PG&E 2022 ELRP (EMERGENCY LOAD REDUCTION PROGRAM) LOAD IMPACT REPORT

CALMAC ID- PGE0486

FINAL

Submitted to:
Pacific Gas and Electric Company

Prepared by:
Ethan Barquest, Collin Elliot, Jean Shelton
of
Verdant Associates, LLC

Public Version. Redactions in PY 2022 PG&E ELRP Load Impact Evaluation Report and Appendices

-------------Confidential Content Removed and Blacked Out -------------

Verdant Associates, LLC
Berkeley, CA 94707
www.verdantassoc.com

April 3, 2023

Public Version. *Confidential content removed and blacked out.*

TABLE OF CONTENTS

1 EXECUTIVE SUMMARY ... 1

1.1 PARTICIPANT CHARACTERISTICS ... 2
1.2 EVENT INFORMATION ... 3
1.3 METHODOLOGY ... 3
1.3.1 Ex Post Methodology ... 3
1.3.2 Ex Ante Methodology ... 4
1.4 EX POST IMPACTS ... 5
1.4.1 Average Event Day Load Shapes ... 10
1.5 EX ANTE IMPACTS ... 13

2 INTRODUCTION ... 15

2.1 EVALUATION OBJECTIVES ... 16
2.2 PARTICIPANT CHARACTERISTICS ... 16
2.3 EVENT INFORMATION ... 25
2.4 REPORT ORGANIZATION ... 27

3 DATA AND METHODS ... 28

3.1 DATA SOURCES ... 28
3.1.1 PG&E Participant Data Attrition ... 29
3.2 EX POST IMPACT METHODOLOGY ... 31
3.2.1 Subgroups A.1, A.2, and B.2 ... 32
3.2.2 Subgroup A.4 VPP ... 32
3.2.3 Subgroup A.6 Residential ... 32
3.2.4 Ex Post Analysis Framework ... 38
3.2.5 Impact Estimation for Subgroups A.1, A.2 and B.2 ... 42
3.2.6 Impact Estimation for Subgroup A.4 ... 44
3.2.7 Impact Estimation for Subgroups A.6 ... 45
3.3 EX ANTE IMPACT METHODOLOGY ... 47
3.3.1 Ex Ante Impacts - Non.A.6 ... 48
3.3.2 Ex Ante Impacts A.6 ... 49
3.3.3 Ex Ante Forecasts ... 49
3.3.4 COVID-19 Ex Ante Adjustments ... 50
3.4 UNCERTAINTY ADJUSTED IMPACTS ... 50
3.5 USE OF NET AND DELIVERED LOAD ... 51
3.6 MODELING CHALLENGES ... 51

4 EX POST RESULTS ... 52

4.1 SUBGROUP A.1 BIP EVENT DAY IMPACTS ... 53
4.1.1 Subgroup A.1 BIP ELRP-Only Event Day Load Shape ... 54
4.1.2 Subgroup A.1 BIP Average Event Day Impacts by Domain ... 55
4.2 SUBGROUP A.1 GENERAL EVENT DAY IMPACTS ... 57
4.2.1 Subgroup A.1 General Average Event Day Impacts by Domain ... 58
4.2.2 Subgroup A.1 General PDP Dually Enrolled Event Day Impacts ... 61

4.3 SUBGROUP A.2 BIP EVENT DAY IMPACTS 63
4.3.1 Subgroup A.2 BIP ELRP-Only Event Day Load Shape 65
4.3.2 Subgroup A.2 BIP Average Event Day Impacts by Domain 66
4.4 SUBGROUP A.4 VPP EVENT DAY IMPACTS 68
4.4.1 Subgroup A.4 Event Day Load Reduction Behaviors 69
4.4.2 Subgroup A.4 VPP Event Day Load Impacts 72
4.4.3 Subgroup A.4 Average Event Day Impacts by Domain 72
4.5 SUBGROUP A.6 RESIDENTIAL EVENT DAY IMPACTS 75
4.5.1 Subgroup A.6 Residential Average Event Day Impacts by Enrollment Group 77
4.5.2 Subgroup A.6 Residential Flex Alert vs. ELRP Load Reduction Contributions 79
4.5.3 Subgroup A.6 Residential Average Event Day Impacts Dually Enrolled Customers 81
4.6 SUBGROUP B.2 CBP AGGREGATOR EVENT DAY IMPACTS 83
4.7 AVERAGE EVENT DAY AGGREGATE IMPACTS BY HOUR 88
4.8 ELRP NOMINATIONS VS EX POST IMPACTS 97

5 EX ANTE IMPACTS 99

5.1 PG&E EX ANTE IMPACTS A.1 BIP 99
5.2 PG&E EX ANTE IMPACTS A.1 GENERAL 101
5.3 PG&E EX ANTE IMPACTS A.2 BIP 103
5.4 PG&E EX ANTE IMPACTS A.4 VPP 105
5.5 PG&E EX ANTE IMPACTS A.6 RESIDENTIAL 107
5.5.1 A.6 Residential Ex Ante Impacts – Negative per capita Impact Correlation with Temperature 110
5.6 PG&E EX ANTE IMPACTS B.2 CBP AGGREGATOR 111
5.7 PG&E TOTAL ELRP EX ANTE FORECASTS PY 2023 THROUGH PY 2025 112

6 EX POST AND EX ANTE COMPARISONS 115

6.1 PY 2022 EX POST VERSUS PY 2021 EX POST 115
6.2 PY 2022 EX POST VERSUS PY 2021 EX ANTE 116
6.3 PY 2022 EX ANTE VERSUS PY 2021 EX ANTE – ESTIMATES FOR 2023 116
6.4 PY 2022 EX POST VERSUS PY 2022 EX ANTE FOR PY 2023 117

7 FINDINGS AND RECOMMENDATIONS 119

APPENDIX A TABLE GENERATORS 121

APPENDIX B PROXY DAY TESTING PERFORMANCE 122

B.1 PERFORMANCE METRICS 124
B.2 ACTUAL VS PREDICTED PROXY DAY LOAD SHAPES 126

LIST OF FIGURES

Figure 1-1: PG&E Group A.6 Average Event Day Per Capita Load Impacts Contribution - Flex Alert vs. ELRP 9

Figure 1-2: PG&E Average Event Day Aggregate Load Impact – Subgroup A.1 BIP 10

Figure 1-3: PG&E Average Event Day Aggregate Load Impact – Subgroup A.1 General 11

Figure 1-4: PG&E Average Event Day Aggregate Load Impact – Subgroup A.2 BIP 11

Figure 1-5: PG&E Average Event Day Aggregate Load Impact – Subgroup A.4 VPP 12

Figure 1-6: PG&E Average Event Day Aggregate Load Impact – Subgroup A.6 Residential 12

Figure 1-7: PG&E Average Event Day Aggregate Load Impact – Subgroup B.2 CBP Aggregator 13

Figure 1-8: PG&E 1-in-10 (right) and 1-in-2 (Left) Utility Typical Event Day Ex Ante Aggregate Impacts by Program year and ELRP Subgroup 14

Figure 2-1: A.1 BIP Participant Counts by Population Characteristic Type 19

Figure 2-2: A.1 General Participant Counts by Population Characteristic Type 20

Figure 2-3: A.2 BIP Participant Counts by Population Characteristic Type 21

Figure 2-4: A.4 VPP Participant Counts by Population Characteristic Type 22

Figure 2-5: A.6 Residential Participant Counts by Population Characteristic Type 23

Figure 2-6: B.2 CBP Aggregator Particiant Counts by Population Characteristic Type 24

Figure 3-1: Propensity Score Matching Example 36

Figure 3-2: Load Profile Validation for NEM (RIght) and Non-NEM (Left) SPSM Control Group 38

Figure 3-3: Ex Post Impact Model Arbitration 42

Figure 3-4: Subgroup A.6 Residential Modeling Outcomes 46

Figure 3-5: Example of SmartRate™ Participant Incremental Load Reduction Baselines 47

Figure 4-1: PG&E Average Event Day Aggregate Load Impact – Subgroup A.1 BIP 53

Figure 4-2: PG&E A.1 BIP Average Per Capita Load Shape – ELRP Only Event Days 55

Figure 4-3: PG&E Average Event Day Aggregate Load Impact – Subgroup A.1 General 58

Figure 4-4: PG&E Average Event Day Per Capita Load Impact – Subgroup A.1 General PDP Dually enrolled 62

Figure 4-5: PG&E Average Event Day Aggregate Load Impact – Subgroup A.2 BIP 64

Figure 4-6: PG&E Average ELRP only Days Per Capitia Load Impact – Subgroup A.2 BIP – Delivered Load 66

