Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

FINAL REPORT

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2023 Load Impact Evaluation for San Diego Gas and Electric's Emergency Load Reduction Pilot

Prepared for SD&GE
By Demand Side Analytics, LLC
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ABSTRACT

This study quantifies the demand impacts of the Residential and Non-Residential Emergency Load Reduction Program pilot. The study focuses on two primary research questions: What were the 2023 demand reductions due to dispatch operations? What is the magnitude of dispatchable load reduction capability for 1-in-2 and 1-in-10 weather planning conditions?

The pilot was rolled out in 2021 upon direction by the Commission to expand the state's portfolio of emergency load reduction resources beyond those available in CAISO capacity markets and utility specific emergency resources such as Critical Peak Pricing. Events are triggered by the CAISO in response to extreme grid stress, and event reductions are settled via a $2/kWh payment, determined using baseline settlement rules. Nine non-residential ELRP events were called in PY 2023, with different subgroups being dispatched for specific events. Neither the average PY2023 weekday 6pm to 9pm event or 8pm to 9pm event produced meaningful load reductions when evaluated across all non-residential ELRP subgroups. Two A.4 residential ELRP events were called in PY2023 and no A.6 residential ELRP events.

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1 EXECUTIVE SUMMARY

The Emergency Load Reduction Program (ELRP) pilot is a demand response program with direct settlements and performance payments to participant sites designed to access additional incremental load reduction during times of high grid stress and emergencies involving inadequate market resources, with the goal of avoiding rotating outages. The pilot was rolled out in 2021 upon direction by the Commission to expand the state's portfolio of emergency reliability resources beyond those available in CAISO capacity markets and utility specific load modifying resources such as Critical Peak Pricing. Two distinct groups of customers are eligible for ELRP participation: (Group A) directly enrolled residential and non-residential customers and aggregators, and (Group B) third-party demand response providers (DRPs) with market-integrated proxy DR (PDR) resources.

Group A: Direct enrolled residential and non-residential customers and aggregators:

- A.1. Non-Residential Customers (BIP, Non-Res CPP, SCE's RTP, AP-I, SDP-C allowed).
- A.2. Non-Residential Aggregation (BIP + Non-BIP Aggregators).
- A.3. Rule 21 Exporting Distributed Energy Resources (DER).
- A.4. Virtual Power Plant (VPP) Aggregators (AC Cycling allowed when using submetering to determine ILR; includes SCE SDP and SEP, PG&E's Smart AC Switches or BYOT, and SDG&E's AC Saver).
- A.5. Vehicle-Grid-Integration (VGI) Aggregators (AC Cycling Allowed when using submetering to determine ILR; includes SCE SDP, PG&E's Smart AC Switches or BYOT, and SDG&E's AC Saver)
- A.6. Residential Customers (Res CPP allowed).

Group B: Market-integrated PDR resources:

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

ELRP A.6 was rolled out in May of 2022 upon direction by the Commission to capture additional residential emergency load reduction resources. ELRP A.6 is a behavioral demand response program with direct settlements and performance payments to participants, which is currently planned to operate through 2025. All other ELRP subgroups are expected to discontinue after 2027. All ELRP groups remunerate participant site performance via a $2/kWh payment, determined using baseline settlement rules specific to each subgroup. However, settlement payments for A.6 will decrease in 2024 and 2025 to $1/kWh. The eligibility, targeting, and rollout of each subgroup are entirely different.

This study analyzes two primary research questions:

- What were the 2023 demand reductions due to dispatch operations?
- What is the magnitude of dispatchable load reduction capability for 1-in-2 and 1-in-10 weather planning conditions?

Table 1-1 summarizes the estimated ex post demand reductions for the average weekday ELRP event for each subgroup in which SDG&E customers are enrolled, to which enrollment is open and the sector to which enrollment is open (non-residential and residential). All impacts are incremental to other DR program impacts and statistical significance is noted for each subgroup. Subgroups A.4, [redacted] and B.2 produced statistically significant incremental impacts. Subgroups A.1, [redacted] did not. Subgroup A.6 was not dispatched in PY 2023. There were no enrollments in group B.1 in PY2023.

Table 1-1: Summary of 2023 Average Weekday Ex Post Demand Reductions[1]

ELRP Group	Sector	Sites	Load without DR (MW)	Load reduction (MW)	% Reduction	Significant (90% CI)	Significant (95% CI)
A.1: Non-Res Customers	Non-Residential	455	182.86	-9.39	-5.1%	No	No
A.2: Non-Res Aggregators	Non-Residential	[redacted]					
A.3: Rule 21 Exporting DERs	Non-Residential	[redacted]					
A.4: Virtual Power Plants (VPPs)	Residential & Non-Residential	334	0.15	1.13	748.1%	Yes	Yes
A.5: Vehicle-Grid-Integration (VGI)	Non-Residential	[redacted]					
A.6: Residential Customers	Residential	567,613	N/A	N/A	N/A	N/A	N/A
B.2: IOU Capacity Bidding	Non-Residential	145	17.57	1.63	9.3%	Yes	Yes

Table 1-2 summarizes forecasted site enrollments by subgroup, including the A.6 subgroup which is only approved through 2025. Non-residential enrollments are expected to remain flat and end after 2027. Total enrollments are concentrated in subgroups A.1 (non-residential customers not in DR programs) and A.4 (Virtual Power Plants, e.g. battery storage aggregation), which saw its first

[1] The average weekday event results incorporate impacts across multiple event windows (e.g. 6 pm to 9 pm and 8pm to 9 pm) as not all groups and events were dispatched for the same event windows.

enrollments in PY2023. Enrollments which surpass ex post participation counts reflect enrollments which occurred after the last event of the PY 2023 for each subgroup.

Table 1-2: Summary of Ex ante Site Enrollments

Year	A.1	A.2	A.3	A.4	A.5	A.6	B.2	Total
2023	649	[redacted]	[redacted]	335	[redacted]	567,613	166	568,768
2024	649	[redacted]	[redacted]	503	[redacted]	576,812	166	578,135
2025	649	[redacted]	[redacted]	754	[redacted]	590,513	166	592,087
2026	649	[redacted]	[redacted]	1,131	[redacted]	0	166	1,951
2027	649	[redacted]	[redacted]	1,696	[redacted]	0	166	2,516

Table 1-3 summarizes portfolio adjusted ELRP dispatchable ex ante reductions under August monthly peaking conditions for an SDG&E 1-in-2 weather year. Table 1-4 shows the same for program specific impacts. ELRP load reductions are assumed to be a function of curtailment of weather sensitive load on a percent basis except for exporting subgroups (A.3, A.4, A.5) for which reductions are the same for all weather specifications in PY 2023. The results in the table below reflect the reduction capability from 4pm to 9pm, which aligns with resource adequacy requirements. [redacted]

Table 1-3: Summary of Portfolio Adjusted Ex ante Dispatchable Demand Reductions, August Monthly Peak Day, SDG&E 1-in-2 Weather

Year	A.1	A.2	A.3	A.4	A.5	A.6	B.2	Total
2023	26.65	[redacted]	[redacted]	0.77	[redacted]	12.70	1.61	41.69
2024	26.65	[redacted]	[redacted]	1.15	[redacted]	13.36	1.61	42.74
2025	26.65	[redacted]	[redacted]	1.73	[redacted]	14.35	1.61	44.30
2026	26.65	[redacted]	[redacted]	2.59	[redacted]	0.00	1.61	30.81
2027	26.65	[redacted]	[redacted]	3.88	[redacted]	0.00	1.61	32.11

Table 1-4: Summary of Program Specific Ex ante Dispatchable Demand Reductions, August Monthly Peak Day, SDG&E 1-in-2 Weather

Year	A.1	A.2	A.3	A.4	A.5	A.6	B.2	Total
2023	26.65	[redacted]	[redacted]	0.77	[redacted]	16.50	1.61	45.49
2024	26.65	[redacted]	[redacted]	1.15	[redacted]	17.24	1.61	46.62
2025	26.65	[redacted]	[redacted]	1.73	[redacted]	18.35	1.61	48.30
2026	26.65	[redacted]	[redacted]	2.59	[redacted]	0.00	1.61	30.81
2027	26.65	[redacted]	[redacted]	3.88	[redacted]	0.00	1.61	32.11

2 INTRODUCTION

The Emergency Load Reduction Program (ELRP) pilot is a demand response program with direct settlements and performance payments to participant sites designed to access additional incremental load reduction during times of high grid stress and emergencies involving inadequate market resources, with the goal of avoiding rotating outages. The pilot was rolled out in 2021 upon direction by the Commission to expand the state's portfolio of emergency reliability resources beyond those available in CAISO capacity markets and utility specific load modifying resources such as Critical Peak Pricing. Two distinct groups of customers are eligible for ELRP participation: (Group A) directly enrolled residential and non-residential customers and aggregators, and (Group B) third-party demand response providers (DRPs) with market-integrated proxy DR (PDR) resources.

Group A: Direct enrolled residential and non-residential customers and aggregators:

- A.1. Non-Residential Customers (BIP, Non-Res CPP, SCE's RTP, AP-I, SDP-C allowed).
- A.2. Non-Residential Aggregation (BIP + Non-BIP Aggregators).
- A.3. Rule 21 Exporting Distributed Energy Resources (DER).
- A.4. Virtual Power Plant (VPP) Aggregators (AC Cycling allowed when using submetering to determine ILR; includes SCE SDP and SEP, PG&E's Smart AC Switches or BYOT, and SDG&E's AC Saver).
- A.5. Vehicle-Grid-Integration (VGI) Aggregators (AC Cycling Allowed when using submetering to determine ILR; includes SCE SDP and SEP, PG&E's Smart AC Switches or BYOT, and SDG&E's AC Saver).
- A.6. Residential Customers (Res CPP allowed).

Group B: Market-integrated PDR resources:

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

ELRP A.6 was rolled out in May of 2022 upon direction by the Commission to capture additional residential emergency load reduction resources. ELRP A.6 is a behavioral demand response program with direct settlements and performance payments to participants. On December 14, 2023, Decision (D.) 23-12-005 ordered that ELRP Group A (excluding sub-group A.6 PSR) and Group B pilot will continue through 2027, and ELRP sub-group A.6 pilot will continue through 2025. All ELRP groups remunerate participant site performance via a $2/kWh payment, determined using baseline settlement rules specific to each subgroup. However, settlement payments for A.6 will decrease in 2024 and 2025 to $1/kWh. The eligibility, targeting, and rollout of each subgroup are entirely different.

2.1 PROGRAM BACKGROUND

ELRP differs from market programs like Base Interruptible Load (BIP) and Capacity Bidding Program (CBP) in its eligibility, trigger, and settlement rules. Namely:

- **Deployment Triggers**: ELRP is dispatched via emergency triggers, as opposed to economic triggers.
- **Payment Rules**: ELRP has no penalties or capacity payments.
- **Baseline Settlement Rules**: ELRP utilizes top 10 of 10 or top 5 of 10 baselines with optional asymmetric adjustments and treatment of net exports (option to include for some groups, only exports considered for other groups).
- **Back Up Generation (BUG) Rules**: ELRP allows for BUG operation during events. BUG is generally ineligible for market programs.

The ELRP program dispatch rules are the following for all A and B subgroups:

- **Program availability**: May 1st – October 31st; seven days a week; 4 pm – 9 pm
- **Event duration**: 1-hour minimum; 5-hour maximum
- **Annual dispatch limit**: Up to 60 hours
- **Consecutive day dispatches**: No constraints

Group A participant sites must, in general, not be enrolled in a supply-side DR program offered by an IOU, third-party DRP, or CCA. Customers or providers which are enrolled in DR programs may be eligible for enrollment in Group B. Table 2-1 summarizes the eligibility rules for each subgroup.

