These are provided in the following separate files:

- Appendix A-1 PG&E PY2021 ELRP Ex Post Table Generator PUBLIC.xlsx
- Appendix A-2 PG&E PY2021 ELRP Ex Ante Table Generator PUBLIC.xlsx
- Appendix A-3 SCE PY2021 ELRP Ex Post Table Generator PUBLIC.xlsx
- Appendix A-4 SCE PY2021 ELRP Ex Ante Table Generator PUBLIC.xlsx

APPENDIX B EX POST EVENT DAY LOAD IMPACTS

Event day hourly profiles by utility, group, and event day are presented in Figure B-1 through Figure B-11. These figures show the observed load, estimated baselines, and corresponding impacts over the 24 hours, with the event hours indicated by the shaded bars.

B.1 GROUP A.1 PG&E EVENT DAY IMPACTS

FIGURE B-1: PG&E A.1 JUNE 17TH EVENT DAY LOAD

[redacted]

FIGURE B-2: PG&E A.1 JULY 9TH EVENT DAY LOAD

[redacted]

FIGURE B-3: PG&E A.1 JULY 10TH EVENT DAY LOAD

[redacted]

FIGURE B-4: PG&E A.1 JULY 29TH EVENT DAY LOAD

[redacted]

B.2 GROUP A.2 PG&E EVENT DAY IMPACTS

FIGURE B-5: PG&E A.2 JUNE 17TH EVENT DAY LOAD

[redacted]

FIGURE B-6: PG&E A.2 JULY 9TH EVENT DAY LOAD

[redacted]

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FIGURE B-7: PG&E A.2 JULY 10TH EVENT DAY LOAD

[redacted]

FIGURE B-8: PG&E A.2 JULY 29TH EVENT DAY LOAD

[redacted]

B.3 SCE EVENT DAY IMPACTS

FIGURE B-9: SCE A.1 JULY 9TH EVENT DAY LOAD

[redacted]

FIGURE B-10: SCE A.1 JULY 10TH EVENT DAY LOAD

[redacted]

FIGURE B-11: SCE A.1 JULY 29TH EVENT DAY LOAD

[redacted]

APPENDIX C PROXY DAY TESTING PERFORMANCE

The selection of models for each participant was based on assessing performance on a set of proxy event days, which are non-event days that have event-like weather conditions. The assessment of these different models is concerned primarily with accuracy and precision. Accuracy represents how closely on average the calculated baseline matches the observed load. A component of measuring accuracy is bias, which indicates the extent to which the calculated baseline over or underestimates the load. In contrast, precision indicates how reliably a baseline is close to the observed load. It is possible to have a model that on average is highly accurate with very poor precision, such as when a method both under and over predicts by substantial amounts with regularity. Likewise, it is possible to have a method that is very precise but highly inaccurate, such as when a model over or underestimates the load with high consistency. Of course, a baseline can also be neither accurate nor precise.

The primary metrics for accuracy and precision in this analysis are Normalized Mean Bias Error (NMBE) and Normalized Mean Absolute Error (NMAE), respectively. Other assessments of baselines have often used the Mean Percent Error (MPE) as the metric to assess accuracy and the Mean Absolute Percent Error (MAPE) and Coefficient of Variation of the Root Mean Square Error (CVRMSE) as the metrics for precision.

The preference for these metrics was based primarily on a shortcoming of the MAPE and MPE when it comes dealing with observed values of zero, which will result in division by zero error and the loss of the data point. presents descriptions and the equations for two metrics calculated for accuracy and the three calculated for precision. One thing to note is that for the NMBE and NMAE, the formulas go against a convention seen in some contexts (e.g., ASHRAE), where the error is calculated as the baseline minus the observed. This runs contrary to the more typical conventions of calculating MPE and MAPE, so for the sake of consistent interpretation of the NMBE and MPE, where negative values indicate overestimation of the baseline, Verdant has calculated the error as the observed load minus the calculated baseline for all metrics.