Figure 4-7: PG&E Average Event Day Aggregate Load Impact – Subgroup A.4 VPP 69

Figure 4-8: PG&E Subgroup A.4 VPP Event Day Dispatch Behaviors 70

Figure 4-9: PG&E Subgroup A.4 VPP Consecutive Event Day Pre-Charging Behavior 71

Figure 4-10: PG&E Average Event Day Aggregate Load Impact – Subgroup A.6 Residential 76

Figure 4-11: PG&E Average Event Day Per Capita Load Impact by A.6 Residntial Enrollment Group – Delivered Load 78

Figure 4-12: PG&E Subgroup A.6 Residential Average Event Day Per Capita Load Impacts Contribution - Flex AlerT vs. ELRP 80

Figure 4-13: PG&E A.6 Residential Average Event Day Aggregate Load Impact – Dually Enrolled SmartRate™ 82

Figure 4-14: PG&E Average Event Day Aggregate Load Impact – Subgroup B.2 CBP Aggregator 84

Figure 4-15: PG&E PY 2022 Group A.1 BIP Nominations Vs. Ex Post Impacts 97

Figure 4-16: PG&E PY 2022 Group A.1 General Nominations Vs. Ex Post Impacts 97

Figure 5-1: PG&E Portfolio and Program Utility 1-in-2 Typical Event Day Per Capita Load Shape – Subgroup A.1 BIP 100

Figure 5-2: PG&E Portfolio and Program Utility 1-in-2 Typical Event Day Per Capita Load Shape – Subgroup A.1 General 101

Figure 5-3: PG&E Portfolio and Program Utility 1-in-2 Typical Event Day Per Capita Load Shape – Subgroup A.1 General - PDP Dually Enrolled 102

Figure 5-4: PG&E Portfolio and Program Utility 1-in-2 Typical Event Day Per Capita Load Shape – Subgroup A.2 BIP - Delivered Load 104

Figure 5-5: PG&E Portfolio and Program Utility 1-in-2 Typical Event Day Per Capita Load Shape – Subgroup A.4 VPP 106

Figure 5-6: PG&E Portfolio and Program Utility 1-in-2 Typical Event Day Per Capita Load Shape – Subgroup A.6 Residential 107

Figure 5-7: PG&E Portfolio Adjusted 1-in-2 Typical Event Day Per Capita Load Shape – Subgroup A.6 Residential By Enrollment Group - Delivered Load 109

Figure 5-8: PG&E Residential A.6 Utility System Peak Ex Ante Per Capita Impacts by Temperature 110

Figure 5-9: PG&E Portfolio and Program Utility 1-in-2 Typical Event Day Per Capita Load Shape – Subgroup B.2 CBP Aggregator 111

Figure 5-10: PG&E 1-in-10 (right) and 1-in-2 (Left) Utility Typical Event Day Ex Ante Aggregate Impacts by Program year and ELRP Subgroup 114

Figure B-1: PG&E Proxy Day Actual vs. Predicted Load – A.1 BIP 126

Figure B-2: PG&E Proxy Day Actual vs. Predicted Load – A.1 General 126

Figure B-3: PG&E Proxy Day Actual vs. Predicted Load – A.2 BIP 127

Figure B-4: PG&E Proxy Day Actual vs. Predicted Load – A.4 VPP 127

Figure B-5: PG&E Proxy Day Actual vs. Predicted Load NEM (Right) and Non-NEM (Left) – A.6 Residential 128

Figure B-6: PG&E Proxy Day Actual vs. Predicted Load – AB.2 CBP Aggregator 128

LIST OF TABLES

Table 1-1: Active PY2022 ELRP Customer Enrollment Counts 2

Table 1-2: PY 2022 PG&E ELRP Event Information 3

Table 1-3: PG&E 2022 ELRP Average Event Hour Impacts by Group 6

Table 1-4: PG&E Group A.6 ELRP Average Event Day Impacts by Enrollment Type 9

Table 1-5: Utility 1-in-10 Typical Event Day Ex Ante Aggregate Impacts by Program year and ELRP Subgroup – Portfolio Adjusted 13

Table 1-6: Utility 1-in-2 Typical Event Day Ex Ante Aggregate Impacts by Program year and ELRP Subgroup – Portfolio Adjusted 14

Table 2-1: Active PY2022 ELRP Customer Enrollment Counts 17

Table 2-2: ELRP DUAL Enrollment By Subgroup and Program 17

Table 2-3: PY 2022 PG&E ELRP Event Information 25

Table 2-4: PY 2022 PG&E Dual Program Event Days for Dually Enrolled ELRP Particpants 26

Table 3-1: PG&E Non-A.6 Data Attrition by Event Day and Subgroup 30

Table 3-2: Ex Post Impact Reporting Domains of Interest by Subgroup 31

Table 3-3: Participant and Non-Participant Population Premise Counts 33

Table 3-4: Summary of T-Tests Results from Hourly SPSM Matching for PG&E A.6 37

Table 3-5: Count and Share of Particpants Exihibiting Weather Sensitivity by Subgroup 39

Table 3-6: Variable Types Included in Candidate Specification Modeling Groups 40

Table 3-7: PG&E Ex Ante Participant Enrollment Forecast by Year Subgroup 50

Table 3-8: PG&E Ex Ante Covid-19 Baseline Adjustment Factors by Month and Sector 50

Table 4-1: PG&E PY 2022 ELRP Average Event Hour Impact – Subgroup A.1 BIP 54

Table 4-2: PG&E Subgroup A.1 BIP Average Event Day Impacts by Geography Domains 56

Table 4-3: PG&E Subgroup A.1 BIP Average Event Day Impacts by Particpant Characteristics 57

Table 4-4: PG&E PY 2022 ELRP Average Event Hour Impact – Subgroup A.1 General ... 58

Table 4-5: PG&E Subgroup A.1 General Average Event Day Impacts by Geography Domains ... 60

Table 4-6: PG&E Subgroup A.1 General Average Event Day Impacts By Particpant Characteristics ... 61

Table 4-7: PG&E PY 2022 ELRP Average Event Hour Impact – Subgroup A.1 General PDP Participants ... 63

Table 4-8: PG&E PY 2022 ELRP Average Event Hour Impact – Subgroup A.2 BIP – Delivered Load ... 65

Table 4-9: PG&E PY 2022 ELRP Average Event Hour Impact – Subgroup A.2 BIP – Net Load ... 65

Table 4-10: PG&E Subgroup A.2 BIP Average Event Day Impacts By Geography Domains ... 67

Table 4-11: PG&E Subgroup A.2 BIP Average Event Day Impacts by Particpant Characteristics ... 68

Table 4-12: PG&E PY 2022 ELRP Average Event Hour Impact – Subgroup A.4 VPP ... 72

Table 4-13: PG&E Subgroup A.4 VPP Average Event Day Impacts by Geography Domains ... 74

Table 4-14: PG&E Subgroup A.4 VPP Average Event Day Impacts by Participant Characteristics ... 75

Table 4-15: PG&E PY 2022 ELRP Average Event Hour Impact – Subgroup A.6 Residential – Delivered Load ... 77

Table 4-16: PG&E PY 2022 ELRP Average Event Hour Impact – SubGroup A.6 Residential – Net Load ... 77

Table 4-17: PG&E Subgroup A.6 Residential Average Event Day Impacts by Enrollment Group and Load Type ... 79

Table 4-18: PG&E Subgroup A.6 Residential Average Event Day Per Capita Load Impacts Contribution - Flex Alert vs. ELRP ... 80

Table 4-19: PG&E Subgroup A.6 Residential Average Event Day Impacts By Enrollment Group and Load Type – Dually Enrolled SmartRate™ Particpants ... 83

Table 4-20: PG&E PY 2022 ELRP Average Event Hour Impact – Subgroup B.2 CBP Aggregators ... 84

Table 4-21: PG&E Subgroup B.2 CBP Aggregator Average Event Day Impacts By Geography Domains ... 86

Table 4-22: PG&E Subgroup B.2 CBP Aggregator Average Event Day Impacts By Partcipant Characteristics ... 87

Table 4-23: PG&E PY 2022 Aggregate Hourly Load Impacts for The Average Event Day – Group A.1 BIP ... 89

Table 4-24: PG&E PY 2022 Aggregate Hourly Load Impacts for The Average Event Day – Group A.1 General ... 90

Table 4-25: PG&E PY 2022 Aggregate Hourly Load Impacts for The Average Event Day – Group A.2 BIP Net Load ... 91

Table 4-26: PG&E PY 2022 Aggregate Hourly Load Impacts for The Average Event Day – Group A.2 BIP Delivered Load ... 92