Table 2-1: ELRP Group Eligibility Requirements

	Eligibility Requirements
A.1	Bundled and unbundled non-residential customers that meet all of the following criteria may directly participate in ELRP: ▪ Customer's service account is classified as non-residential; and ▪ Customer's service account must be able to reduce load by a minimum of one kilowatt during an ELRP event; and

Eligibility Requirements	
	▪ Customer is not simultaneously enrolled in another supply-side DR program offered by an IOU[2], third-party demand response provider (DRP), or community choice aggregator (CCA), with the exception that dual enrollment is in SDG&E's Base Interruptible Program (BIP). If an eligible BIP customer is participating with a BIP aggregator, then the BIP customer must participate under Sub-Group A.2.
A.2	Third-party, non-residential aggregators—including those participating in SDG&E's Base Interruptible Program (BIP)—are eligible to participate in ELRP. Aggregators can only add bundled and unbundled non-residential service accounts for ELRP that meet the following criteria: ▪ Customer's service account is classified as non-residential; and ▪ Customer's service account is not simultaneously enrolled in another DR program offered by an IOU (with the exception of BIP), demand response provider (DRP), or Community Choice Aggregator (CCA). ▪ BIP aggregators must enroll their entire BIP portfolio. If a BIP Aggregator chooses not to participate, its non-residential customers cannot independently participate in ELRP under Sub-Group A.1., unless their service account specific BIP firm service level can be determined. For non-BIP aggregators, the aggregated resource capacity meets or exceeds 500 kW.
A.3	Bundled and unbundled non-residential customers that meet all of the following criteria may directly participate in ELRP: ▪ Customer's service account is not simultaneously enrolled in any market integrated DR program offered by SDG&E, a third-party DRP, or CCA; and ▪ Customer's service account possesses a behind-the-meter (BTM) Rule 21- interconnected device (including Prohibited Resources/BUG) with an existing Rule 21 export permit; and ▪ Customer's BTM Rule 21 physical interconnected device has a minimum capacity of 25 kW and is able to export a minimum of 25 kW for at least one hour in compliance with Rule 21 and other applicable regulations and permits during an ELRP event
A.4	An aggregator managing a BTM virtual power plant (VPP) aggregation consisting of storage paired with net energy metering (NEM) solar or stand-alone storage deployed with residential (bundled or unbundled) or non-residential (bundled or unbundled) customers, whose VPP meet the following criteria, is eligible participate in ELRP:

[2] Dual enrollment in Critical Peak Pricing is allowed

	Eligibility Requirements
	▪ The VPP or any customer site within the aggregation is not simultaneously enrolled in a market-integrated DR program offered by an IOU, third-party DRP, or CCA, unless the ELRP A.4. payments to the aggregator are based on end use data and the customer site is enrolled in AC Saver. ▪ All sites within the VPP aggregation are located within the distribution service area of a single IOU, and ▪ The aggregated BTM storage capacity of the VPP meets the Minimum VPP Size Threshold of 500 kW, where the VPP size is determined by summing the Rule 21 interconnected capacity of the individual storage devices comprising the aggregation, and ▪ Each site within the VPP aggregation has a Rule 21 permit. ▪ A customer participating in ELRP A.6 is permitted, at any time, to enroll in ELRP A.4. After SDG&E becomes aware that the Participant's service account has been enrolled in ELRP A.4 SDG&E will de-enroll the service account from ELRP A.6
A.5	An aggregator managing a Vehicle-Grid-Integration (VGI) aggregation consisting of any combination of electric vehicles and charging stations – including those that are capable of managed one-way charging (V1G) and bi-directional charging and discharging (V2G) deployed with residential (bundled or unbundled) or non-residential (bundled or unbundled) customers that meets the following criteria, is eligible to participate in ELRP: ▪ The VGI aggregation or any customer site within the aggregation is not simultaneously enrolled in a market-integrated, supply-side DR program offered by an IOU, third-party DRP, or CCA, unless the ELRP A5 payments to the aggregator are based on end use data and the customer site is enrolled in AC Saver ▪ All sites within the VGI aggregation are located within the distribution service area of a single IOU, and ▪ The VGI aggregation can contribute Incremental Load Reduction (ILR) of at least 25 kW for a minimum of one hour during an ELRP event. ▪ Subject to Rule 21 interconnection requirements, any direct current (DC) V2G electric vehicle supply equipment (EVSE) that has UL 1741 certification but not UL 1741 SA certification, any subsequent UL 1741 supplement certification required in Rule 21, or Smart Inverter Working Group-recommended smart inverter functions may interconnect initially, but only for the purpose of participating in the ELRP. ▪ A customer participating in ELRP A.6 is permitted, at any time, to enroll in ELRP A.5. After SDG&E becomes aware that the Participant's service account has been enrolled in ELRP A.5 SDG&E will de-enroll the service account from ELRP A.6.

	Eligibility Requirements
A.6	SDG&E shall determine it its sole discretion Participant's eligibility which must include: ▪ Participant receives electric service on a residential rate ▪ Participant has an active service agreement with SDG&E ▪ Participant has a SDG&E SmartMeter ▪ Participant is not simultaneously enrolled in another supply-side demand response program offered by SDG&E, third party DR provider (DRP), Community Choice Aggregator (CCA), or in ELRP sub-groups A.4 or A.5 ▪ Participant is not an electric customer of a Community Choice Aggregator who has opted out of being included in the Pilot
B.1	A third Party DRP with a market-integrated Proxy Demand Resource (PDR) is eligible to participate in the ELRP. This subgroup is not included in this evaluation.
B.2	Third-party aggregators (Aggregators) or self-aggregated customers (Participant sites) enrolled and participating in SDG&E's Capacity Bidding Program are eligible to participate in the ELRP.

2.2 STUDY RESEARCH QUESTIONS

Table 2-2 summarizes the key research questions for the ELRP program.

Table 2-2: Key Research Questions

	Research Question
1	What were the demand reductions due to program operations and interventions in 2023 – for each event day and hour?
2	How does weather influence the magnitude of demand response?
3	How do load impacts differ for customers in each subgroup (Group A and Group B subgroups) during PY2023?
4	What are the ex ante load reduction capabilities for 1-in-2 and 1-in-10 weather conditions? And how well do those align with ex post results?
5	What concrete steps or experimental tests can be undertaken to improve program performance?

2.3 OVERVIEW OF METHODS

The primary challenge of impact evaluation is the need to accurately detect changes in energy consumption while systematically eliminating plausible alternative explanations for those changes, including random chance. Did the introduction of the ELRP program cause a change in critical peak period demand? Or can the differences be explained by other factors? To estimate energy savings, it is necessary to estimate what energy consumption would have been in the absence of the intervention—the counterfactual or reference load.

The change in energy use patterns was estimated using a combination of difference-in-differences with matched controls and individual customer regressions. Figure 2-1 summarizes the selection framework used to determine the appropriate method for each site, using subgroup A.1 as an example. Most sites utilize a difference-in-difference model, except for in cases where there were not enough sites in a given segment (customer size and climate zone) or for sites with an annual peak above 200 kW and daily usage patterns which exhibited substantial statistical noise (CVRMSE[3] above 0.25).

Figure 2-1: Ex Post Methodology Selection Framework

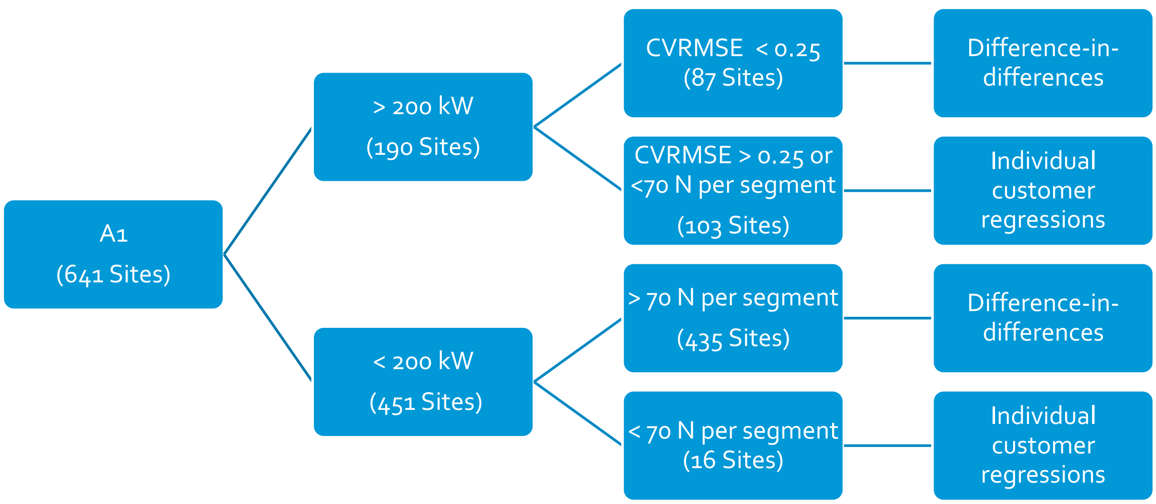


Table 2-3 summarizes the approach or approaches used for each subgroup. Note that for some subgroups a combination of methods was used. Additionally, no ex-post evaluation methodologies were applicable to subgroup A.6 since this subgroup was not dispatched in PY2023. However, if events had been called, difference-in-differences would have been used.

[3] Coefficient of the Variation of the Root Mean Square Error: RMSE is the average distance between modeled and observed usage. CVRMSE reflects the relative size of the errors modeled for each site, normalized for the magnitude of each site's energy usage.

Table 2-3: Evaluation Methodology Used by Subgroup

ELRP Group	Individual customer regressions	Difference-in-differences
A.1	✓	✓
A.2	✓	
A.3	✓	
A.5	✓	
B.2	✓	✓
A.4		✓
A.6	N/A	N/A

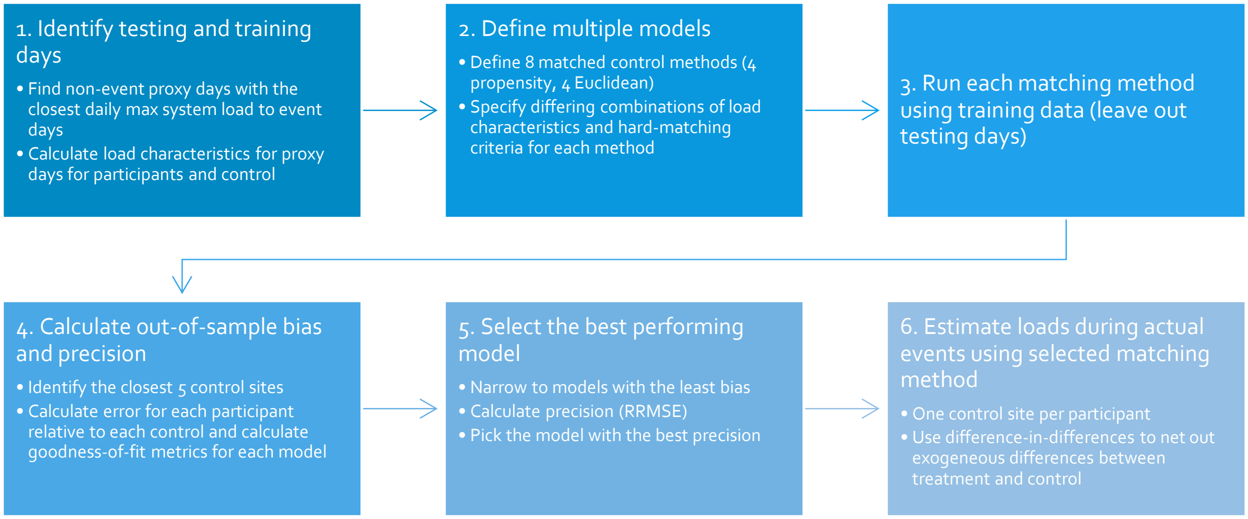
Site-specific models for individual customer regressions were selected among dozens of potential specifications, which included synthetic controls[4] using one or more matched control site to help control for factors outside of the ELRP events. Similarly, the difference-in-differences approach used a matched control group to net out changes in energy usage patterns not due to the ELRP events. As such, regardless of evaluation methodology, each participant site was matched to one or more non-participant using an out of sample matching tournament where match quality was compared across eight different matching models to identify the best performing model.

Figure 2-2 summarizes the matching tournament process used to select matched controls for the difference-in-difference analyses and synthetic controls for the individual customer regressions. To identify the control pool sites that best matched each participant site's energy use patterns on event-like, proxy days (similar in weather and system conditions to event days), eight matching methods were tested. These methods included different matching algorithms (e.g. Euclidean and propensity matching) and different site characteristics. Matching methods included different combinations of proxy day load characteristics such as load factor, load shape, and weather sensitivity. Control candidates were also "hard-matched" on climate zone, net metering status, and size bin[5].

[4] The functional form of a regression with synthetic controls differs from a panel difference in difference regression in that usage for the control or controls are specified as right hand predictor variables. Additional detailed are available in the Appendix

[5] Bins were constructed using average usage on event-like, proxy days. For solar customers, bins were constructed based on system size.