TABLE C-1: DESCRIPTIONS AND EQUATIONS FOR PERFORMANCE METRICS

Metric Type	Metric	Description	Equation
Accuracy/Bias	Mean Percent Error (MPE)	Represents the average of the errors in the calculated baselines as a percentage of the observed load.	$MPE = \frac{1}{n}\sum_{i=1}^{n}\frac{y_i - \hat{y}_i}{y_i}$
	Normalized Mean Bias Error (NMBE)	Represents the normalized average bias in the calculated baselines.	$NMBE = \frac{\frac{1}{n}\sum_{i=1}^{n}(y_i - \hat{y}_i)}{\bar{y}}$
Precision	Mean Absolute Percent Error	Represents the average of the absolute errors in the calculated baselines as a percentage of the observed load.	$MAPE = \frac{1}{n}\sum_{i=1}^{n}\left\lvert\frac{y_i - \hat{y}_i}{y_i}\right\rvert$
	Normalized Mean Absolute Error (NMAE)	Represents that average of the normalized absolute error in the calculated baselines.	$NMAE = \frac{\frac{1}{n}\sum_{i=1}^{n}(\lvert y_i - \hat{y}_i\rvert)}{\bar{y}}$
	Coefficient of Variation of the Root Mean Squared Errors CV(RMSE)	Represents the normalized average of the squared errors between the observed load and calculated baselines.	$CV(RMSE) = \frac{\sqrt{\frac{1}{n}\sum_{i=1}^{n}(y_i - \hat{y}_i)^2}}{\bar{y}}$

Table C-2 through Table C-6 present summaries of the model performance metrics for PG&E and SCE for both weekdays and weekends. Overall, the models have good performance, with some expected variability based on industry type. The more industrial participants have poorer model performance, which is expected given the volatile load associated with many of these customers. In contrast, office and retail customers, which have more consistent occupancy and operations as well as weather-sensitivity, have the best performance metrics.

C.1 PERFORMANCE METRICS

TABLE C-2: SPECIFICATION TEST RESULTS FOR THE EX-POST ANALYSIS - PG&E WEEKDAY

NAICS	Num. of Service Points	CV RMSE	NMBE	NMAE	Adjusted R^2
Agriculture, Mining, and Construction	475	0.301	0.091	0.234	0.738
Institutional/Government	9	0.008	0.000	0.006	0.817
Manufacturing	43	0.014	0.002	0.011	0.743
Offices, Hotels, Finances, and Services	190	0.005	0.001	0.003	0.911
Retail Stores	12	0.003	0.000	0.002	0.959
Schools	3	0.002	0.001	0.002	0.929
Wholesale, Transport, Other Utilities	64	0.021	0.004	0.015	0.712

TABLE C-3: SPECIFICATION TEST RESULTS FOR THE EX-POST ANALYSIS - PG&E WEEKEND

NAICS	Num. of Service Points	CV RMSE	NMBE	NMAE	Adjusted R^2
Agriculture, Mining, and Construction	475	0.663	0.190	0.518	0.734
Institutional/Government	9	0.011	-0.001	0.008	0.807
Manufacturing	41	0.028	0.002	0.021	0.798
Offices, Hotels, Finances, and Services	181	0.007	0.001	0.005	0.912
Retail Stores	12	0.005	0.001	0.003	0.936
Schools	3	0.005	0.000	0.004	0.903
Wholesale, Transport, Other Utilities	64	0.040	0.002	0.027	0.703

TABLE C-4: SPECIFICATION TEST RESULTS FOR THE EX-POST ANALYSIS - PG&E PANEL DATA

NAICS	Num. of Service Points	CV RMSE	NMBE	NMAE	Adjusted R^2
Offices, Hotels, Finances, and Services	181	0.001	0.000	0.000	0.936
Retail Stores	12	0.001	0.000	0.000	0.936
Wholesale, Transport, Other Utilities	64	0.001	0.000	0.000	0.936