Table 4-27: PG&E PY 2022 Aggregate Hourly Load Impacts for The Average Event Day – Group A.4 VPP ... 93

Table 4-28: PG&E PY 2022 Aggregate Hourly Load Impacts for The Average Event Day – Group A.6 Residential Net Load ... 94

Table 4-29: PG&E PY 2022 Aggregate Hourly Load Impacts for The Average Event Day – Group A.6 Residential Delivered Load ... 95

Table 4-30: PG&E PY 2022 Aggregate Hourly Load Impacts for The Average Event Day – Group B.2 CBP Aggregator ... 96

Table 4-31 PG&E Group A.1 Nomination Realization Rates By Event ... 98

Table 5-1: PY 2023 Portfolio and Program Utility 1-in-2 Ex Ante Impacts – Subgroup A.1 BIP ... 100

Table 5-2: PY 2023 Portfolio and Program Utility 1-in-2 Typical Event Day Ex Ante Impacts – Subgroup A.1 General ... 102

Table 5-3: PY 2023 Portfolio and Program Utility 1-in-2 Typical Event Day Ex Ante Impacts – Subgroup A.1 General - PDP Dually Enrolled ... 103

Table 5-4: PY 2023 Portfolio and Program Utility 1-in-2 Ex Ante Impacts – Subgroup A.2 BIP – Delivered Load ... 105

Table 5-5: PY 2023 Portfolio and Program Utility 1-in-2 Typical Event Day Ex Ante Impacts – Subgroup A.4 VPP ... 106

Table 5-6: PY 2023 Portfolio and Program Utility 1-in-2 Typical Event Day Ex Ante Impacts – Subgroup A.6 Residential ... 108

Table 5-7: PY 2023 Portfolio and Program Utility 1-in-2 Typical Event Day and August System Peak Ex Ante Impacts – Subgroup A.6 Residential By Enrollment Group ... 110

Table 5-8: PY 2023 Portfolio and Program Utility 1-in-2 Typical Event Day Ex Ante Impacts – Subgroup B.2 CBP Aggregator ... 112

Table 5-9: Utility 1-in-10 Typical Event Day Ex Ante Aggregate Impacts by Program year and ELRP Subgroup – Portfolio Adjusted ... 113

Table 5-10: Utility 1-in-2 Typical Event Day Ex Ante Aggregate Impacts by Program year and ELRP Subgroup – Portfolio Adjusted ... 113

Table 6-1: Comparison of PY 2021 and PY 2022 Ex Post Impacts ... 115

Table 6-2: Comparison of PY 2021 Ex Ante Impacts for 2022 and PY 2022 Average Event Day Ex Post Impacts ... 116

Table 6-3: Comparison of PY 2021 Ex Ante Impacts and PY 2022 Ex Ante Estimates for PY 2023 ... 117

Table 6-4: Comparison of PY 2022 Ex Ante Utility Typical Event Day Impacts and PY 2022 Ex Post Impacts ... 118

Table B-1: Descriptions and Equations for Performance Metrics ... 123

Table B-2: Specification Test Results for Proxy Day Testing - PG&E Subgroup A.1 BIP ... 124

Table B-3: Specification Test Results for Proxy Day Testing - PG&E Subgroup A.1 General ... 124

Table B-4: Specification Test Results for Proxy Day Testing - PG&E Subgroup A.2 BIP ... 124

Table B-5: Specification Test Results for Proxy Day Testing - PG&E Subgroup A.4 VPP By Segment 125

Table B-6: Specification Test Results for Proxy Day Testing - PG&E Subgroup A.4 VPP By Segment 125

Table B-7: Specification Test Results for Proxy Day Testing - PG&E Subgroup B.2 CBP Aggregator By Segment 125

VERDANT

Public Version. Confidential content removed and blacked out.

1 EXECUTIVE SUMMARY

The Emergency Load Reduction Program (ELRP) is a Pacific Gas and Electric Company (PG&E) demand response (DR) pilot,[1] authorized by the California Public Utilities Commission (CPUC) for five years, that allows the Investor-Owned Utilities (IOUs) and the California Independent System Operator (CAISO) to access additional, emergency load reduction during times of high grid stress. The goal of the program is to help the IOUs and CAISO avoid outages while controlling costs to ratepayers. Program participants receive payments for the energy reduction provided over the event period with no capacity payments.

The ELRP is available from May to October, seven days a week from 4:00 P.M. to 9:00 P.M. with a one-hour minimum and a five-hour maximum event duration.[2] Participants can be dispatched using a Day Ahead or Day Of notification for a maximum of 60 hours with no restrictions on consecutive day dispatches.[3] Eligible customers are broken into two distinct groups with multiple sub-groups.[4]

Group A participant groups include:

- A.1 - Non-residential customers and individual Base Interruptible Program (BIP) participants
- A.2 - Non-residential aggregators
- A.3 - Rule 21 exporting distributed energy resources
- A.4 - Virtual power plant aggregators
- A.5 – Electric Vehicle (EV) and Vehicle-to-Grid Integration (VGI) aggregators
- A.6 - Residential customers

Group B participant groups include:

- B.1 - Third-party Demand Response Providers (DRPs)
- B.2 - Capacity Bidding Program (CBP) Aggregators

1 SDG&E also administers ELRP. SCE also administers ELRP, but their evaluation findings are covered in separate evaluation report.

2 Subgroup A.6 events are always 5 hours in duration, lasting from 4:00 pm to 9:00 pm.

3 Subgroup A.6 events are always dispatched Day Ahead. There is no Day Of event trigger for this subgroup.

4 Definitions of groups are taken from the ELRP FAQ page. https://elrp.olivineinc.com/customer-faq/

In program year (PY) 2022, the ELRP saw event participation in all groups except Groups A.3 and A.5. Group B.1 participants will not be included in this evaluation to protect aggregator and customer confidentiality.

The objective of this evaluation is to assess the PY 2022 ELRP in a manner that conforms to the Load Impact Protocols (LIP) adopted by the CPUC in Decision (D.) 08-04-050. At a high level, there are two main objectives related to the impact evaluation of the ELRP. These include:

- **Ex Post Analysis:** The goal of the ex post analysis is to estimate incremental load impacts for PY 2022 ELRP events and for an average event day that conforms to the LIP.
- **Ex Ante Analysis**: The goal of the ex ante analysis is to forecast incremental load reductions through the life of the ELRP pilot (PY 2023 through PY 2025) under 1-in-2 and 1-in-10 weather scenarios in a manner that conforms to the LIP.

1.1 PARTICIPANT CHARACTERISTICS

PG&E had 1,581,411 customers that participated in PY 2022 events in Group A and 13 aggregators in Group B of the ELRP. Table 1-1 below provides customer counts by ELRP subgroup. The majority of participants were enrolled through subgroup A.6 (residential customers). This is the result of auto-enrolling all California Alternate Rates for Energy Program (CARE), Family Electric Rate Assistance Program (FERA), and home energy report (HER) residential customers. Subgroup A.1 is the second largest ELRP subgroup with 7,184 customers, nine of which were individually enrolled BIP customers. Subgroup A.4, Virtual Power Plant (VPP) aggregators, had a total of 3,758 participants, all under one aggregator.

TABLE 1-1: ACTIVE PY2022 ELRP CUSTOMER ENROLLMENT COUNTS

ELRP Group	ELRP Subgroup	Customer Counts*
Group A	A.1 - Non-residential – General	7,175
	A.1 - Non-residential – BIP	9
	A.2 - Non-residential aggregators – BIP	112
	A.2 - Non-residential aggregators – Non-BIP	0
	A.3 - Rule 21 exporting distributed energy resources	0
	A.4 - Virtual power plant aggregators	3,758
	A.5 - EV and VGI aggregators	0
	A.6 - Residential customers	1,570,357
	Total Group A	**1,581,411**
Group B	B.1 - Third-party Demand Response Providers (DRPs)	NA
	B.2 - Capacity Bidding Program Aggregators	580
	Total Group B	**580†**

*Customer counts only include ELRP participants that participated in at least one event during PY2022.

† Customer counts for Group B exclude B.1 (third party DRPs) from customer counts.

1.2 EVENT INFORMATION

There were eleven ELRP events days during the 2022 event season in PG&E's service territory. All events, with one exception, were Day Ahead events. This contrasts with the 2021 event season which only included Day Of events. Table 1-2 below presents the PY 2022 ELRP event days, event times, event duration, subgroups dispatched, and event types. There was no enrollment in subgroups A.3 and A.5 during the PY 2022 events.