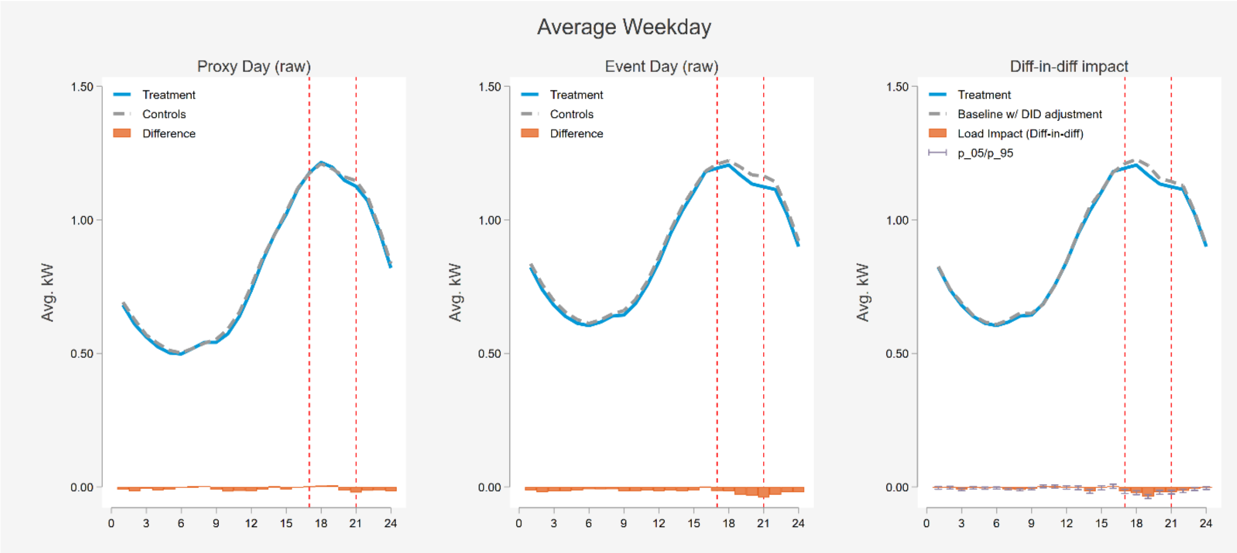
Figure 2-2: Out of Sample Process for Control Group Selection



As described above, difference-in-differences with matched controls was the primary evaluation methodology used, except in cases where there were few sites or large sites with noisy load patterns[6]. Figure 2-3 below demonstrates the mechanics of a difference-in-difference calculation. In the first panel, average observed loads on proxy days are shown for participants and for their matched controls. The difference between these two is the first "difference" and quantifies underlying differences between participants and their controls not attributable to event participation. Note that this first difference is very small, indicative of a high-quality match and sufficient sample size to neutralize the noise inherent in individual customer loads. The second panel shows the average observed participant and matched control loads on event days. The gap between these two is the second "difference" which includes both the difference due to event participation and the underlying first difference observable on non-event days. The third panel shows the average event day loads after netting out the proxy day difference from the event day control load. The result is the difference-in-differences impact.

[6] Out of sample testing was used to calculate RRMSE and other bias and fit metrics to compare across multiple pooled methods (average customer regressions and panel regressions). Based on this testing, difference-in-differences was determined to outperform or at least be comparable in robustness to the other methods. In contrast to the pooled regression-based methods, difference-in-difference has the advantage of enabling segmentation of results (by size, climate zone, industry, solar status, etc.) without the need to run additional regressions while ensuring that segment results add up to group totals.

Figure 2-3: Difference-in-Differences Calculation Example



In cases where a difference-in-differences approach was not deemed appropriate due to insufficient sample size or for large sites with noisy loads, site-specific individual customer regression models were selected using another out of sample tournament to select the most accurate regression model specification for each participant site. Synthetic controls were considered in this tournament, including inclusion of an industry profile based on NAICS code and inclusion of solar irradiance. A variety of within subjects lagged loads (1 day, 1 week, 2 weeks) were also considered. To implement out of sample testing, the top 50 system load days, excluding event days, were randomly divided into testing and training datasets. Bias and fit metrics were calculated using the testing dataset and the model with the best fit (lowest Root Mean Squared Error) was selected among models with the least bias (Mean Absolute Error[7]). Site specific load impacts were estimated using the best model for each site.

Site specific regression models were selected from 120 different possible specifications across the following parameters:

- Inclusion of an industry profile constructed of loads for other similar large commercial and industrial customers[8]
- Inclusion of local solar irradiance data[9]
- Number of control sites[10]

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[7] MAE was used rather that Mean Average Percent Error (MAPE) to ensure robustness for sites with loads very close to zero, common for sites solar or other generation.

[8] Selected from granular load profiles within climate zone and industry segment constructed and maintained by Demand Side Analytics for SDG&E for the population NMEC settlement validation purposes for the Summer Reliability Market Access Program.

[9] Specific to the weather station nearest to the participant.

[10] Ranges from 0 to 5, selected using the out of sample match selection process.

- Lags of load data[11]

Figure 2-4 shows the different model parameters that were included in the site-specific model tournament and the number of sites[12] for which each parameter was included in the winning model. The wide spread across parameters indicates that it was important to allow for individually tailored models to be selected for each participating site.

Figure 2-4: Modeling Parameters Tested and Inclusion in Best Performing Site Specific Models

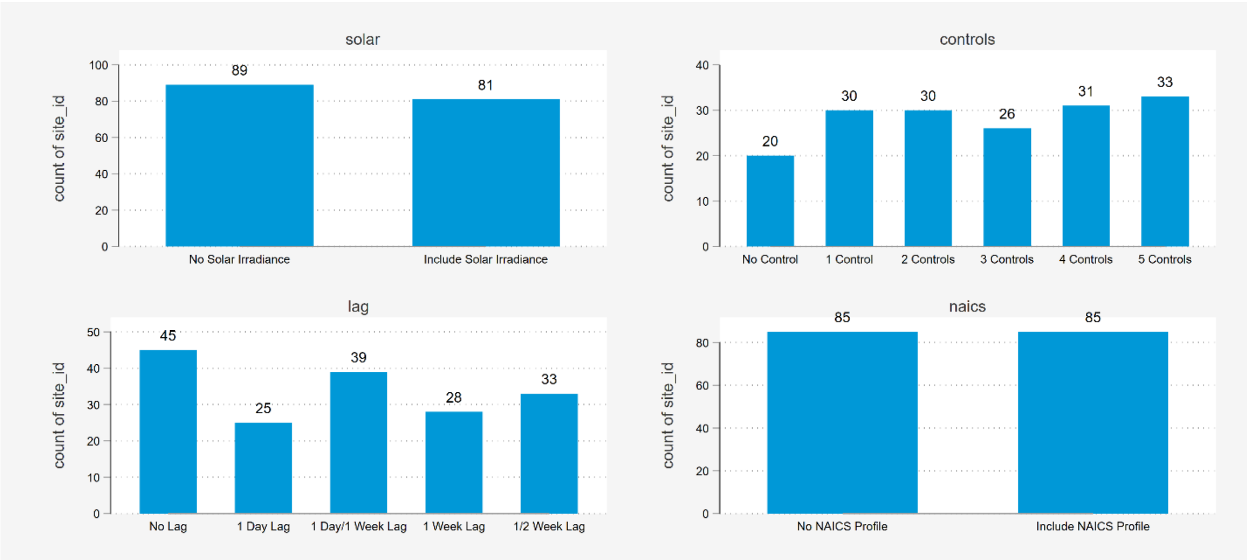

Table 2-4 summarizes the data sources, segmentation, and estimation methods used for each program. The segmentation was defined in advance of the analysis and is of particular importance because the evaluation used a bottom-up approach to estimate impacts to ensure that aggregate impacts across segments equaled the sum of the parts. Because impacts for each segment were added together, the segmentation was structured to be mutually exclusive and completely exhaustive. In other words, every customer was assigned to exactly one segment. Within each ELRP subgroup, the segmentation differentiated customers who were expected to deliver greater demand reductions– such as customers in the inland climate zone where cooling loads are higher– from customers who were expected to deliver lower demand reductions. For non-residential subgroups customer size was also used[13].

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[11] Lags were designed to capture the tendency of large commercial and industrial customers to operate on daily, weekly, or bi-weekly schedules irrespective of weather or time of year.
[12] Shown for the 168 sites across groups for which individual customer regressions were selected.
[13] In PY2022, eligibility group was applied to the A6 subgroup given the substantial difference in impact expected for default versus opt-in enrollment. This would again have been the case in PY2023, but this subgroup was not dispatched.

Additional segments were analyzed, after the fact, as part of exploratory analysis, but the core results presented are based on the segmentation detailed below.

Table 2-4: Evaluation Methods

Evaluation Element	Non-Residential ELRP (A.1, A.2, A.3, A.4, A.5, B.2)
Data sources / samples	▪ All event season data for the past program year for ✓ All 607 Non-Residential ELRP participant sites, all 335 A4 participant sites, and a sample of 35,508 A6 participant sites ✓ a control pool of 41k commercial non-participants and 18k non-participant residential sites with battery storage
Segmentation	▪ ELRP Subgroup ▪ Climate zone (e.g. Coastal or Inland) ▪ Size (non-residential groups only, Small, Medium, Large based on rate size)
Estimation method (Ex-post)	▪ Primary method: difference-in-differences with matched controls ▪ Secondary method: Site specific regression models with synthetic controls o Applied in cases where there were few sites within a segment or large sites with noisy load patterns
Estimation method (Ex-ante)	▪ Top-down enrollment model based on projections for interconnected capacity and feasible enrollment levels. ▪ Load reductions are assumed to be a function of dispatchable generation capacity not weather sensitive load curtailment and therefore the same for all weather specifications

3 ELRP EVENT DAY IMPACTS

Emergency Load Reduction Program (ELRP) participant sites receive day ahead or day-of event notifications via email and phone. The A.4 subgroup participants receive dispatch signals sent to their battery storage devices installed on the premises.

3.1 EVENT CHARACTERISTICS

Event impacts were assessed by site (premise and service point combination). While the modeling was performed individually for each site, results are reported by ELRP subgroup, summarized in Table 3-1. This table also summarizes the number of sample sites used for the ex post event analysis once data cleaning was completed, as well as the total number of sites enrolled during the PY2023 event season (the first event was called on July 20 and the last on October 6). The number of sites in the ex post analysis is slightly smaller than the total number of sites, due to the removal of sites with outages on event days and sites for which an adequate matched control could not be found. The sampled sites for A.6 were designed to be representative of the large program population, although there was no ex post analysis for this group in PY2023.

Table 3-1: Participant Populations (Avg Weekday Event)

ELRP Group	Sector	Total sites	Sites in analysis
A.1	Non-Residential	466	466
A.2	Non-Residential	[redacted]	[redacted]
A.3	Non-Residential	[redacted]	[redacted]
A.4	Residential & Non-Residential	334	334
A.5	Non-Residential	[redacted]	[redacted]
A.6	Residential	567,613	35,508
B.2	Non-Residential	145	143
Total		**568,563**	**36,456**

Table 3-2 shows the eleven PY2023 ELRP event days and the SDG&E system peak load on each day. While event dispatch dates and hours were the same for most non-residential subgroups and events in July, the August, September, and October events were typically called for a few specific subgroups on specific hours. All eleven events occurred on weekdays, and none occurred on weekends or holidays. The SDG&E system peaked on August 28, coinciding with a 6 to 9 pm event called for A.2 and A.5. No events were called for subgroup A.6 in PY2023.

Table 3-2: ELRP Events in 2023

Event date	Day of week	Event window	A.1	A.2	A.3	A.4	A.5	A.6	B.2	Max SDG&E system load (MW)
7/20/2023	Thursday	8 to 9 pm	✓	✓	✓		✓		✓	3,380
7/25/2023	Tuesday	8 to 9 pm	✓	✓	✓		✓		✓	3,387
7/26/2023	Wednesday	6 to 9 pm	✓	✓	✓		✓		✓	3,634
8/28/2023	Monday	6 to 9 pm		✓			✓			4,375
8/29/2023	Tuesday	4 to 9 pm					✓			4,127
8/30/2023	Wednesday	6 to 9 pm					✓			3,801
9/19/2023	Tuesday	6 to 8 pm*		✓			✓			2,875
9/26/2023	Tuesday	4 to 9 pm					✓			2,987
9/27/2023	Wednesday	4 to 9 pm					✓			2,919
10/5/2023	Thursday	6 to 8 pm				✓				3,349
10/6/2023	Friday	7 to 9 pm				✓				3,261

*Group A.5 called from 5 to 9 pm

Shaded rows indicate dates on which Small CPP, CBP, or AC Saver Day Ahead were called.

3.2 DATA SOURCES AND ANALYSIS METHOD

Table 3-3 summarizes the five data sources used to conduct the Non-Residential and Residential ELRP event impact analysis. The analysis was performed by site on hourly load data. Various data sources were used to classify sites into the study segments. While different segments were developed for the various analyses in this report, the characteristic definitions used to build segments were consistent across analyses.