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TABLE C-5: SPECIFICATION TEST RESULTS FOR THE EX-POST ANALYSIS - SCE WEEKDAY

NAICS	Num. of Customers	CV RMSE	NMBE	NMAE	Adjusted R^2
Agriculture, Mining, and Construction	10	0.017	-0.001	0.012	0.664
Institutional/Government	9	0.003	0.000	0.002	0.933
Manufacturing	5	0.003	0.000	0.002	0.838
Offices, Hotels, Finances, and Services	2	0.002	0.000	0.002	0.900
Retail Stores	2	0.002	0.000	0.001	0.929
Schools	1	0.013	-0.003	0.010	0.899
Wholesale, Transport, Other Utilities	5	0.011	0.003	0.008	0.710
Other	5	0.006	-0.001	0.004	0.935

TABLE C-6: SPECIFICATION TEST RESULTS FOR THE EX-POST ANALYSIS: SCE WEEKENDS

NAICS	Num. of Customers	CV RMSE	NMBE	NMAE	Adjusted R^2
Agriculture, Mining, and Construction	10	0.034	0.010	0.026	0.665
Institutional/Government	9	0.003	0.000	0.002	0.922
Manufacturing	5	0.006	0.002	0.004	0.817
Offices, Hotels, Finances, and Services	2	0.003	0.000	0.002	0.911
Retail Stores	2	0.003	0.000	0.002	0.962
Schools	1	0.019	0.008	0.015	0.920
Wholesale, Transport, Other Utilities	5	0.009	0.000	0.007	0.718
Other	5	0.004	0.000	0.003	0.924

C.2 ACTUAL VS PREDICTED PROXY DAY LOAD SHAPES

C.2.1 Ex Post Models

As a means of visually assessing how well the statistical models predicted usage, Figure C-1 through Figure C-8 shows the average actual and predicted load on weekday and weekend proxy event days for PG&E and SCE. Figure C-1, Figure C-3, Figure C-5, and Figure C-7 show the average profiles for all accounts, which offer an overall perspective on how well the models work. To better understand the underlying variability, Figure C-2, Figure C-4, Figure C-6, and Figure C-8 show the profiles broken out based on the final type of model specification selected. While these plots speak for themselves, there are some observations worth discussing. The first is that in the aggregate, the models produce estimated load that is very close to the actual consumption. In a few cases where there are more marked discrepancies, they are not in the later hours when events occur.

A second observation is that there are clear differences among the model types. For example, in Figure C-2, the weather-sensitive models for both NEM and Non-NEM do not align with the actual load as well as the other models. The differences are small but still visible to the naked eye. Note that where a model type is omitted from the figure it is because it was not selected for any of the participant accounts.