TABLE 1-2: PY 2022 PG&E ELRP EVENT INFORMATION

Event Date	Event Time	Duration (Hours)	Subgroup(s)*	Event Type
8/17/2022	16:00-21:00	5	A.2 non-BIP, A.4, A.6	Day Ahead
8/31/2022	17:00-20:00	3	All non-A.6	Day Of
9/1/2022	18:00-19:00	1	All non-A.6	Day Ahead
	16:00-21:00	5	A.6	Day Ahead
9/2/2022	16:00-21:00	5	A.6	Day Ahead
9/3/2022	18:00-20:00	2	All non-A.6	Day Ahead
	16:00-21:00	5	A.6	Day Ahead
9/4/2022	17:00-20:00	3	All non-A.6	Day Ahead
	16:00-21:00	5	A.6	Day Ahead
9/5/2022	17:00-21:00	4	All non-A.6	Day Ahead
	16:00-21:00	5	A.6	Day Ahead
9/6/2022	16:00-21:00	5	All non-A.6	Day Ahead (extended Day Of)
	16:00-21:00	5	A.6	Day Ahead
9/7/2022	16:00-21:00	5	All Subgroups	Day Ahead
9/8/2022	16:00-21:00	5	All Subgroups	Day Ahead
9/9/2022	16:00-18:00	2	All non-A.6	Day Ahead (extended Day Of, ended early Day Of)
	16:00-21:00	5	A.6	Day Ahead

*Subgroups A.3 and A.5 participants did not have any enrolled participants during events in PY 2022.

1.3 METHODOLOGY

1.3.1 Ex Post Methodology

The ELRP contains multiple subgroups with unique participant characteristics that necessitate different modeling approaches. As a result, the modeling approach for each subgroup varies, but all fall into three categories of modeling approaches. These include individual customer models, panel models with participant fixed effects, and panel modeling with matched control groups. At a high level, the methodologies for relevant subgroups are as follows.

Subgroups A.1, A.2, and B.2

Subgroup A.1, A.2 and B.2 all represent non-residential customers that are comprised of a wide variety of industry and load types. As a result, Verdant utilized customer specific regression models for estimation of ex post impacts. This approach allows for varying baselines for each customer, specific to their characteristics and load variability.

Subgroup A.4 VPP

Subgroup A.4 represents ELRP participation through VPPs. For PG&E, all A.4 VPP participants were residential customers. Given the relative homogeneity of residential loads, Verdant utilized panel modeling with participant fixed effects for estimating impacts. Participants were segmented into modeling groups based on LCA, SubLAP, climate zone, customer type, and dual enrollment status. Additional secondary segmentation was used to model the remaining domains of interest, including NEM status and technology types. For segments without sufficient participant counts for panel modeling, customer specific regression models were used in place of panel models.

Subgroup A.6 Residential

Subgroup A.6 represents the residential component of ELRP that was introduced in PY 2022. Enrollment for this group was automatic for PG&E customers in CARE, FERA, and HER programs, though there is also a small set of self-enrolled customers. There are two aspects to this subgroup that set it apart from the others. The first is the sheer quantity of participants, which calls for a method that samples customers to assess the impacts. The second is the automatic enrollment for most participants, which makes the use of a control group critical. As a result, panel modeling with non-participant matched control groups was used to estimated load impacts. Additionally, a sample of participants was selected for modeling purposes given the more than 1.5 million customers enrolled in the subgroup A.6 Residential.

1.3.2 Ex Ante Methodology

The goal of the ex ante impact analysis is to estimate program impacts for future years under varying 1-in-10 and 1-in-2 weather scenarios across the ELRP event window (4:00 pm to 9:00 pm).[5] Given that the ELRP is a pilot program, the ex ante analysis seeks to provide ex ante estimates for program years 2023 through 2025. The ex ante analysis only seeks to estimate impacts for subgroups that actively participated in events in PY 2022. The primary reason is that there was no event participation for Groups A.3 and A.5 for PG&E. As a result, there are no ex post impacts to inform a LIP-based ex ante analysis.

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

Ex ante impacts are estimated in two ways. These include program level ex ante impacts and the portfolio adjusted ex ante impacts. The program level ex ante impacts represent forecasted program impacts on ELRP-only event days and only include impacts from the ex post analysis in which there is no other DR participation on that day for dually enrolled participants. Conversely, portfolio adjusted ex ante impacts represent ex ante impacts that are incremental to the entire portfolio of PG&E's DR programs and represent incremental load reduction (ILR) impacts. Compensation structures differ for dually enrolled participants and there is no mechanism or penalty structure that ensures reliable participation in ELRP. As a result, there are cases where the portfolio adjusted impacts are larger than the program level impacts. An example of this scenario is for BIP dually enrolled participants who are only compensated for ILR during overlapping BIP event hours and are not compensated on ELRP-only event days. As result, load impacts are larger on dual program days (portfolio level) than on days in which there is only an ELRP event.

1.4 EX POST IMPACTS

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

Public Version. Confidential content removed and blacked out.

TABLE 1-3: PG&E 2022 ELRP AVERAGE EVENT HOUR IMPACTS BY GROUP

Group	Event Date	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Service Point Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
Group A.1 BIP	8/31/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/1/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/3/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/4/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/5/2022*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/6/2022*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/7/2022*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/8/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/9/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Avg. Event	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Group A.1 General[6]	8/31/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/1/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/3/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/4/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/5/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/6/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/7/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/8/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/9/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Avg. Event	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Group A.2 BIP	8/31/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/1/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/3/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/4/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/5/2022*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/6/2022*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/7/2022*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/8/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/9/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Avg. Event	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Group A.4	8/17/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	8/31/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/1/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/3/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/4/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/5/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/6/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/7/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	9/8/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[6] A.1 General is marked confidential due to one participant making up more than 15% of event day loads.

Public Version. Confidential content removed and blacked out.

Group	Event Date	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Service Point Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
	9/9/2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Avg. Event						
Group A.6	8/17/2022	1,480,622	1.709	0.094	5.5%	139.2	85.0
	9/1/2022	1,486,648	1.702	-0.022	-1.3%	-32.9	87.8
	9/2/2022	1,486,940	1.708	0.035	2.0%	51.6	86.2
	9/3/2022	1,487,016	1.674	0.047	2.8%	69.5	87.3
	9/4/2022	1,487,135	1.876	0.052	2.8%	76.9	93.6
	9/5/2022	1,487,934	2.161	0.037	1.7%	54.6	98.0
	9/6/2022	1,509,296	2.213	0.057	2.6%	86.7	97.7
	9/7/2022	1,509,335	2.039	0.040	1.9%	59.6	93.7
	9/8/2022	1,509,436	2.039	-0.007	-0.4%	-11.1	95.1
	9/9/2022	1,509,460	1.821	0.030	1.6%	45.1	88.2
	Avg. Event	1,495,382	1.895	0.036	1.9%	53.9	91.3
Group B.2 CBP	8/31/2022*	514	200.9	6.7	3.4%	3.5	84.6
	9/1/2022*	578	181.2	36.0	19.9%	20.8	89.5
	9/3/2022	578	188.3	-2.6	-1.4%	-1.5	87.3
	9/4/2022*	578	178.8	5.7	3.2%	3.3	94.7
	9/5/2022	578	191.7	-3.4	-1.8%	-2.0	96.5
	9/6/2022*	578	156.0	-3.7	-2.4%	-2.2	97.2
	9/7/2022*	578	166.0	6.5	3.9%	3.8	93.8
	9/8/2022*	578	165.5	1.9	1.2%	1.1	94.9
	9/9/2022	578	207.1	6.9	3.4%	4.0	92.6
	Avg. Event	567	175.7	2.0	1.1%	1.1	93.7

On the average event day, PG&E A.1 general participants provided an average of [redacted] MW of load reduction in each ELRP event hour. The largest load reduction, on average, occurred on September 9th, with an average hourly load reduction of [redacted] MW (or 5.3% of the estimated baseline).

PG&E Group A.1 BIP participants average event day load reduction was [redacted] MW in each ELRP event hour. Their largest load reduction, on average, occurred on September 8th, with an average hourly load reduction of [redacted] MW or 28.5 percent of estimated baseline reference load. Group A.1 BIP ELRP participants were only compensated for incremental load reduction on dual BIP ELRP event days. BIP aggregators, however, voluntarily participated on non-BIP days as their largest average load reduction occurred on a non-BIP day.

Dual BIP and ELRP Group A.2 participants provided an average of [redacted] MW of load reduction in each ELRP event hour. Their largest load reduction, on average, occurred on September 6th, with an average hourly load reduction of [redacted] MW or 19.7% of estimated baseline reference load. Similar to Group A.1 BIP, Group

A.2 BIP participants were only compensated for incremental load reduction on dual BIP ELRP event days. Group A.2 BIP aggregators showed limited load reduction on non-BIP days.