Table 3-3: Non-Residential and Residential ELRP Event Impact Evaluation Data Sources

Source	Comments
Hourly interval data	▪ Summer 2023 ▪ All analysis done by site (premise id-service point id pair)
Outage information	▪ PSPS and emergency outage data details which customers and what timeframes were impacted by outages
Customer characteristics	▪ Non-residential treatment: 607 customer sites ▪ Residential treatment: 332 A.4 sites, 35,508 A.6 sites ▪ Non-residential controls: 41k non-residential sites ▪ A4 controls: 18k residential sites with battery storage

Source	Comments
	▪ NEM status, climate zones used in matched control selection ▪ NAICS codes for development of industry profiles
SDG&E hourly system loads	▪ Summer 2023 ▪ Used to identify non-event high system load days
Ex post weather data by weather station	▪ Used to derive weather sensitivity for treatment and control pool sites, used as a matching criteria ▪ Solar irradiance considered for site specific regression model selection

The primary analysis method was difference-in-differences with matched controls. Site-specific individual regression models with synthetic controls were used in cases where there were too few participant sites in a segment or for very large sites (peak load above 200 kW) with noisy daily load patterns (CVRMSE above 0.25). An out of sample tournament was used to select a matching model for each subgroup. Matches were one of multiple controls used in the regression models. A winning distance matching model was selected for each subgroup. These winning models were used to select five matches for each of the ELRP participant sites among the appropriate control candidate pool, which is comprised of sites not enrolled in other DR programs because it may influence energy use and renders a customer ineligible for ELRP[15].

Once the matches were selected for each participant, the difference-in-differences model was used to assess impacts and standard errors for each event and each study segment, using the top match for each site. For sites requiring individual customer regressions, an out of sample tournament was used to select site specific regression models among dozens of possible specifications across 4 parameters: industry profiles, solar irradiance, up to five synthetic controls (selected in the tournament described above), and lagged participant site loads.

3.3 EX POST LOAD IMPACTS

3.3.1 ELRP GROUP A.1 IMPACTS BY EVENT

Group A.1 is designated for non-residential customers that are not participating in DR programs. It is currently the largest ELRP subgroup by far with over 400 participating sites. There were three events called for subgroup A.1 in PY2023, across a variety of durations and start times. Table 3-4 summarizes the load reductions and participant weighted event temperatures for ELRP A.1 sites on event days or

[15] For the B2 subgroup, which is explicitly designed for dual participation with CBP, controls were pulled from the same pool of non-DR participants.

the average event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

A.1 showed no statistically significant event impacts. One possible reason for this finding is that for the July 20th and 25th events no advance event notification was given and for the July 26th event only a few hours' notice was given ahead of dispatch, which did not give participants sufficient time to shed load. Table 3-4 also summarizes the number of sites enrolled and analyzed for each event day. A participant site needed to have data available both for the event day and the relevant proxy day, as well as have found a matched control, to be included in the estimate for a given event.

Table 3-4: ELRP A.1 Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
7/20/2023	8 to 9 pm	69.6	453	-11.27	-6.3%	-24.87	No	No
7/25/2023	8 to 9 pm	71.1	456	-7.87	-4.4%	-17.25	No	No
7/26/2023	6 to 9 pm	72.5	456	-8.37	-4.4%	-18.35	No	No
Avg Weekday 8-9 pm	**8 to 9 pm**	**70.3**	**455**	**-9.48**	**-5.3%**	**-20.86**	**No**	**No**
Avg Weekday 6-9 pm	**6 to 9 pm**	**72.5**	**456**	**-8.37**	**-4.4%**	**-18.35**	**No**	**No**
Avg Weekday (any)	**6 to 9 pm**	**71.5**	**455**	**-9.39**	**-5.1%**	**-20.63**	**No**	**No**

3.3.2 ELRP Group A.2 Impacts by Event

Group A.2 is designated for non-residential aggregators not participating in DR programs and included [redacted] in PY2023. There were five events called for subgroup A.2 in PY2023, across a variety of durations and start times. Table 3-5 summarizes the load reductions and participant weighted event temperatures for the ELRP A.2 site on event days or the average event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

[redacted]

Table 3-5: ELRP Group A.2 Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
7/20/2023	8 to 9 pm	[redacted]						
7/25/2023	8 to 9 pm	[redacted]						
7/26/2023	6 to 9 pm	[redacted]						
8/28/2023	6 to 9 pm	[redacted]						
9/19/2023	6 to 8 pm	[redacted]						
Avg Weekday 8-9 pm	8 to 9 pm	[redacted]						
Avg Weekday 6-9 pm	6 to 9 pm	[redacted]						
Avg Weekday (any)	6 to 9 pm	[redacted]						

3.3.3 ELRP Group A.3 Impacts by Event

Group A.3 is designated for non-residential rule 21 exporting DERs not participating in DR programs and was comprised of [redacted] in PY2023. There were three events called for subgroup A.3 in PY2023, across a variety of durations and start times. Table 3-6 summarizes the load reductions and participant weighted event temperatures for ELRP A.5 sites on event days or the average event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

[redacted]

Table 3-6: ELRP Group A.3 Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
7/20/2023	8 to 9 pm	[redacted]						
7/25/2023	8 to 9 pm	[redacted]						
7/26/2023	6 to 9 pm	[redacted]						
Avg Weekday 8-9 pm	8 to 9 pm	[redacted]						
Avg Weekday 6-9 pm	6 to 9 pm	[redacted]						
Avg Weekday (any)	6 to 9 pm	[redacted]						

3.3.4 ELRP Group A.4 Impacts by Event

Group A.4 is designated for aggregators managing a behind the meter virtual power plant (VPP) aggregation of residential or non-residential customers. In PY2023, there was one aggregator enrolled, consisting of 334 residential participant sites. There were two events called for subgroup A.4 in PY2023, both with a two hour duration with one starting at 6pm and one at 7pm. Table 3-7 summarizes the load reductions and participant weighted event temperatures for ELRP A.4 sites during the two events and for the average weekday event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Both the individual event days and the average weekday event reductions were significant and meaningful, unlike most other subgroups in PY2023. Aggregate reductions for significant events range from 1.13 MW (October 5th) to 1.16 MW (October 6th). No clear correlation between weather conditions, event window, and load reductions is evident. This makes sense conceptually since A.4 load reductions are typically only dependent on battery capacity. Additional observations from future events should help confirm this observation. Significance was not correlated with event temperature and all events produced statistically significant load reductions.

Table 3-7: ELRP Group A.4 Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post)			Significant (90% CI)	Significant (95% CI)
				Aggregate (MW)	% Reduction	Average Site (kW)		
10/5/2023	6 to 8 pm	70.8	331	1.11	918.8%	3.41	Yes	Yes
10/6/2023	7 to 9 pm	65.8	334	1.14	627.6%	3.47	Yes	Yes
Avg Weekday 6-8pm	**6 to 8 pm**	**70.8**	**331**	**1.11**	**918.8%**	**3.41**	**Yes**	**Yes**
Avg Weekday (any)	**6 to 9 pm**	**68.3**	**334**	**1.13**	**748.1%**	**3.44**	**Yes**	**Yes**

3.3.5 ELRP Group A.5 Impacts by Event

Group A.5 is designated for non-residential vehicle-grid integration (VGI) aggregators not participating in DR programs and was comprised of three participating sites in PY2023. There were nine events called for subgroup A.5 in PY2023, across a variety of durations and start times. Table 3-8 summarizes the load reductions and participant weighted event temperatures for ELRP A.5 sites during the nine events and for the average weekday event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

The average 6pm to 9pm weekday event reductions were significant at the 90% confidence level. No signification reductions were observed for the 8 to 9pm events which fell on July 20th and 25th. One possible reason for this finding is that for the July 20th and 25th events and hour or less of notice was provided, which did not give participants sufficient time to shed load. Significant reductions were observed for most subsequent events including for the July 26th event for which a few hours' notice was given ahead of dispatch. This is not surprising given that response for A.5 is essentially technology enabled which may facilitate event response.

[redacted]

[redacted]

Table 3-8: ELRP Group A.5 Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post) Aggregate (MW)	% Reduction	Average Site (kW)	Significant (90% CI)	Significant (95% CI)
7/20/2023	8 to 9 pm	[redacted]						
7/25/2023	8 to 9 pm							
7/26/2023	6 to 9 pm							
8/28/2023	6 to 9 pm							
8/29/2023	4 to 9 pm							
8/30/2023	6 to 9 pm							
9/19/2023	5 to 9 pm							
9/26/2023	4 to 9 pm							
9/27/2023	4 to 9 pm							
Avg Weekday 8-9 pm	**8 to 9 pm**							
Avg Weekday 6-9 pm	**6 to 9 pm**							
Avg Weekday (any)	**4 to 9 pm**							

3.3.6 ELRP Group A.6 Impacts by Event

There were no events called for Group A.6 during PY2023, so ex post impacts cannot be evaluated for this group.

3.3.7 ELRP Group B.2 Impacts by Event

Group B.2 is designated for IOU capacity bidding program (CBP) PDR resources and was comprised of 143 participating sites in PY2023. There were three events called for subgroup B.2 in PY2023, across a variety of durations and start times. Table 3-9 summarizes the load reductions and participant weighted event temperatures for ELRP B.2 sites during the three events and for the average weekday event. The average weekday event reductions were significant and meaningful, unlike most other subgroups in PY2023. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Aggregate reductions for significant events range from 1.83 MW (July 25th) to 2.29 MW (July 26th). No signification reductions were observed for the July 20th event for which notification was given after the start of the event. Significant reductions of 11% and 12.4%, respectively, were observed for the July 25th event for which an hour of notice was given and for the July 26th event for which a few hours of advance notice were given. Though percent reductions were similar for these two events, reductions were sustained for three hours for the July 26th event and first hour reductions were 18%. In contrast, the July 25th event yielded one hour of 11% reductions. The difference in advance notice between these events is a logical explanation for the difference in impacts. There were not enough events to establish a relationship between weather and impacts.

Table 3-9 also summarizes the number of sites enrolled and analyzed for each event day. A participant site needed to have data available both for the event day and the relevant proxy day, as well as have found a matched control, to be included in the estimate for a given event. The population changed meaningfully relative to PY 2022. All but one A.2 participant moved to B.2 and an additional 42 new participants enrolled in B2.

Table 3-9: ELRP Group B.2 Event Reductions

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post)			Significant (90% CI)	Significant (95% CI)
				Aggregate (MW)	% Reduction	Average Site (kW)		
7/20/2023	8 to 9 pm	70.4	145	0.27	1.6%	1.85	No	No
7/25/2023	8 to 9 pm	71.1	145	1.83	11.0%	12.59	Yes	Yes
7/26/2023	6 to 9 pm	73.1	145	2.29	12.4%	15.78	Yes	Yes
Avg Weekday 8-9 pm	**8 to 9 pm**	**70.7**	**145**	**1.05**	**6.3%**	**7.22**	**Yes**	**Yes**
Avg Weekday 6-9 pm	**6 to 9 pm**	**73.1**	**145**	**2.29**	**12.4%**	**15.78**	**Yes**	**Yes**
Avg Weekday (any)	**6 to 9 pm**	**71.8**	**145**	**1.63**	**9.3%**	**11.22**	**Yes**	**Yes**

3.3.8 Comparison of Evaluation Load Reductions to Baseline Approach

The ELRP pilot remunerates participant site performance via a $2/kWh payment, determined using baseline settlement rules specific to each subgroup. The baseline rules are mostly applied at the customer account level[16] and differ for weekday and weekend events as follows:

- Group A All Events[17]:
  - Calculate the average event hour load for the prior 10 non-event calendar days.
  - Take the average hour loads across these 10 days. This is the baseline for that customer for that event.
  - Calculate a same day adjustment and apply to the average non-event day load: the ratio of the average event day load (first three hours of the four preceding the event) to the same hours on the average non-event day loads[18].
  - Subtract observed load from the adjusted baseline to calculate the load reduction.
  - To determine the kWh eligible for payment, take the load reduction in each hour during the event window and sum. No payments or penalties apply to totals below zero kWh for an event hour.

[16] Settlement occurs at the aggregator level for A.4 and B.2

[17] These baseline calculation rules apply for Group A.1, and this section does not include the slight differences in baseline methodology for other subgroups.

[18] Capped at minimum 1.00 and maximum 1.40.

- Group B All Events: follows slightly different baseline calculation rules which include steps for netting out CBP event reductions to avoid double counting.

The baseline approach is used to determine settlements for participant sites because it is simple to calculate and simple to explain to customers. Table 3-10 compares the ELRP settlement baseline to the control group based methods used for the load impact evaluation and underscores why the latter is more methodologically robust.