FIGURE C-1: PG&E EX POST INDIVIDUAL MODEL PROXY DAY ACTUAL VS. PREDICTED LOAD - WEEKDAY

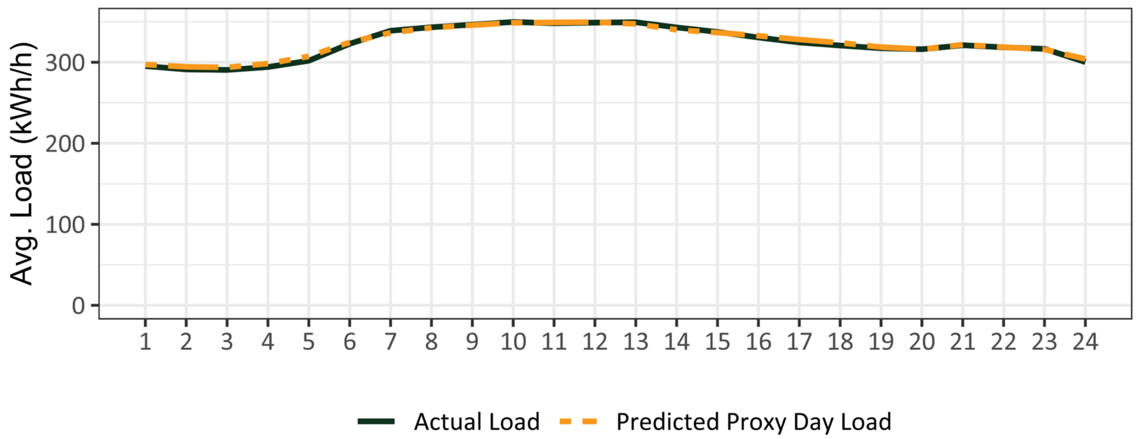


FIGURE C-2: PG&E EX POST INDIVIDUAL MODEL PROXY DAY ACTUAL VS. PREDICTED LOAD BY MODEL GROUP - WEEKDAY

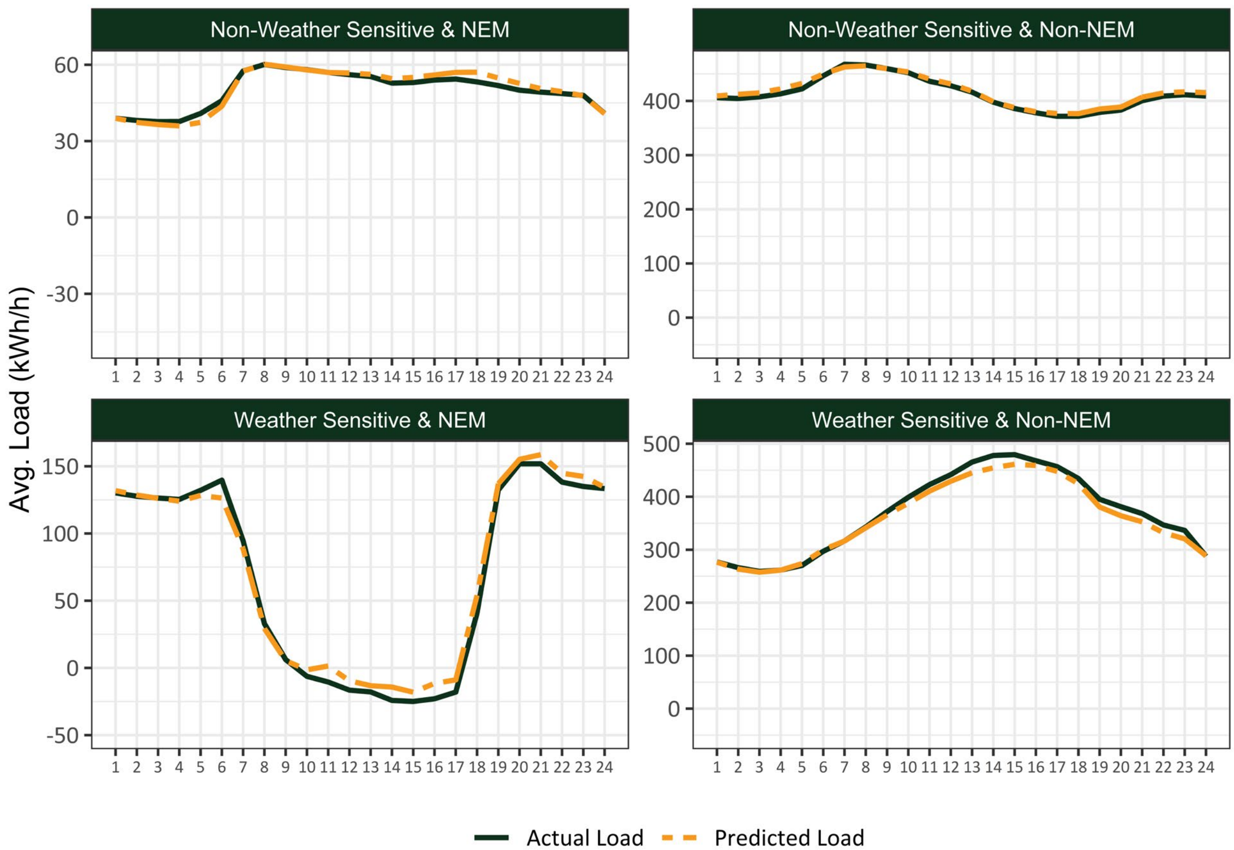


FIGURE C-3: SCE EX POST INDIVIDUAL MODEL PROXY DAY ACTUAL VS. PREDICTED LOAD - WEEKDAY

[redacted]

FIGURE C-4: SCE EX POST INDIVIDUAL MODEL PROXY DAY ACTUAL VS. PREDICTED LOAD BY MODEL GROUP - WEEKDAY

[redacted]

FIGURE C-5: PG&E EX POST INDIVIDUAL MODEL PROXY DAY ACTUAL VS. PREDICTED LOAD - WEEKEND

[redacted]

FIGURE C-6: PG&E EX POST INDIVIDUAL MODEL PROXY DAY ACTUAL VS. PREDICTED LOAD BY MODEL GROUP - WEEKEND

[redacted]

FIGURE C-7: SCE EX POST INDIVIDUAL MODEL PROXY DAY ACTUAL VS. PREDICTED LOAD - WEEKEND

[redacted]

FIGURE C-8: SCE EX POST INDIVIDUAL MODEL PROXY DAY ACTUAL VS. PREDICTED LOAD BY MODEL GROUP - WEEKEND

[redacted]

C.2.2 Ex Ante Models

The ex ante analysis required modification of the ex post model specifications to incorporate weekend event impacts into a single impact variable. This also required that weekday and weekend interval load data to be included into a single model, rather than modeled separately as in the ex post analysis. As a result, the Verdant team validated the adjusted model performance on proxy days to ensure that the adjustments did not diminish the accuracy and predictive power for estimating participant loads.

Figure C-9 and Figure C-10 shows the average actual and predicted load on weekday and weekend proxy event days for PG&E and SCE using the modified specifications included in the ex ante analysis. It should be noted that the ex ante analysis only included A.1 participants and excluded the SCE non-performers, as a result, the actual proxy day load shapes vary compared the actual load shapes presented in the ex post comparisons above.