ELRP Group B.2 participants are dually enrolled in CBP and ELRP. These customers provided an average of 1.1 MW of load reduction in each ELRP event hour. Their largest load reduction, on average, occurred on September 1st, with an average hourly load reduction of 20.8 MW or 19.9% of estimated baseline reference load. Similar to Group A.1 BIP and Group A.2 BIP, sub-group B.2 participants were only compensated for incremental load reduction on dual CBP ELRP event days. Group B.2 CBP showed no or very limited load reduction on non-CBP days.

PG&E Group A.4 participants are residential customers participating in ELRP through a VPP. Their average event day load reduction was [redacted] MW in each ELRP event hour. Most of these customers are on a NEM tariff and use a battery or solar PV paired with a battery to participate in ELRP. Their baseline reference net load includes both positive and negative values, therefore the average percent load reduction is not intuitive and is excluded from Table 1-3.

Group A.4's largest load reduction, on average, occurred on September 1st, with an average hourly load reduction of [redacted] MW and their second highest average hourly load reduction occurring on September 3rd ([redacted] MW). For Group A.4 participants, the full level of load curtailment last for only a maximum of two hours and then severely dissipate in the third hour. The Group A.4 September 1st and 3rd event duration were only one and two hours respectively. During longer duration events, the participants' batteries are often charging during the early and/or late event hours, reducing the average hourly load reduction during those events.

On the average event day, nearly 1.5 million customers participated in PG&E's A.6 ELRP program, providing an average of 53.9 MW of load reduction in each ELRP event hour. The largest load reduction, on average, occurred on September 6th, with an average hourly load reduction of 86.7 MW or 2.6% of the estimated baseline reference load.

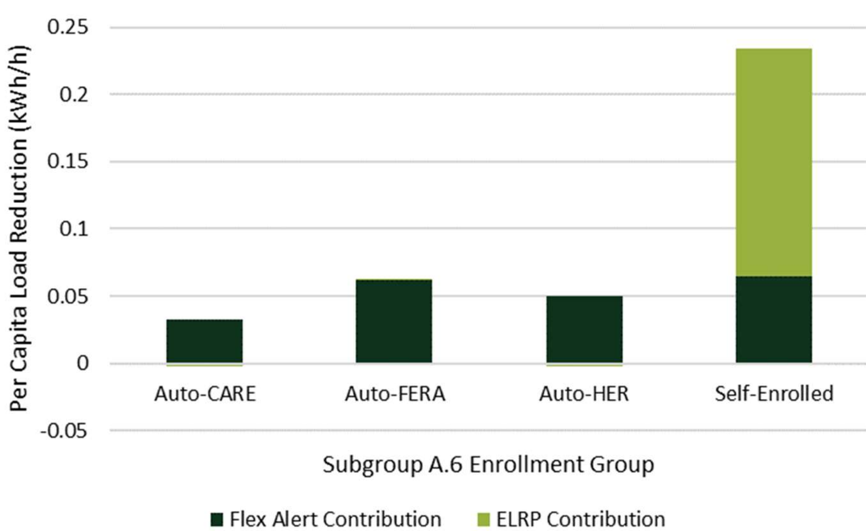
There are four enrollment pathways into the A.6 Residential subgroup. These include CARE auto-enrollment, FERA auto-enrollment, HER auto-enrollment and self-enrollment. While Table 1-3 presents the aggregate A.6 load impacts, load impacts were also developed for each sub-group. The average event day load reduction is largest for the auto-enrolled CARE subgroup at 31.6 MW but the largest average per capita impact is from the self-enrolled sub-group at 0.233 kW or 10.4% of their baseline reference load. Participants that self-enrolled in ELRP have a substantially larger average percent load reduction than customers who were auto-enrolled.

TABLE 1-4: PG&E GROUP A.6 ELRP AVERAGE EVENT DAY IMPACTS BY ENROLLMENT TYPE

Enrollment Group	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
Auto-Enrollment: CARE	1,053,744	1.872	0.030	1.6%	31.6	92.2
Auto-Enrollment: FERA	29,790	2.346	0.062	2.6%	1.8	91.6
Auto-Enrollment: HER	408,355	1.918	0.048	2.5%	19.7	88.7
Self-Enrollment	3,494	2.239	0.233	10.4%	0.8	99.9
All A.6	**1,495,382**	**1.895**	**0.036**	**1.9%**	**53.9**	**91.3**

All A.6 ELRP events were five hours in duration and each event was also a population level Flex Alert. For purposes of reporting impacts, the reported total load reduction results in Table 1-3 and Table 1-4 are the combined ELRP and Flex Alert impacts. The ex post analysis, however, developed incremental load impact estimates for ELRP and Flex Alerts. Figure 1-1 present the incremental load reductions from ELRP and Flex Alerts relative to reported impacts by enrollment type. ELRP's contribution is virtually zero for the auto-enrolled subgroups but substantial for the self-enrolled subgroup. The incremental load reduction analysis shows auto-enrolled customers' load reduction is similar to the population's Flex Alert load reduction and there is essentially no additional load reduction as a result of auto-enrolling the entire population of CARE, FERA and HER customers into the ELRP.

FIGURE 1-1: PG&E GROUP A.6 AVERAGE EVENT DAY PER CAPITA LOAD IMPACTS CONTRIBUTION - FLEX ALERT VS. ELRP



1.4.1 Average Event Day Load Shapes

Visually representing event day load shapes and estimated baseline is a powerful tool for understanding event day activity and for framing impact estimates. For this reason, this report first presents event day load shapes for each subgroup. Given that events occurred on varying hours across event days, the density of the shaded areas relates to the frequency of event days where a given hour was an event hour. The opaquer the shading on an event hour, the more frequently that hour was an event hour.

Additionally, ELRP impacts represent ILR. As a result, the ex post baseline includes other DR program impacts, which presents visually as a kink in the ELRP baseline. This is most noticeable in the A.1 BIP, A.2 BIP, and B.2 CBP Aggregator load shapes (Figure 1-2, Figure 1-4, and Figure 1-7 respectively).

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

[redacted]

FIGURE 1-3: PG&E AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – SUBGROUP A.1 GENERAL

[redacted]

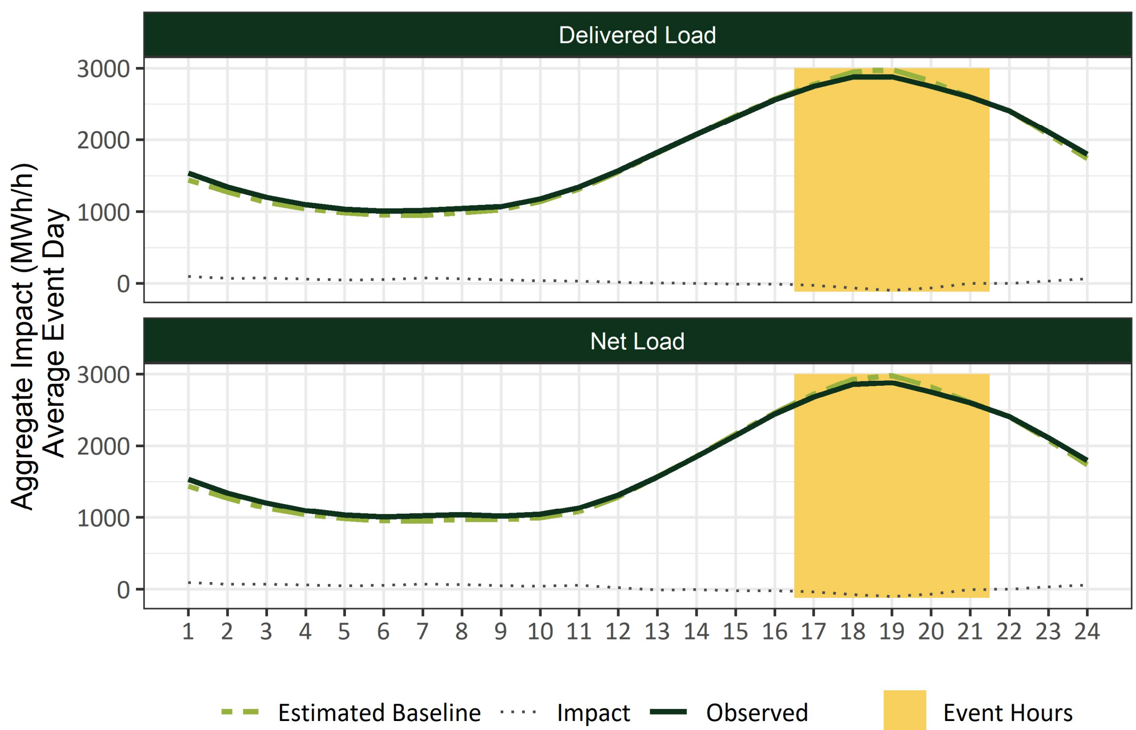
FIGURE 1-4: PG&E AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – SUBGROUP A.2 BIP