Table 3-10: Comparison of Settlement Baseline and Load Impact Evaluation Methodologies

	Settlement Baseline	Load Impact Evaluation
Approach	Within-subjects baseline	Difference-in-difference with matched controls supplemented by Site specific regression with synthetic controls
Does the approach control for exogenous factors?	No. A pre-post within subjects approach only compares participant site load before and during the event. There is no way to identify changes in loads that may not be due to the event.	Yes. Any changes in load not due to the event will be apparent in the loads of the controls.
Does the approach minimize statistical noise?	No. The calculation occurs at the account level[19] and individual account loads are inherently noisy from day to day.	Yes. Tournaments are used to select controls and regression models which minimize error and bias. Then results are aggregated across participating sites (hundreds of customers for some subgroups). Noise that is apparent at the individual level is thereby averaged out.
Is the approach symmetrical?	No. The baseline may be adjusted upwards, but not downwards. Also, customers are compensated for positive event reductions (after summing positive and negative event reductions across event hours[20]) but there is no penalty for reductions which are negative.	Yes. Load increases are treated no differently than load reductions.

[19] Settlement occurs at the aggregator level for A.4 and B.2
[20] Negative reductions are set to 0 before summing across event hours for B.2

Table 3-11 compares ex post results to baseline results across all event hours. The baseline is within ten percent of the ex post results for B.2 and A.4, which are the two subgroups with produced significant meaningful impacts in PY2023. For the other subgroups, the baseline and ex post results are simply noise.

Table 3-11: ELRP Ex post Results vs Baseline Results

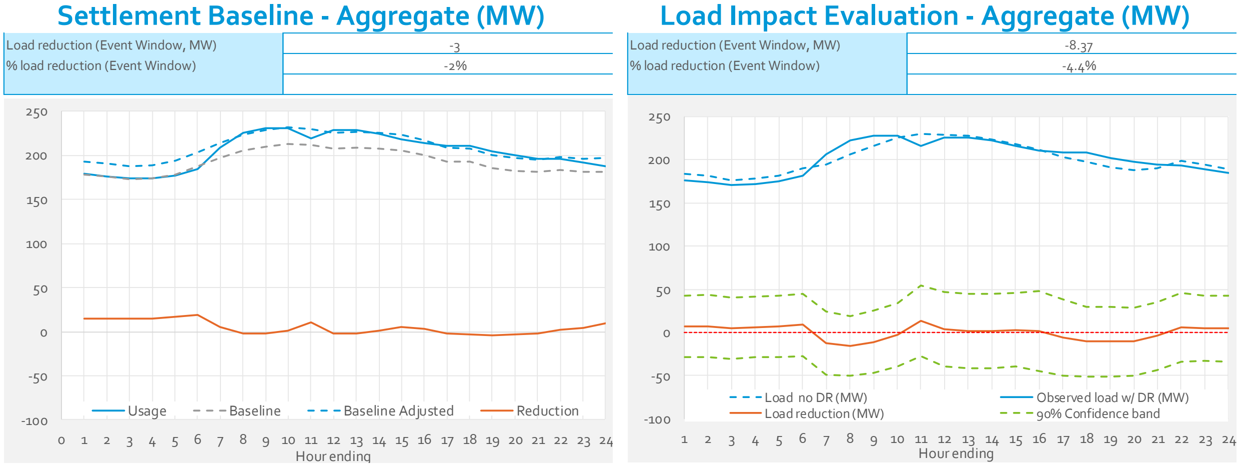
Subgroup	Max Event Window*	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post)			Significant (90% CI)	Significant (95% CI)	Reductions (Baseline)	
				Aggregate (MW)	% Reduction	Average Site (kW)			Aggregate (MW)	Average Site (kW)
A1	6 to 9 pm	71.5	455	-9.39	-5.1%	-20.63	No	No	-0.37	-0.80
A2	6 to 9 pm	[redacted]								
A3	6 to 9 pm									
A4	6 to 9 pm	68.3	334	1.13	748.1%	3.44	Yes	Yes	1.17	3.49
A5	4 to 9 pm	[redacted]								
B2	6 to 9 pm	71.8	145	1.63	9.3%	11.22	Yes	Yes	1.74	12.03

*All event hours fell in this window. Average event duration was one hour less than this window.

Figure 3-1 compares the settlement baseline (left panel) averaged across the average 6pm to 9pm weekday event to the ex post results (right panel) for the average 6pm to 9pm weekday event. The baseline loads shown are calculated at the individual customer level and then summed. As described above, the baseline (blue line in the left panel) is the average of the ten previous non-event days for each participant site. These days are individually selected for each participant site and are not necessarily the same days for all participant sites. The load impact counterfactual (blue line in the right panel) is the load modeled using site specific regression models with synthetic controls. The shape of the load impact counterfactual follows the shape of the observed event day participant site load shape relatively closely. The settlement baseline has a similar shape but is essentially pinned to the event day load in pre-event hours (as a result of the baseline adjustment). However, in both cases any impacts estimated are much smaller than the noise inherent in the loads, as indicated by the 90% confidence band in the load impact estimate (right panel).

Figure 3-1: ELRP A.1 Average Weekday 6-9pm Event Load Impact Compared to Baseline

Settlement Baseline - Aggregate (MW) **Load Impact Evaluation - Aggregate (MW)**



Incorporating a post event adjustment may somewhat reduce the gap in post event hours but would still not result in an adjusted load shape that follows event day loads in most non-event hours. In addition, the current baseline rules are asymmetrical and only allow for upward adjustments of the baseline. This means that the baseline could not be adjusted downwards to better align with post-event loads. Finally, there is always some amount of payment for noise with baseline settlements. This is exacerbated with asymmetric settlements and when actual impacts are not substantially higher than the noise inherent in the loads, or near zero as in PY 2023. One possible solution to this issue is implementation of a buffer or minimum percent impact which must be achieved in order for a settlement baseline to qualify for payment. This minimum would ideally be set above the noise observed in loads.

3.4 EX ANTE LOAD IMPACTS

A key objective of the 2023 evaluation is to quantify the relationship between demand reductions, temperature, and hour of day. Ex ante impacts are estimated load reductions as a function of weather conditions, time of day, and forecasted changes in enrollment. By design, they reflect planning conditions defined by normal (1-in-2) and extreme (1-in-10) peak demand weather conditions. The historical load patterns and performance during actual events are used as the reductions for a standardized set of weather conditions.

3.4.1 RELATIONSHIP OF CUSTOMER LOADS AND PERCENT REDUCTIONS TO WEATHER

When developing the ex ante forecast it is important to ask two questions:

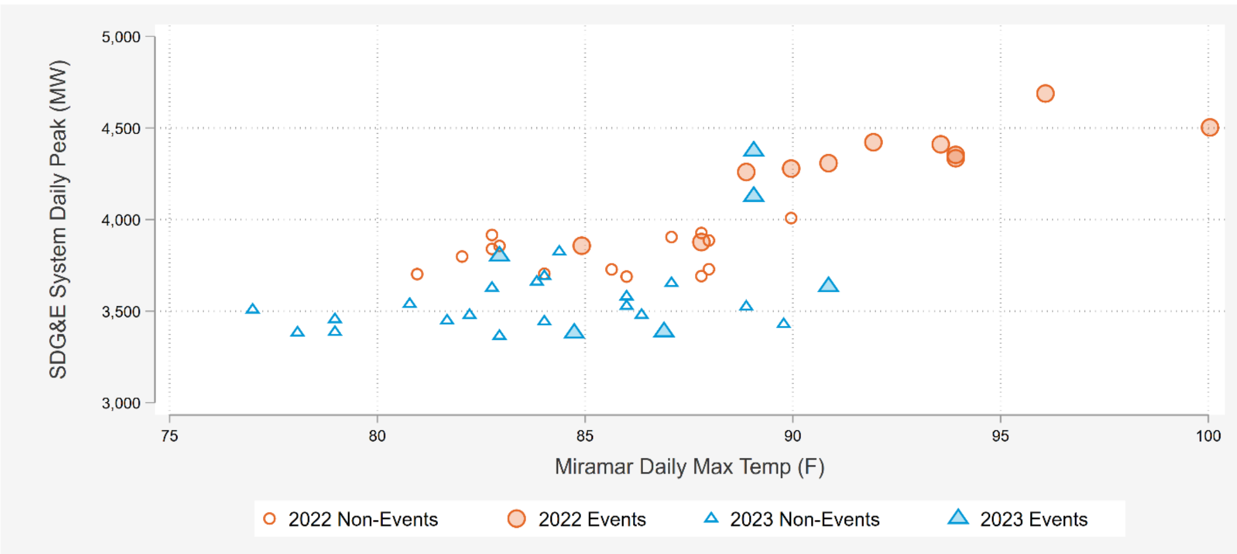
1. What are the most event relevant weather conditions for an emergency program such as ELRP?
2. How do observed impacts vary under those weather conditions?

The first question is important for determining which historical impacts should be used for developing the ex ante forecast. PY2023 ex post impacts were largely not significant across the non-residential subgroups. This stands in contrast to ex post results for PY2022 which yielded positive, significant reductions for A.1, [redacted], and B.2. In PY2023, A.1 retained its largest participants and has a similar set of participants as in PY2022, so the difference cannot be explained by changes in participation. Instead, the explanation likely lies in other differences between PY2022 and PY2023. Specifically, the weather conditions were cooler in 2023 and dispatch notifications were shorter for most events. On July 20th.and 25th there was one hour or less of advance notice and on July 26th there were just a few hours of advance notice, compared to day ahead notice provided in PY 2022.

Figure 3-2 compares system loads and maximum daily temperatures for the top 25 system load days for both years (2022 in orange and 2023 in blue), demonstrating that peak system loads were about 500

MW higher in 2022 and peak temperatures about 5 to 10 degrees higher at Miramar weather station[21]. This underscores the fundamental differences between the two years. PY2022 was an extreme weather year which saw not only ten ELRP events dispatched, most within the same week, but also a statewide phone notification sent from the California Office of Emergency Services on September 6, 2022. There was a relatively high level of awareness of the statewide emergency conditions, and this coincided with reductions. In contrast, there were no comparable emergency conditions in PY2023. Of the three ELRP events called for all non-residential subgroups, two were single hour events dispatched with an hour or less of advance notice and the third was dispatched with day-of notice. This contrasts to the day ahead notice provided for the PY2022 events, also a reflection of the extreme sustained conditions experienced in PY2022.

Figure 3-2: Summer System Loads and Max Daily Temperatures, 2022 and 2023



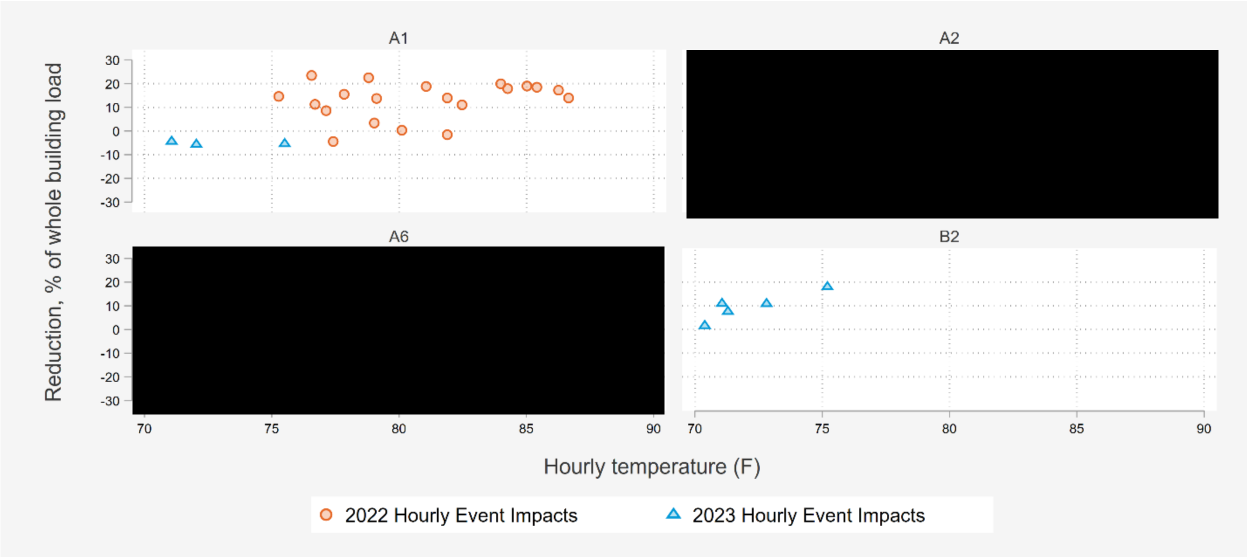
For these reasons, the impacts observed in PY2022 seem more reflective of what could be expected under emergency conditions. Because ELRP is an emergency program, the PY2023 ex ante forecast applied the emergency condition reductions from PY2022 rather than the reductions observed under the much milder PY2023 conditions.

The second question which should be asked when developing an ex ante weather model is how observed impacts vary under those weather conditions. Figure 3-3 shows the hourly percent reductions for historical weekday events as a function of hourly temperatures for sites in each ELRP subgroup[22].