FIGURE C-9: PG&E EX ANTE MODEL PROXY DAY ACTUAL VS. PREDICTED LOAD BY DAY TYPE

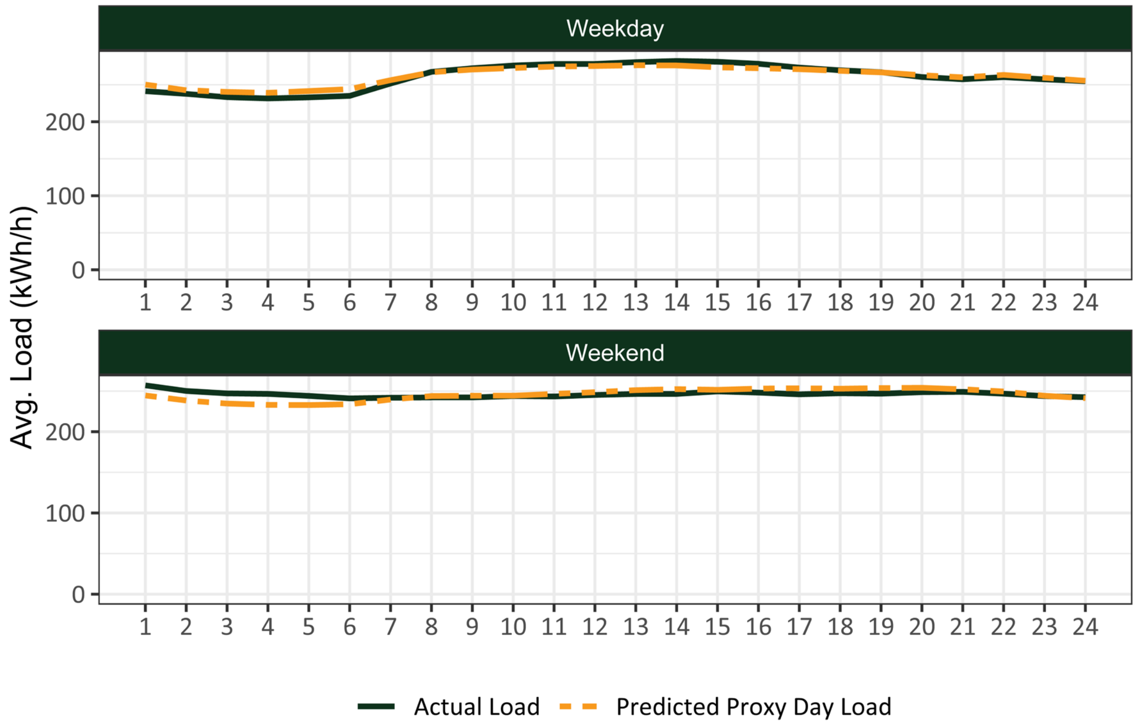
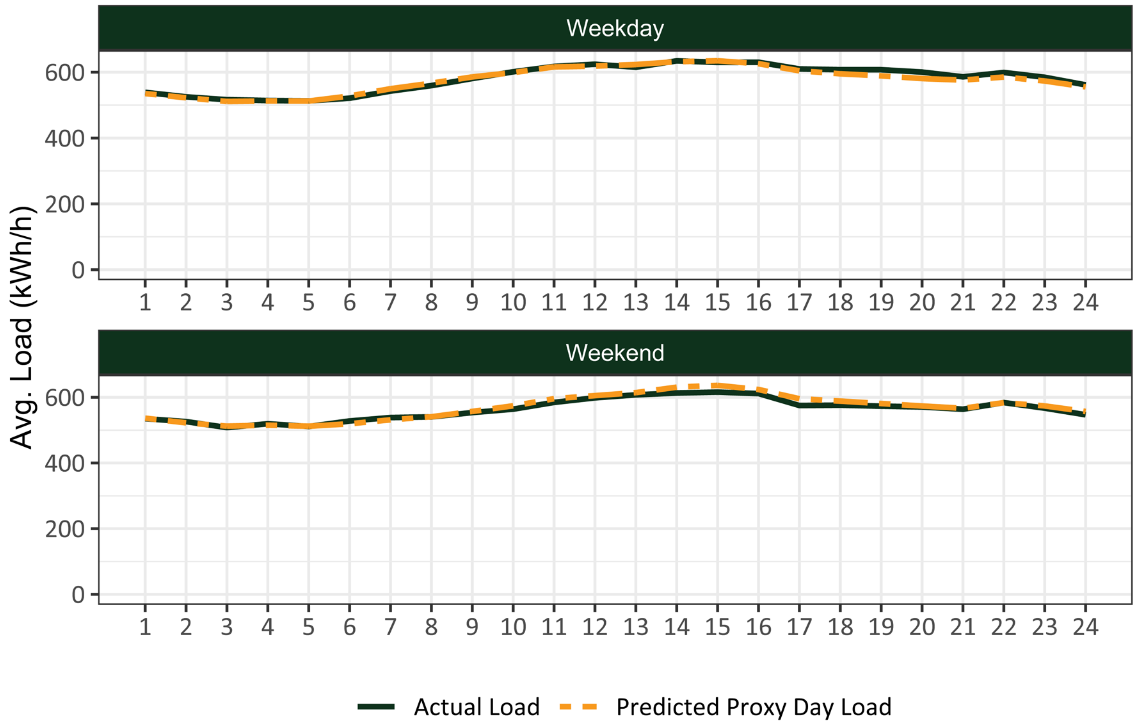