[redacted]

FIGURE 1-5: PG&E AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – SUBGROUP A.4 VPP

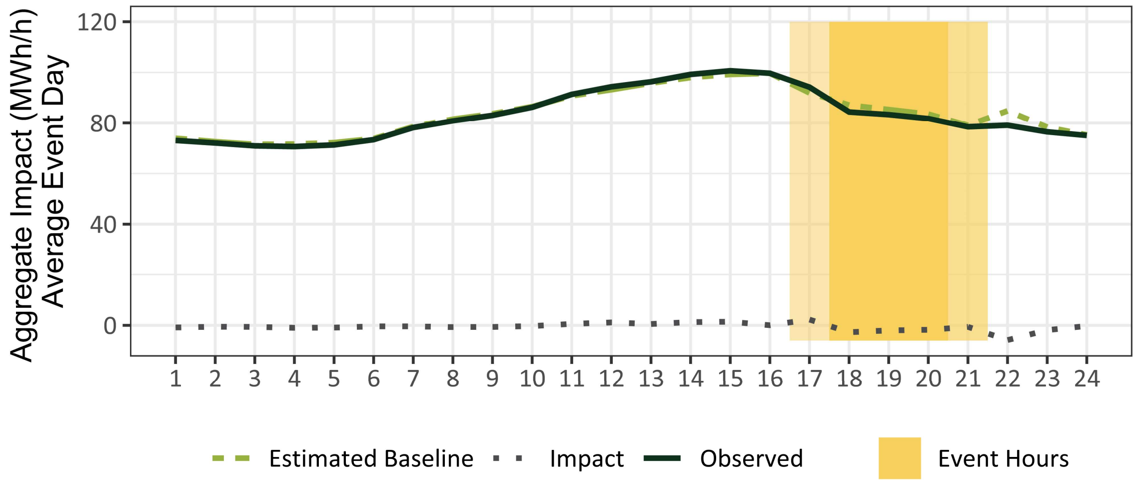
[redacted]

FIGURE 1-6: PG&E AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – SUBGROUP A.6 RESIDENTIAL



Public Version. Confidential content removed and blacked out.

FIGURE 1-7: PG&E AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – SUBGROUP B.2 CBP AGGREGATOR



1.5 EX ANTE IMPACTS

Table 1-5 and Table 1-6 provide the portfolio adjusted utility typical event day aggregate ex ante forecasts under 1-in-10 and 1-in-2 weather scenarios, respectively, by year. As seen the PY 2023 ex ante 1-in-10 forecast is 79.9 MWh across all ELRP program segments covered in this evaluation and 75.4 MWh for 1-in-2 weather conditions.

TABLE 1-5: UTILITY 1-IN-10 TYPICAL EVENT DAY EX ANTE AGGREGATE IMPACTS BY PROGRAM YEAR AND ELRP SUBGROUP – PORTFOLIO ADJUSTED

	Utility 1-in-10 Typical Event Day					
	PY 2023		PY 2024		PY 2025	
ELRP Subgroup	Num. of Parts	MWh Forecast	Num. of Parts	MWh Forecast	Num. of Parts	MWh Forecast
A.1 BIP	10	1.4	10	1.4	10	1.4
A.1 General - All	7,010	19.2	6,986	19.2	6,960	19.2
A.2 BIP*	111	3.6	111	3.6	111	3.6
A.4 VPP	4,292	7.1	4,292	7.1	4,292	7.1
A.6 Residential*	1,735,279	44.8	1,835,280	47.1	1,935,280	49.5
B.2 CBP	601	5.2	601	5.2	601	5.2
ELRP Total	**1,747,293**	**79.9**	**1,847,270**	**82.2**	**1,947,244**	**84.6**

*Indicates estimations based on Delivered Load

Public Version. Confidential content removed and blacked out.

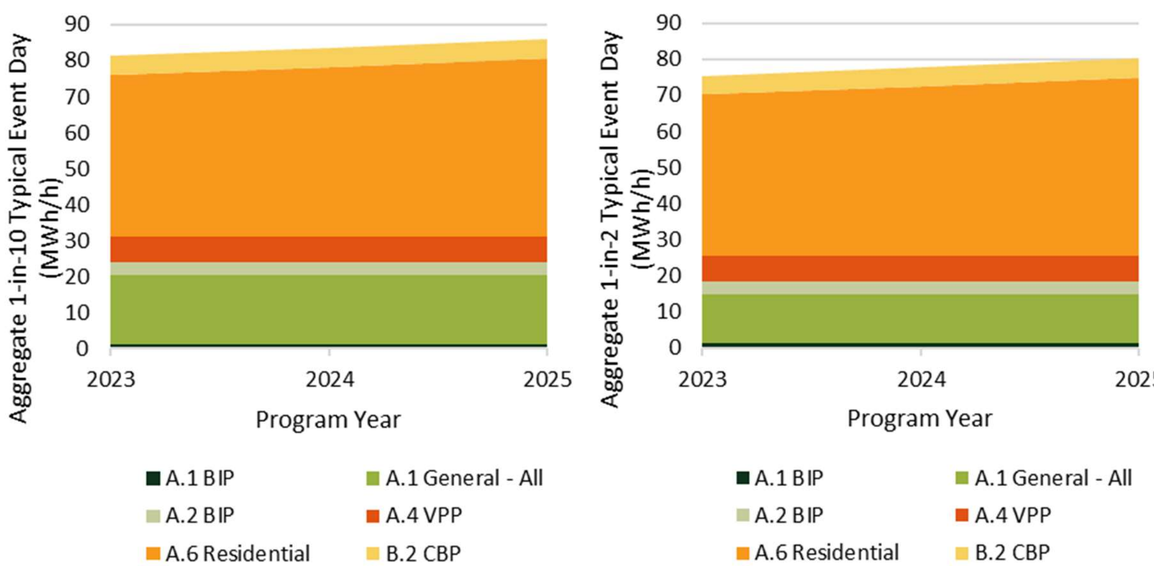
TABLE 1-6: UTILITY 1-IN-2 TYPICAL EVENT DAY EX ANTE AGGREGATE IMPACTS BY PROGRAM YEAR AND ELRP SUBGROUP – PORTFOLIO ADJUSTED

	Utility 1-in-2 Typical Event Day					
	PY 2023		PY 2024		PY 2025	
ELRP Subgroup	**Num. of Parts**	**MWh Forecast**	**Num. of Parts**	**MWh Forecast**	**Num. of Parts**	**MWh Forecast**
A.1 BIP	10	1.4	10	1.4	10	1.4
A.1 General - All	7,010	13.3	6,986	13.3	6,960	13.3
A.2 BIP*	111	3.6	111	3.6	111	3.6
A.4 VPP	4,292	7.1	4,292	7.1	4,292	7.1
A.6 Residential*	1,735,279	44.8	1,835,280	47.1	1,935,280	49.5
B.2 CBP	601	5.2	601	5.2	601	5.2
ELRP Total	**1,747,303**	**75.4**	**1,847,280**	**77.70**	**1,947,254**	**80.1**

*Indicates estimations based on Delivered Load

Figure 1-8 presents the MWh ex ante forecasts by year visually. As seen the largest driver for differences between the 1-in-10 and 1-in-2 weather scenarios is driven by subgroups A.1 General

FIGURE 1-8: PG&E 1-IN-10 (RIGHT) AND 1-IN-2 (LEFT) UTILITY TYPICAL EVENT DAY EX ANTE AGGREGATE IMPACTS BY PROGRAM YEAR AND ELRP SUBGROUP



2 INTRODUCTION

The Emergency Load Reduction Program (ELRP) is a Pacific Gas and Electric Company (PG&E) demand response (DR) pilot,[7] authorized by the California Public Utilities Commission (CPUC) for five years, that allows the Investor-Owned Utilities (IOUs) and the California Independent System Operator (CAISO) to access additional, emergency load reduction during times of high grid stress. The goal of the program is to help the IOUs and CAISO avoid outages while controlling costs to ratepayers. Program participants receive payments for the energy reduction provided over the event period with no capacity payments.