[21] The weather station typically used for planning purposes.
[22] Impacts that are not statistically significant have been recoded to zero.

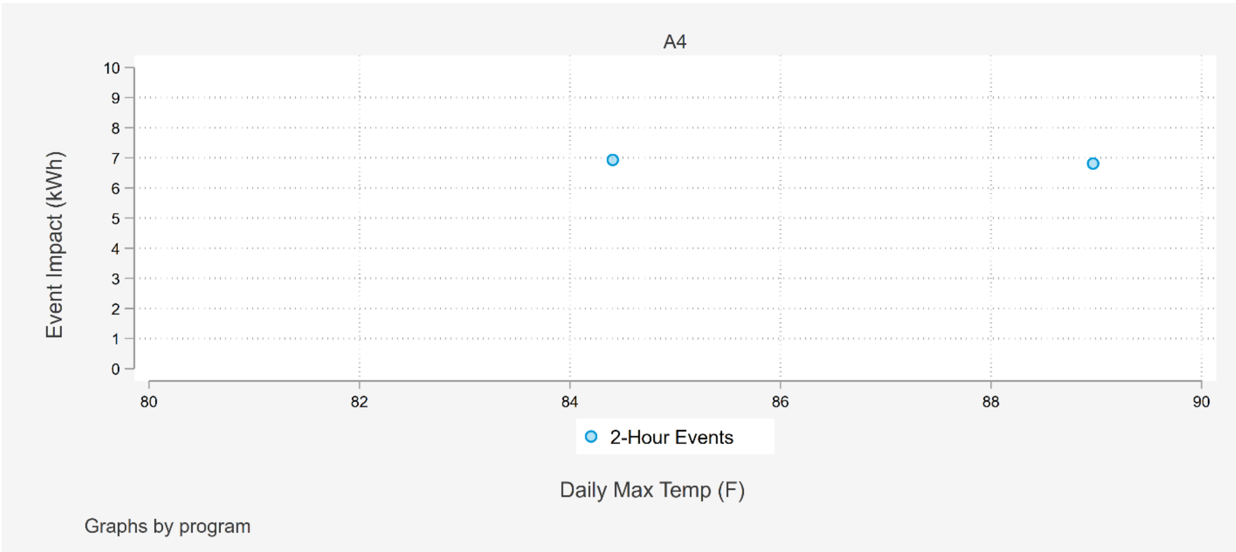
[redacted]

Figure 3-3: ELRP Hourly Reductions and Temperatures



For the A.4 subgroup, which is comprised of battery storage responding to dispatch signals, impacts can be assumed to be a function of the battery capacity made available by participants. Figure 3-4 shows the total kWh reduction for the average site for the two A.4 events. This is essentially the portion of the battery not reserved for on-site back-up. Though A.4 was only dispatched for two events in PY2023, analysis of ELRP A.4 events across other California IOUs revealed that the kWh reductions were relatively stable across event windows and durations. The two SDG&E events are not inconsistent with this finding. Therefore, it seems valid to assume that this pattern holds in the absence of additional data. This should continue to be assessed in future program years.

Figure 3-4: PY 2023 ELRP A4 Event kWh Reductions and Temperatures



3.4.2 Program Specific and Portfolio Adjusted Impacts

Program specific and portfolio adjusted impacts are developed for each subgroup. The fundamental difference that necessitates having these two sets of results is grounded in the ability of customers to participate in more than one energy saving program. Dual enrollments make proper attribution of savings estimates essential, to avoid double-counting. Ex post results are properly attributed by calculating the incremental impacts, or the load reduction beyond what was predicted or committed on dually called event hours. Modelling for ex ante is based solely on these incremental impacts.

Program specific ex ante estimates are the predicted savings generated by the population on days where only ELRP is called. Portfolio adjusted ex ante estimates are the population's incremental savings on days where eligible participants are called under both ELRP and the dually enrolled program. This distinction is analyzed since it can impact how participants respond to being called for an event.

Table 3-12 defines the dual enrolled programs for consideration in each subgroup.

Table 3-12: Eligible Dually Enrolled Programs for Ex Ante Considerations

ELRP Program	A1	A2	A3	A4	A5	A6	B2
Eligible Dually Enrolled Program	N/A[23]	N/A	N/A	AC Saver	AC Saver	Critical Peak Pricing[24]	Capacity Bidding Program

[23] While dual enrollment in Critical Peak Pricing is allowed, impacts on dual event days are allocated to ELRP
[24] Dual enrollment in supply side programs such as AC Saver not permitted for the A.6 subgroup

If there are no dual enrollments allowed or there were no dual events in a given season, the program impacts will equal the portfolio impacts.

3.4.3 Ex Ante Enrollment Forecast

To derive the aggregate forecast and reference loads, percent impacts per customer are scaled to the site population expected to be enrolled in each planning year. Table 3-13 summarizes the annual enrollments forecast for each subgroup through the approval year for each subgroup, e.g. 2025 for subgroup A.6 and 2027 for all other subgroups. Assumptions for the derivation of these forecasts are described below.

Table 3-13: Participant Enrollment Forecast

Year	Non-Residential					Residential		Total
	A1	A2	A3	A5	B2	A4	A6	
2023	649	[redacted]	[redacted]	[redacted]	166	335	567,613	568,768
2024	649	[redacted]	[redacted]	[redacted]	166	503	576,812	578,135
2025	649	[redacted]	[redacted]	[redacted]	166	754	590,513	592,087
2026	649	[redacted]	[redacted]	[redacted]	166	1,131	0	1,951
2027	649	[redacted]	[redacted]	[redacted]	166	1,696	0	2,516

For non-residential subgroups, enrollments in PY2023 were similar to PY2022, with a few exceptions that are not expected to continue in future years. First, participation in the A.1 subgroup was opened to small, non-residential sites and 141 new sites were added. Second, [redacted] A.2 participant moved to B.2. Third, an additional 42 participants enrolled in B2. Given the small population and the short timeframe for which ELRP has been an active program, enrollments were assumed to stay constant for future years, through 2027.

For the A.4 subgroup, 50% annual growth was assumed to be sustained through 2027. Though this is a relatively high growth rate, it is applied to a modest starting point of 335 participants in PY2023. The result is about 1,700 participants expected in PY2027.

For subgroup A.6, a separate enrollment forecast was developed for each eligibility group and incorporates:

- Expected new site enrollments per year
- Expected site attrition
- Expected site growth

Table 3-14 summarizes population, attrition, and enrollment growth assumptions used to derive the enrollment forecasts for PY2023, using the enrollment model described above. Note that PY2023 site enrollments are anchored to August. Attrition, which ranges between 0% and 2%, is applied annually and is based on the portion of participants retained as of October 2023 to reflect drops in enrollment after the event season. Growth rates are specific to each eligibility group. SDG&E does not plan to default enroll new BDR customers in the future, so the growth rate is assumed to be zero. The CARE/FERA population is assumed to grow by 1% annually (which roughly reflects overall population growth). SDG&E plans to continue default enrollment of new CARE / FERA customers, so the enrolled population is also assumed to grow by 1% annually. A different approach is used for the opted-in participants since they self-enroll in ELRP. In PY2022 about 0.7% of the population eligible for opting in to ELRP[25] enrolled. In PY2023, about 2% of the eligible population enrolled after a marketing campaign by SDG&E. As SDG&E continues to market ELRP to eligible customers, this rate of enrollment is assumed to continue annually until 5% of the total eligible population is enrolled. This is roughly the portion of the population that enrolled in SDG&E's Peak Time Rebate program, a similar opt-in load reduction program also based on individual settlement baselines.

Table 3-14: Residential ELRP Program Enrollment Forecast Assumptions

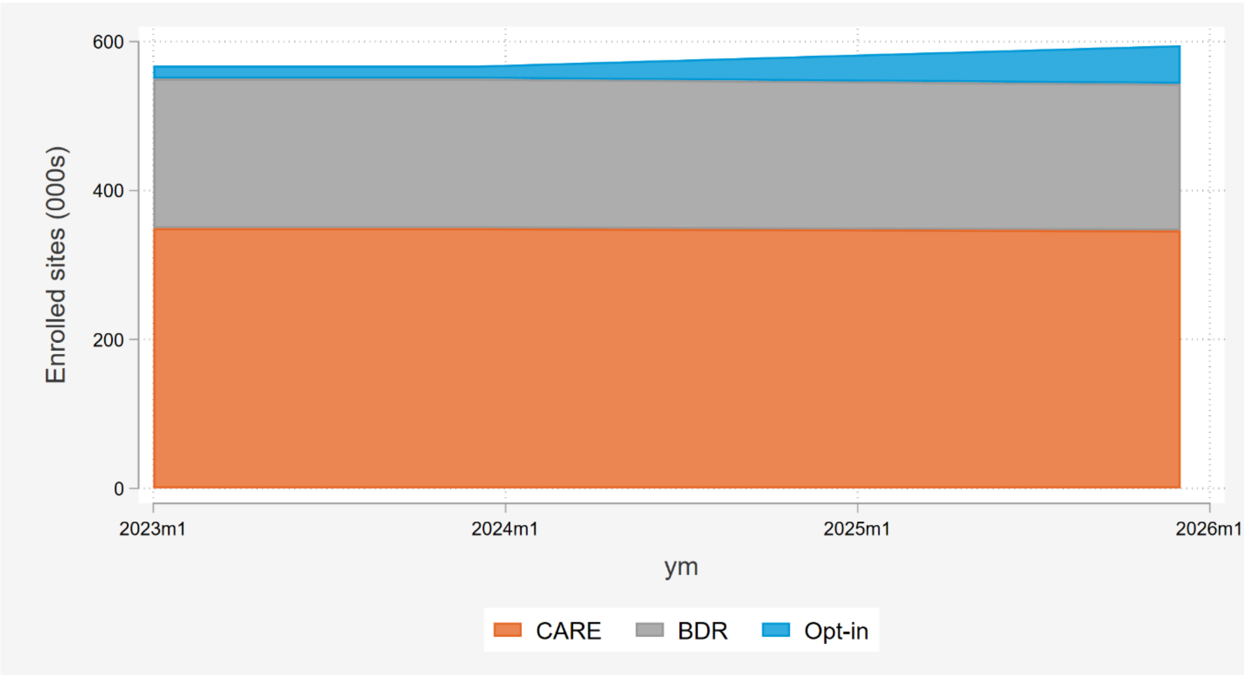
Eligibility Group	NEM	Enrolled population (Aug 2023)	Attrition (drop from 5/23 to 10/23)	Growth
BDR (not on CARE)	Yes	17,659	1.0%	0%
BDR (not on CARE)	No	183,215	0.7%	
CARE (includes linked to BDR)	Yes	34,098	1.5%	1% (e.g. population growth)
CARE (includes linked to BDR)	No	315,204	0.9%	
Self-enroll (Opt-in eligible)	Yes	3,405	2.0%	0.7% of eligible population enrolled in the first year. Incremental 2.0% enrolled in year 2. Assume incremental 2% enrolls each year until 5% total is enrolled
Self-enroll (Opt-in eligible)	No	14,032	2.2%	
TOTAL		567,613		

Figure 3-5 shows the resulting enrollment forecast by Residential ELRP eligibility group. Reflecting the assumptions above, the defaulted CARE / FERA population is suspected to grow slightly and the defaulted BDR population is expected to wane slightly, although both remain relatively steady over time and are expected to continue to represent the majority of the enrolled population. The opted-in population is expected to grow meaningfully but remain a relatively small share of the population. For

[25] About 550,000 customer sites not on CARE/FERA or BDR and not enrolled in other DR programs.

the purposes of monthly ex ante load estimates, changes in population are spread evenly from month to month.

Figure 3-5: Residential ELRP Enrollment Forecast



3.4.4 ELRP Group A.1 Ex Ante Load Impacts

Group A.1 is designated for non-residential customers not participating in DR programs and is currently the largest ELRP subgroup by far with over 400 participating sites. Table 3-15 summarizes the ex ante demand reduction capability by forecast year for different planning conditions. Table 3-16 shows the same for program specific impacts. Though dual enrollment with Critical Peak Pricing (CPP) is allowed, there is no difference between portfolio adjusted and program specific adjustments because impacts on ELRP-CPP dual event days, are attributed to ELRP. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions, which align with the planning conditions used for resource adequacy attribution. The ex post analysis showed no clear trend in percent load reductions relative to weather patterns so ex ante reductions are assumed to vary only as a function of the reference load. The static average percent reduction in each event hour is applied to this reference load.

This load impact forecast reflects reductions observed during PY 2022 emergency conditions. Enrollments are assumed to stay flat until the last year of ELRP approval in 2027, based on the enrollment forecast described above. Though 141 additional small commercial sites enrolled in PY2023 this growth is not assumed to persist in future years, so enrollments are assumed to stay flat until the last year of ELRP approval in 2027.