FIGURE C-10: SCE EX ANTE MODEL PROXY DAY ACTUAL VS. PREDICTED LOAD BY DAY TYPE



C.3 PROXY EVENT DAY IMPACT ESTIMATION

During the model selection process, candidate models were estimated using the proxy event days with presumed event hours to assess whether a model generates statistically significant parameters. The model selection arbitration rejected models that had, on average, statistically significant impacts on proxy event days. Given that no events were dispatched on these days the estimated impacts should not be statistically different from zero. Despite this, there were a small number of participants where customer specific models produced statistically significant results across all candidate models. The Verdant team attempted to remedy this; however, the significance of impacts could not be eliminated due to general volatility in the participant loads. The share of participants with selected models that have statistically significant proxy day impacts by IOU, analysis and day type is presented in Table C-7 below. It should be noted that the panel models did not result in statistically significant impacts on proxy days, as a result, they are not included in this discussion. Hours ending 18, 19, 20 and 21 were used as event hours, as these were the hours where events were dispatched for in 2021.

TABLE C-7: COUNT AND SHARE OF SELECTED INDIVIDUAL MODELS WITH STATISTICALLY SIGNIFICANT IMPACTS ON PROXY EVENT DAYS

Utility	Analysis	Day Type	Number of Service Points with Significant Impacts	Share with Significant Impacts*
PG&E	Ex Post	Weekday	33	4.2%
		Weekend	19	3.3%
	Ex Ante	Weekday and Weekend	15	2.1%
SCE	Ex Post	Weekday	2	5.1%
		Weekend	0	0.0%
	Ex Ante	Weekday and Weekend	1	2.7%

*Only participants included in each analysis are presented in participant shares. As a result, the number of participants in the denominator varies across analysis and day types.

APPENDIX D DUALLY ENROLLED BIP PARTICIPANT FSL VS EVENT DAY LOAD REDUCTIONS

Verdant examined the BIP FSL commitments along with observed participant load on July 9th to validate the assumption that all load reductions during overlapping BIP event hours are attributed to BIP rather than the ELRP. As part of this effort, Verdant removed the $OtherEventHour$ dummy variables from the ex post model to produce estimated refence loads for BIP event participation. It should be noted that Verdant was not able to match all BIP participants with FSLs provided by PG&E due to differences in the service agreement numbers used by Olivine and presented each the ELRP participation information and the BIP FSL information. Table D-1 below presents the number of matched service agreements and FSL commitments

TABLE D-1: DUALLY ENROLLED PARTICIPANT BIP FSL COMMITMENTS

Utility	Num. of Dually Enrolled BIP Customers	Matched Service Agreements	Percent Matched	Average FSL (kW)
PG&E	94	74	77.6%	335.8
SCE	4	4	100%	180.0

Figure D-1 and Figure D-2 present the BIP event day impacts and FSL commitments for PG&E and SCE dually enrolled ELRP and BIP participants with known FSL commitments. As seen in the Figure D-1, ELRP BIP participants, on average, did not exceed their FSL commitments. As a result, there are no additional impacts that could be claimed by the ELRP during those event hours. While SCE BIP participants do exceed their FSL commitments by an average of ~50 kWh/h, this only represents a 1.7% increase in load reductions over the FSL. As a result, the evaluation team deemed it reasonable to include overlapping ELRP and BIP event hour load reductions into the ELRP estimated reference load (baseline).

FIGURE D-1: PG&E ELRP DUALLY ENROLLED BIP EVENT DAY IMPACTS

[redacted]

FIGURE D-2: SCE ELRP DUALLY ENROLLED BIP EVENT DAY IMPACTS

[redacted]