The ELRP is available from May to October, seven days a week from 4:00 P.M. to 9:00 P.M. with a one-hour minimum and a five-hour maximum event duration.[8] Participants can be dispatched using a Day Ahead or Day Of notification for a maximum of 60 hours with no restrictions on consecutive day dispatches.[9] Eligible customers are broken into two distinct groups with multiple sub-groups.[10]

Group A participant groups include:

- A.1 - Non-residential customers and individual Base Interruptible Program (BIP) participants
- A.2 - Non-residential aggregators
- A.3 - Rule 21 exporting distributed energy resources
- A.4 - Virtual power plant aggregators
- A.5 – Electric Vehicle (EV) and Vehicle-to-Grid Integration (VGI) aggregators
- A.6 - Residential customers

Group B participants groups include:

- B.1 - Third-party Demand Response Providers (DRPs)
- B.2 - Capacity Bidding Program (CBP) Aggregators

In program year (PY) 2022, the ELRP saw event participation in all groups except Group A.3 and A.5. Group B.1 participants is not included in this evaluation to protect customer and aggregator confidentiality.

---

[7] SDG&E and SCE also administer the ELRP in their respective service territories, but they are not included in this report.

[8] Subgroup A.6 events are always 5 hours in duration, lasting from 4:00 pm to 9:00 pm.

[9] Subgroup A.6 events are always dispatched Day Ahead. There is no Day Of event trigger for this subgroup.

[10] Definitions of groups are taken from the ELRP FAQ page. https://elrp.olivineinc.com/customer-faq/

2.1 EVALUATION OBJECTIVES

The objective of this evaluation is to assess the PY 2022 ELRP in a manner that conforms to the Load Impact Protocols (LIP) adopted by the CPUC in Decision (D.) 08-04-050. At a high level, there are two main objectives related to the impact evaluation of the ELRP. These include:

- **Ex Post Analysis:** The goal of the ex post analysis is to estimate incremental load impacts for PY 2022 ELRP events and for an average event day that conforms to the LIP.
- **Ex Ante Analysis**: The goal of the ex ante analysis is to forecast incremental load reductions through the life of the ELRP pilot (PY 2023 through PY 2025) under 1-in-2 and 1-in-10 weather scenarios in a manner that conforms to the LIP.

2.2 PARTICIPANT CHARACTERISTICS

PG&E had 1,581,411 customers that participated in PY 2022 events in Group A and 13 aggregators in Group B of the ELRP. Table 2-1 below provides customer counts by ELRP subgroup. The majority of participants were enrolled through subgroup A.6 (residential customers). This is the result of auto-enrolling all California Alternate Rates for Energy Program (CARE), Family Electric Rate Assistance Program (FERA), and home energy report (HER) residential customers. Subgroup A.1 is the second largest ELRP subgroup with 7,184 customers, nine of which were individually enrolled BIP customers. Subgroup A.4, Virtual Power Plant (VPP) aggregators, had a total of 3,758 participants, all under one aggregator.

TABLE 2-1: ACTIVE PY2022 ELRP CUSTOMER ENROLLMENT COUNTS

ELRP Group	ELRP Subgroup	Customer Counts*
Group A	A.1 - Non-residential – General	7,175
	A.1 - Non-residential – BIP	9
	A.2 - Non-residential aggregators – BIP	112
	A.2 - Non-residential aggregators – Non-BIP	0
	A.3 - Rule 21 exporting distributed energy resources	0
	A.4 - Virtual power plant aggregators	3,758
	A.5 - EV and VGI aggregators	0
	A.6 - Residential customers	1,570,357
	Total Group A	**1,581,411**
Group B	B.1 - Third-party Demand Response Providers (DRPs)	NA
	B.2 - Capacity Bidding Program Aggregators	580
	Total Group B	**580†**

*Customer counts only include ELRP participants that participated in at least one event during PY2022.

† Customer counts for Group B exclude B.1 (third party DRPs) from customer counts.

One of the key features of the ELRP is dual enrollment, the enrollment in the ELRP and another DR program. Table 2-2 below provides the counts of dually enroll ELRP participants by sub-group and program of dual enrollment. While not all ELRP participants are dually enrolled, dual event participation is taken into account for purposes of estimating ex post impacts and generating ex ante forecasts so that impacts represent incremental load reductions (ILR). Details of the estimation of ILR are provided in section 3.2.

TABLE 2-2: ELRP DUAL ENROLLMENT BY SUBGROUP AND PROGRAM

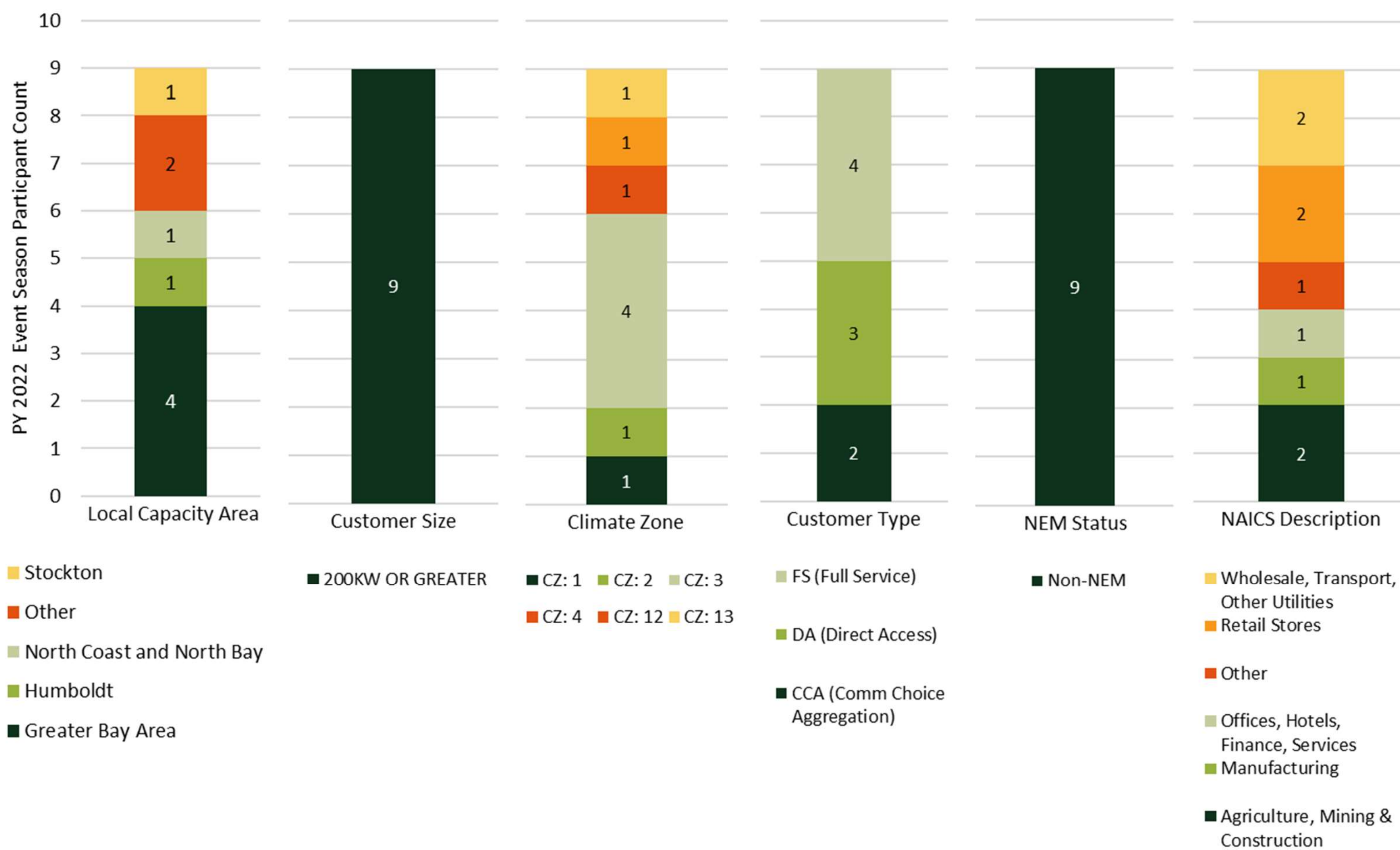
ELRP Subgroup	BIP Enrolled	PDP Enrolled	CBP Enrolled	SmartRate™ Enrolled	SmartAC Enrolled	ELRP Only
A.1 BIP	9	-	-	-	-	-
A.1 General	-	695	15	-	-	6,211
A.2 BIP	112	-	-	-	-	-
A.4 VPP	-	-	-	2	5	3,751
A.6 Residential*	-	-	-	22,393	938	-
B.2 CBP Aggregators	-	-	580	-	-	-

*Values are based on the average of the event days

In general, ELRP participants make up a wide range of customer types, sizes and geographies. Figure 2-1 through Figure 2-6 present the counts and relative shares of participant characteristics for subgroups A.1 BIP, A.1 General, B.2 BIP, A.4 VPP, A.6 Residential and B.2 CBP Aggregators respectively. The presented participant characteristics include Local Capacity Areas (LCA), customer size, climate zones, Customer types, Net Energy Metering (NEM) Status, and NAICS Descriptions. For A.6 Residential, enrollment reason and disadvantaged community (DAC) status are presented in place of customer size and NAICS description.