Table 3-15: Group A.1 Portfolio Adjusted Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	649	26.42	27.82	26.65	28.92
2024	649	26.42	27.82	26.65	28.92
2025	649	26.42	27.82	26.65	28.92
2026	649	26.42	27.82	26.65	28.92
2027	649	26.42	27.82	26.65	28.92

Table 3-16: Group A.1 Program Specific Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	649	26.42	27.82	26.65	28.92
2024	649	26.42	27.82	26.65	28.92
2025	649	26.42	27.82	26.65	28.92
2026	649	26.42	27.82	26.65	28.92
2027	649	26.42	27.82	26.65	28.92

3.4.5 ELRP Group A.2 Ex Ante Load Impacts

Group A.2 is designated for non-residential aggregators not participating in DR programs and was comprised of [redacted] in PY2023. Table 3-17 summarizes the ex ante demand reduction capability by forecast year for different planning conditions. Table 3-18 shows the same for program specific impacts. There is no difference between portfolio adjusted and program specific adjustments because there was no dual enrollment or dual-event days. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions, which align with the planning conditions used for resource adequacy attribution. [redacted]

[redacted]

Enrollments are assumed to stay flat until the last year of ELRP approval in 2027, based on the enrollment forecast described above.

Table 3-17: Group A.2 Portfolio Adjusted Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 3-18: Group A.2 Program Specific Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

3.4.6 ELRP Group A.3 Ex Ante Load Impacts

Group A.3 is designated for non-residential rule 21 exporting DERs not participating in DR programs and was comprised of [redacted] in PY2023. Table 3-19 summarizes the ex ante demand reduction capability by forecast year for different planning conditions. Table 3-20 shows the same for program specific impacts. There is no difference between portfolio adjusted and program specific adjustments because there was no dual enrollment or dual-event days. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions, which align with the planning conditions used for resource adequacy attribution. [redacted]

[redacted]

Enrollments are assumed to stay flat until the last year of ELRP approval in 2027, based on the enrollment forecast described above.

Table 3-19: Group A.3 Portfolio Adjusted Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 3-20: Group A.3 Program Specific Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

3.4.7 ELRP Group A.4 Ex Ante Load Impacts

Group A.4 is designated for Virtual Power Plant (VPP) aggregators of non-residential and residential battery storage. PY2023 enrollment consisted of one aggregator and 332 residential sites. Table 3-21 summarizes the ex ante demand reduction capability by forecast year for different planning conditions. Table 3-22 shows the same for program specific impacts. There is no difference between portfolio adjusted and program specific adjustments because there was no dual enrollment or dual-event days. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions, which align with the planning conditions used for resource adequacy attribution. The ex post analysis showed no trend in reductions by weather patterns and are therefore assumed to not be not weather sensitive. Load reductions are instead assumed to be a function of the total kWh reduction delivered by the average site for the average event, not reductions in weather sensitive loads. To derive expected impacts average kWh delivered during the PY2023 events is then divided by 3, to take into account the resource availability rules set to go into effect for PY2024.[26] Essentially, A.4 resources are required to provide three hours of reductions

[26] D.23-12-005 (521486520.PDF (ca.gov)) , section 11.1.9.1 page 142

during the 4pm to 9pm availability window, so it is assumed that the kWh reductions will be spread evenly across three hours. The resulting average kWh per hour is applied to all five hours of the RA window.

Enrollments are assumed to grow until the last year of ELRP approval in 2027, based on the enrollment forecast described above

Table 3-21: Group A.4 Portfolio Adjusted Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	335	0.77	0.77	0.77	0.77
2024	503	1.15	1.15	1.15	1.15
2025	754	1.73	1.73	1.73	1.73
2026	1,131	2.59	2.59	2.59	2.59
2027	1,696	3.88	3.88	3.88	3.88

Table 3-22: Group A.4 Program Specific Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	335	0.77	0.77	0.77	0.77
2024	503	1.15	1.15	1.15	1.15
2025	754	1.73	1.73	1.73	1.73
2026	1,131	2.59	2.59	2.59	2.59
2027	1,696	3.88	3.88	3.88	3.88

3.4.8 ELRP Group A.5 Ex Ante Load Impacts

Group A.5 is designated for non-residential vehicle-grid integration (VGI) aggregators not participating in DR programs and was comprised of [redacted] in PY2023. Table 3-23 summarizes the ex ante demand reduction capability by forecast year for different planning conditions. Table 3-24 shows the same for program specific impacts. There is no difference between portfolio adjusted and program specific adjustments because there was no dual enrollment or dual-event days. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions, which align with the planning conditions used for resource adequacy attribution. [redacted]

[redacted]
Enrollments are assumed to stay flat until the last year of ELRP approval in 2027, based on the enrollment forecast described above.

Table 3-23: Group A.5 Portfolio Adjusted Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 3-24: Group A.5 Program Specific Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

3.4.9 ELRP Group A.6 Ex Ante Load Impacts

Group A.6 is designated for residential customers not participating in DR programs and was comprised of approximately 568,000 participating sites in PY2023. Table 3-25 summarizes the ex ante demand reduction capability by forecast year for different planning conditions. Table 3-26 shows the same for program specific impacts. Portfolio adjusted impacts reflect impacts on dual ELRP-CPP event days in PY 2022 while and program specific reflect impacts on ELRP only event days. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions, which align with the planning conditions used for resource adequacy attribution. Since there were no A.6 events in PY2023, impacts from PY2022 were used to build the ex ante impact model. The ex post analysis showed no clear trend in percent load reductions relative to weather patterns so ex ante reductions are assumed to vary only as a function of the reference load. The static average percent reduction in each event hour is applied to this reference load. This calculation is performed for each eligibility group, since the reductions, reference loads, and forecasted enrollments all vary by eligibility group.

This load impact forecast reflects reductions observed during PY 2022 emergency conditions. Enrollments are assumed to stay flat until the last year of A.6 ELRP approval in 2025, based on the enrollment forecast described above.

Table 3-25: Group A.6 Portfolio Adjusted Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	567,613	11.95	13.52	12.70	14.26
2024	576,812	12.57	14.23	13.36	15.02
2025	590,514	13.49	15.29	14.35	16.16

Table 3-26: Group A.6 Program Specific Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	567,613	15.45	17.59	16.50	18.57
2024	576,812	16.14	18.40	17.24	19.44
2025	590,514	17.17	19.59	18.35	20.72

3.4.10 ELRP Group B.2 Ex Ante Load Impacts

Group B.2 is designated for IOU capacity bidding (CBP) PDR resources and was comprised of 145 participating sites in PY2023. Table 3-27 summarizes the ex ante demand reduction capability by forecast year for different planning conditions. Table 3-28 shows the same for program specific impacts. Portfolio adjusted impacts reflect incremental impacts on dual ELRP-CBP event days in PY 2022 while and program specific reflect impacts on ELRP only event days. The tables reflect dispatchable demand reductions available from 4 pm to 9 pm under August monthly peaking conditions for 1-in-2 and 1-in-10 weather conditions, which align with the planning conditions used for resource adequacy attribution. The ex post analysis showed no clear trend in percent load reductions relative to weather patterns so ex ante reductions are assumed to vary only as a function of the reference load. The static average percent reduction in each event hour is applied to this reference load.

Unlike the other subgroups, the B.2 populations changed meaningfully relative to PY2022, and substantial significant impacts were observed in PY2023 (roughly double the percent impacts observed in PY2022). This indicates fundamental differences in either the population or the aggregator implementation (or both) in PY2023, so it appears more appropriate to apply impacts from the PY2023 population. Enrollments are assumed to stay flat until the last year of ELRP approval in 2027.

Table 3-27: Group B.2 Portfolio Adjusted Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	166	1.57	1.66	1.61	1.72
2024	166	1.57	1.66	1.61	1.72
2025	166	1.57	1.66	1.61	1.72
2026	166	1.57	1.66	1.61	1.72
2027	166	1.57	1.66	1.61	1.72

Table 3-28: Group B.2 Program Specific Impacts for August Monthly Peak Day (MW)

Year	Sites	CAISO		SDG&E	
		1-in-2	1-in-10	1-in-2	1-in-10
2023	166	1.57	1.66	1.61	1.72
2024	166	1.57	1.66	1.61	1.72
2025	166	1.57	1.66	1.61	1.72
2026	166	1.57	1.66	1.61	1.72
2027	166	1.57	1.66	1.61	1.72

3.4.11 Comparison of Ex Post And Ex Ante Load Impacts

Table 3-29 compares the PY 2023 ex ante counterfactuals and demand reductions to the average across PY 2022 non-residential events[27]. These were used to develop the PY 2023 ex ante forecast since the PY 2023 ex post results mostly represent random variation. In PY 2022 the average event was also called from 4 to 9pm but in PY 2023 shorter events were called. Ex ante results are shown for the 4pm to 9pm resource adequacy window and compared to the average PY2022 weekday event for the same time period, to ensure comparability of loads. In 2022, non-residential ELRP customers delivered 9.1% in load reductions (19.89 MW) for the average event which was also called from 4 to 9pm. Ex ante reductions for the 4 to 9pm resource adequacy window, which happened to align with the event window, were 10.9% and therefore similar to ex post reductions. Differences in ex ante and ex post counterfactual loads (Load without DR) are largely explained by the lower PY 2022 ex post enrollment as compared to PY 2023 ex ante. The SDG&E and CAISO weather ex ante predictions are slightly different because ex ante reference loads are assumed to be weather sensitive. Percent impacts are

[27] PY 2023 results are used for B2 since those are what was used for the PY 2023 ex ante estimates for that subgroup

equal across the two ex ante weather specifications because no weather trend was established for impacts.

Table 3-29: Non-Residential ELRP[28] Comparison of Ex Post and Ex Ante Load Impacts for 2023

Result Type	Day Type and Period	Sites	Load without DR (MW)	Load Reduction (MW)	% Reduction	Event Avg Temp (F)
Ex Post Avg. Weekday (PY 2022)	Resource Adequacy Period (4 to 9 pm)	633	219.47	19.89	9.1%	79.9
Ex ante SDG&E	1-in-2 Weather August Peak (4 to 9 pm)	820	259.78	28.23	10.9%	83.5
Ex ante CAISO	1-in-2 Weather August Peak (4 to 9 pm)	820	257.34	27.96	10.9%	81.1

Table 3-30 compares the demand reductions from 2023 A.4 events. Results are shown for the 4pm to 9pm resource adequacy window and compared to the average PY2023 weekday event. ELRP A.4 customers delivered 0.34 MW in 2023 on average across the 4 to 9pm period which is shown here to facilitate comparison to the ex ante estimates. This corresponds to 1.7 MWh in total across the 5 hour window. Average ex post impacts for PY 2023 were actually closer to 2.3 MWh, but there was some negative reduction in the pre-event hours due to batteries delaying TOU response otherwise observed on non-event days. To derive expected ex ante impacts, average MWh delivered during the PY2023 events is divided by 3, to take into account the resource availability rules set to go into effect for PY2024.[29] Essentially, A.4 resources are required to be to provide three hours of reductions during the 4pm to 9pm availability window, so it is assumed that the kWh reductions will be spread evenly across three hours. The resulting average MWh per hour is applied to all five hours of the RA window. The resulting ex ante impact is 0.77 MW per hour, or 2.3 MWh over three hours, which aligns well with the ex post result.

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[28] A.1, A.2, A.3, A.5, B.2

[29] D.23-12-005 (521486520.PDF (ca.gov)) , section 11.1.9.1 page 142

Table 3-30: A4 Battery ELRP Comparison of Ex Post and Ex Ante Load Impacts for 2023

Result Type	Day Type and Period	Sites	Load without DR (MW)	Load Reduction (MW)	% Reduction	Event Avg Temp (F)
Ex Post Average Weekday (PY 2023)	Resource Adequacy Period (4 to 9 pm)	331	-0.08	0.34	-443.5%	73.4
Ex ante SDG&E	1-in-2 Weather August Peak (4 to 9 pm)	335	-0.15	0.77	-501.4%	83.2
Ex ante CAISO	1-in-2 Weather August Peak (4 to 9 pm)	335	-0.17	0.77	-450.2%	80.9

Table 3-31 compares the demand reductions from 2022 A.6 events, since no events were called in PY2023. Ex ante results are shown for the 4pm to 9pm resource adequacy window and compared to the loads and impacts for the average PY 2022 weekday event day, during the 4 to 9pm window which also corresponded to the event window. Loads, percent impacts, and enrollments are very similar between PY 2022 ex post and PY 2023 ex ante, with moderate differences due to a slight increase in enrollments in 2023, including proportionately more opt-in participants with higher impacts.

Table 3-31: A6 Residential ELRP Comparison of Ex Post and Ex Ante Load Impacts for 2023

Result Type	Day Type and Period	Sites	Load without DR (MW)	Load Reduction (MW)	% Reduction	Event Avg Temp (F)
Ex Post Average Weekday (PY 2022)	Resource Adequacy Period (4 to 9 pm)	525,420	628.07	11.91	1.9%	78.3
Ex ante SDG&E	1-in-2 Weather August Peak (4 to 9 pm)	567,613	642.12	12.70	2.0%	82.7
Ex ante CAISO	1-in-2 Weather August Peak (4 to 9 pm)	567,613	602.72	11.95	2.0%	80.6

3.4.12 Ex Ante Load Impact Slice-of-Day Tables

Table 3-32, Table 3-33, Table 3-34, Table 3-35, Table 3-36, Table 3-37, and Table 3-38 show the 2023 ex ante aggregate hourly impacts by ELRP Group for each month under SDG&E 1-in-2 monthly peaking conditions. The tables are designed to enable the CPUC's Slice-of-Day Resource Adequacy requirements. Currently the ELRP pilot does not qualify for Resource Adequacy, but these tables reflect what the slice of day load impacts would look like if ELRP did qualify for Resource Adequacy. The estimated reductions are typically larger in the hotter summer months and smaller in the cooler winter months. For Group A.4, response to an event is flat across the five-hour Resource Adequacy window to reflect consistent battery discharge. For other groups, however, event response varies by hour.

Table 3-32: Group A.1 Slice of Day Table for Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	22.41	22.41	0.00	0.00	0.00	25.14	27.62	27.89	29.51	27.50	25.75	22.41
18	20.33	20.33	20.33	24.02	23.26	23.64	27.34	27.44	29.97	27.36	24.88	20.33
19	19.93	19.93	19.93	23.31	22.61	22.96	26.39	26.44	28.79	26.42	24.13	19.93
20	19.80	19.80	19.80	22.91	22.26	22.59	25.78	25.82	28.01	25.79	23.67	19.80
21	19.21	19.21	19.21	22.53	21.79	22.09	25.66	25.65	28.15	25.76	23.43	19.21
22	0.00	0.00	19.29	22.52	21.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)
Load increases are negative (Orange)

Table 3-33: Group A.2 Slice of Day Table for Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	[redacted]											
2	[redacted]											
3	[redacted]											
4	[redacted]											
5	[redacted]											
6	[redacted]											
7	[redacted]											
8	[redacted]											
9	[redacted]											
10	[redacted]											
11	[redacted]											
12	[redacted]											
13	[redacted]											
14	[redacted]											
15	[redacted]											
16	[redacted]											
17	[redacted]											
18	[redacted]											
19	[redacted]											
20	[redacted]											
21	[redacted]											
22	[redacted]											
23	[redacted]											
24	[redacted]											

Demand reductions are positive (Blue)
Load increases are negative (Orange)

Table 3-34: Group A.3 Slice of Day Table for Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	[redacted]											
2	[redacted]											
3	[redacted]											
4	[redacted]											
5	[redacted]											
6	[redacted]											
7	[redacted]											
8	[redacted]											
9	[redacted]											
10	[redacted]											
11	[redacted]											
12	[redacted]											
13	[redacted]											
14	[redacted]											
15	[redacted]											
16	[redacted]											
17	[redacted]											
18	[redacted]											
19	[redacted]											
20	[redacted]											
21	[redacted]											
22	[redacted]											
23	[redacted]											
24	[redacted]											

Demand reductions are positive (Blue)
Load increases are negative (Orange)

Table 3-35: Group A.4 Slice of Day Table for Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.77	0.77	0.00	0.00	0.00	0.77	0.77	0.77	0.77	0.77	0.77	0.77
18	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77
19	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77
20	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77
21	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77
22	0.00	0.00	0.77	0.77	0.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	-0.04	-0.04	0.00	0.00	0.00	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04
24	0.00	0.00	-0.04	-0.04	-0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)
Load increases are negative (Orange)

Table 3-36: Group A.5 Slice of Day Table for Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	[redacted]											
2	[redacted]											
3	[redacted]											
4	[redacted]											
5	[redacted]											
6	[redacted]											
7	[redacted]											
8	[redacted]											
9	[redacted]											
10	[redacted]											
11	[redacted]											
12	[redacted]											
13	[redacted]											
14	[redacted]											
15	[redacted]											
16	[redacted]											
17	[redacted]											
18	[redacted]											
19	[redacted]											
20	[redacted]											
21	[redacted]											
22	[redacted]											
23	[redacted]											
24	[redacted]											

Demand reductions are positive (Blue)
Load increases are negative (Orange)

Table 3-37: Group A.6 Slice of Day Table for Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.40	0.40	0.40	1.10	1.02	1.18	1.62	1.79	2.01	1.51	1.09	0.40
13	0.16	0.16	0.16	1.13	1.01	1.24	1.91	2.16	2.52	1.75	1.11	0.16
14	0.04	0.04	0.04	1.29	1.13	1.43	2.37	2.70	3.20	2.15	1.28	0.04
15	0.05	0.05	0.05	1.58	1.36	1.73	2.96	3.36	4.02	2.70	1.59	0.05
16	0.26	0.26	0.26	2.00	1.74	2.17	3.62	4.06	4.86	3.32	2.03	0.26
17	1.33	1.33	1.33	3.90	3.53	4.18	6.28	6.94	8.09	5.83	3.94	1.33
18	3.17	3.17	3.17	6.45	6.00	6.82	9.43	10.28	11.70	8.84	6.46	3.17
19	5.33	5.33	5.33	9.07	8.56	9.52	12.44	13.43	15.04	11.78	9.08	5.33
20	7.26	7.26	7.26	11.02	10.51	11.47	14.42	15.40	17.03	13.75	11.03	7.26
21	9.06	9.06	9.06	12.96	12.43	13.39	16.46	17.44	19.14	15.78	12.99	9.06
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)
Load increases are negative (Orange)

Table 3-38: Group B.2 Slice of Day Table for Monthly Peak Day (Aggregate Impacts (MW))

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	1.34	1.34	0.00	0.00	0.00	1.72	2.00	2.08	2.25	1.97	1.73	1.34
18	1.31	1.31	1.47	1.78	1.73	1.59	1.80	1.85	1.98	1.77	1.60	1.31
19	1.21	1.21	1.39	1.65	1.61	1.45	1.62	1.67	1.77	1.60	1.45	1.21
20	1.04	1.04	1.22	1.42	1.40	1.23	1.36	1.40	1.48	1.34	1.22	1.04
21	0.82	0.82	0.99	1.12	1.11	0.95	1.03	1.05	1.10	1.01	0.94	0.82
22	0.00	0.00	0.70	0.81	0.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)
Load increases are negative (Orange)

4 CONCLUSIONS AND RECOMMENDATIONS

The non-residential ELRP pilots largely did not deliver statistically significant demand reductions in PY2023 while the A.4 residential battery storage pilot did deliver substantial significant savings. For both pilots there is room for improvement. The recommendations below may not be currently funded and may not be within SDG&E's control, and costs and feasibility need to be considered alongside other research and program priorities.

4.1 ELRP RECOMMENDATIONS

- **Reserve ELRP dispatch for clear emergency conditions.** Significant load reductions were observed for PY2022 and largely not for PY2023 events. PY 2022 events were also dispatched under more extreme conditions and may be more a function of the emergency conditions under which the event is called. Unlike in PY 2022, in PY 2023 there were no emergency conditions or resulting public service announcements to improve customer awareness of the events. Reserving dispatch to clear emergency conditions which are clearly communicated to participants may be more in line with participant expectations and understanding of the program and may deliver greater impacts when it is called. This may include not calling event in years where extreme weather conditions are not experienced.

- **Improve dispatch advance notice.** PY2022 events were also with day-ahead notice, compared to day-of and even hour-ahead notice in PY2023. The advance notice received by participants, which is a function of when CAISO Emergency Energy Alerts are triggered may also indirectly be a function of extremity of emergency conditions at the time of the alert. To the extent possible, earlier advance notice, ideally day ahead, should improve response to ELRP event notifications.

- **Consider updates to baseline adjustment rules.** While a load impact evaluation approach which incorporates controls for exogenous factors provides the most robust estimate of actual load reductions, ELRP participant sites are paid for reductions based on baseline methodology. This includes a pre-event adjustment which is asymmetrical because it can only adjust the baseline upwards, not downwards. Incorporating a post event adjustment may somewhat reduce the gap observed between the adjusted baseline and observed loads in post event hours. Incorporating symmetrical adjustment rules would allow for downwards adjustment for better alignment with post-event loads. Further, to avoid payment for noise with baseline settlements the settlement rules could incorporate a buffer or minimum percent impact which must be achieved in order for a settlement baseline to qualify for payment. This minimum would ideally be set above the noise observed in loads.

APPENDIX

A. INDIVIDUAL SITE REGRESSIONS WITH SYNTHETIC CONTROLS

Individual site regressions with synthetic controls and site-specific specifications were used as a supplementary method for estimating load impacts for PY 2023 impacts for Non-Residential ELRP. The approach is implemented on hourly participant site loads. It relies on control sites that did not experience the intervention (up to five matched to each participant site), lagged participant site usage, an industry usage profile, solar irradiance, plus weather and time characteristics, to estimate the counterfactual. The model estimates a counterfactual load using weather and these various synthetic controls and predictors. A separate model is estimated for each hour of day and all modeling excludes event days. Reductions are the difference between the observed participant site and predicted counterfactual loads. With a regression model with synthetic controls, one should observe:

- Very similar energy use patterns for participant site and counterfactual loads when the intervention is not in place.
- A change in demand patterns for customers who are dispatched or subject to time varying prices, but no similar change for the counterfactual load.
- The timing of the change should coincide with the introduction of intervention.

The use of individually specified site-specific regression models allows for incorporation of a subset of possible parameters that best predict out of sample loads for each site and does not rely on finding a single ideal match. The functional form of the regression with synthetic controls differs from a panel difference in difference regression in that usage for the control or controls are specified as right hand predictor variables. This enables the incorporation of multiple controls and the magnitude of coefficients for each control essentially weights the effect of each control in the regression which directly estimates the counterfactual load. In a difference in difference regression, usage for the single matched control is structured on a separate record from the treatment site and a treatment effect is instead estimated. The counterfactual load is then derived by adding back the treatment effect to the observed load. The model equation including the full set up possible parameters is presented below in Equation A 0-1 and Table A 0-1. In practice the model used for each site and included a varying subset of these parameters. A separate model was estimated for each hour of the day.

Equation A 0-1: Ex Post Regression Model for Non-Residential ELRP

$$kW_t = \mathrm{a} + \sum_{n=1}^{max} \mathrm{b} \cdot kW\_0_{n,t} + \sum_{n=1}^{max} \mathrm{c}_n \cdot kW\_1_{t-n} + \sum_{n=1}^{max} \mathrm{d}_n \cdot month_n + \sum_{n=1}^{max} \mathrm{e}_n \cdot dow_n + \mathrm{f} \cdot solar_t + \mathrm{g} \cdot industry_t + \sum_{n=1}^{max} \mathrm{h}_{n,t} \cdot spline_{n,t} + \delta_t + \varepsilon_{i,t}$$

Where:

Table A 0-1: Ex Post Regression Elements for Non-Residential ELRP

kW_t	Is the site usage for each time period.
kW_0_t	Is the synthetic control usage for up to 5 matched controls for each time period. The specific number of controls used varied by site. These synthetic controls were selected based on Euclidean distance matching (the winning matching method in a tournament of 8 methods). They did not experience the treatment.
kW_1_{t-n}	Is the lagged participant site usage and could by one of: no lags, 1 day, 1 week, 2 weeks, 1 day and 1 week, and 1 and 2 weeks. The specific lags used varied by site.
a	Is the model intercept.
b	Coefficients for the synthetic control loads. The specific number of controls used varied by site and ranged from 0 to 5.
c	Coefficients for the participant site usage lags. The specific lags used varied by site.
d	Coefficients for each month.
e	Coefficients for each day of week.
f	Coefficient for solar irradiance across for each time period. Inclusion of this parameter varied by site.
g	Coefficient for industry load profile: normalized hourly loads (scaled from 0 to 1) for control sites in the same industry as the participant site. Industry grouping developed using NAICS code and customer names indicative of industry activity. Inclusion of this parameter varied by site.
h	Coefficients for weather sensitivity of loads, based on a 2 knot spline of 24 hour moving average of temperature, averaged across participant sites for each time period.
δ_t	Represents time effects for each time period. This accounts for observed and unobserved factors that vary by time but affect all customers equally.
$\varepsilon_{i,t}$	Represents the error term for each individual customer and time period.