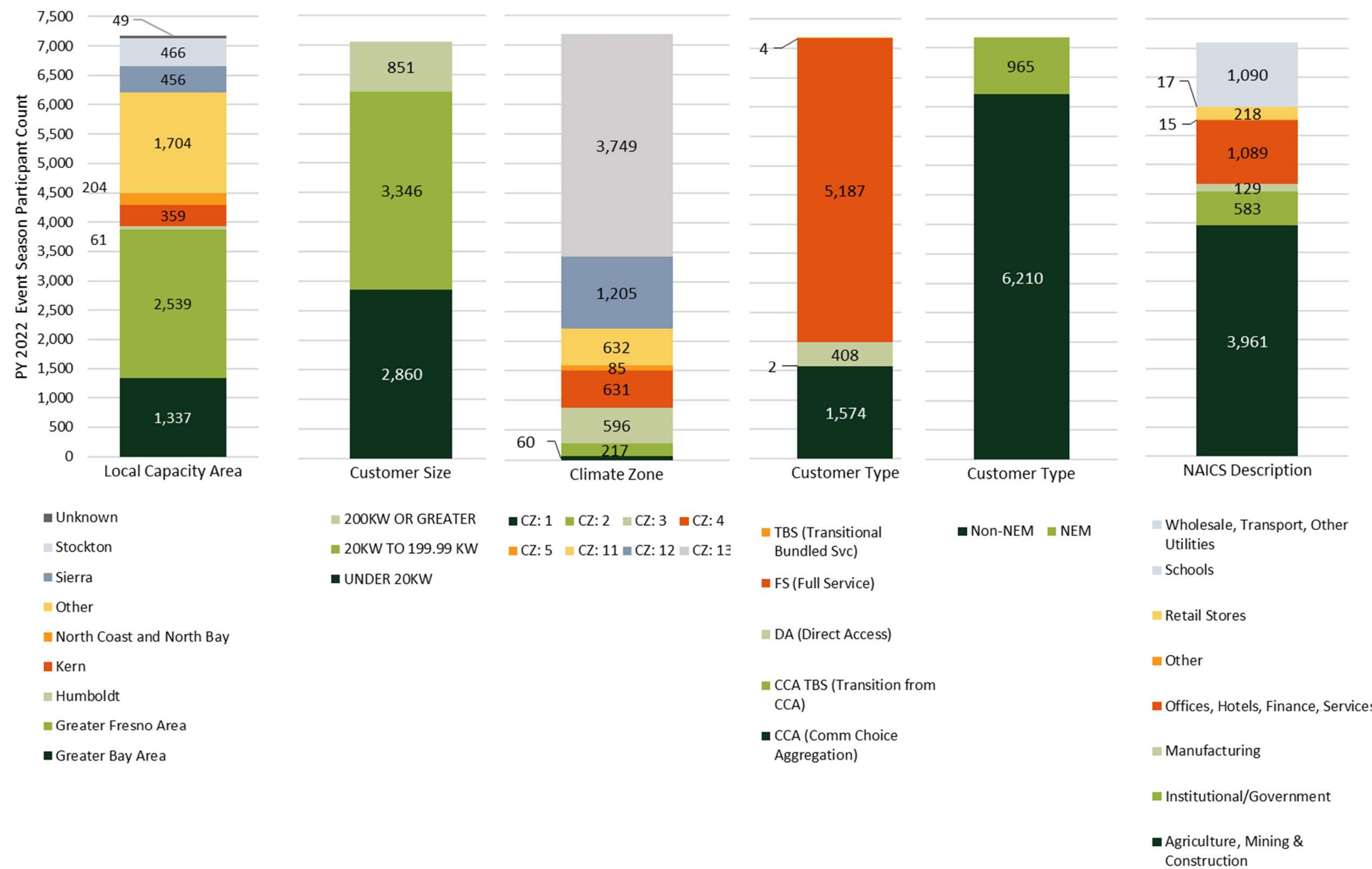
Public Version. Confidential content removed and blacked out.

FIGURE 2-1: A.1 BIP PARTICIPANT COUNTS BY POPULATION CHARACTERISTIC TYPE



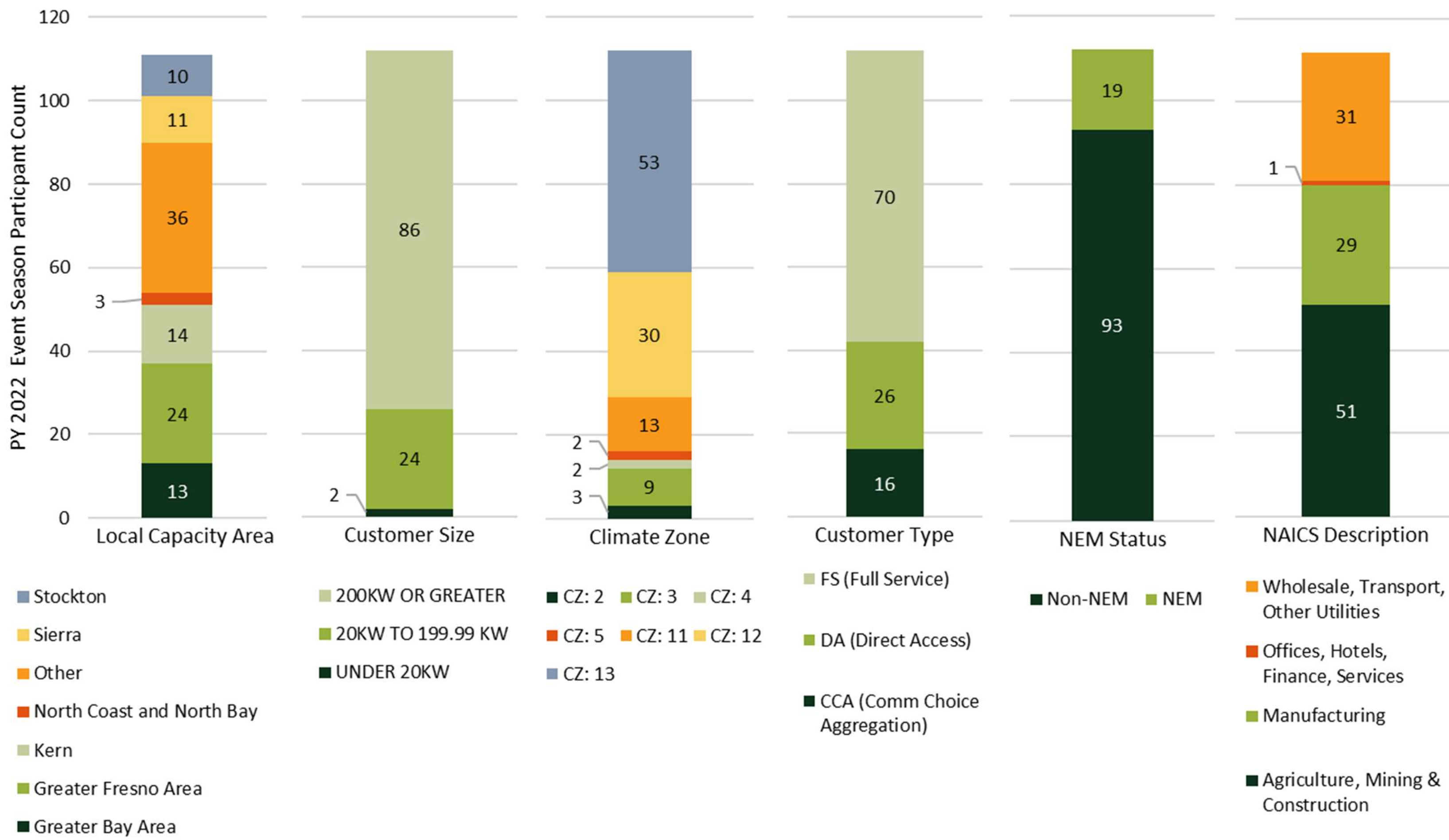
Public Version. *Confidential content removed and blacked out.*

FIGURE 2-2: A.1 GENERAL PARTICIPANT COUNTS BY POPULATION CHARACTERISTIC TYPE



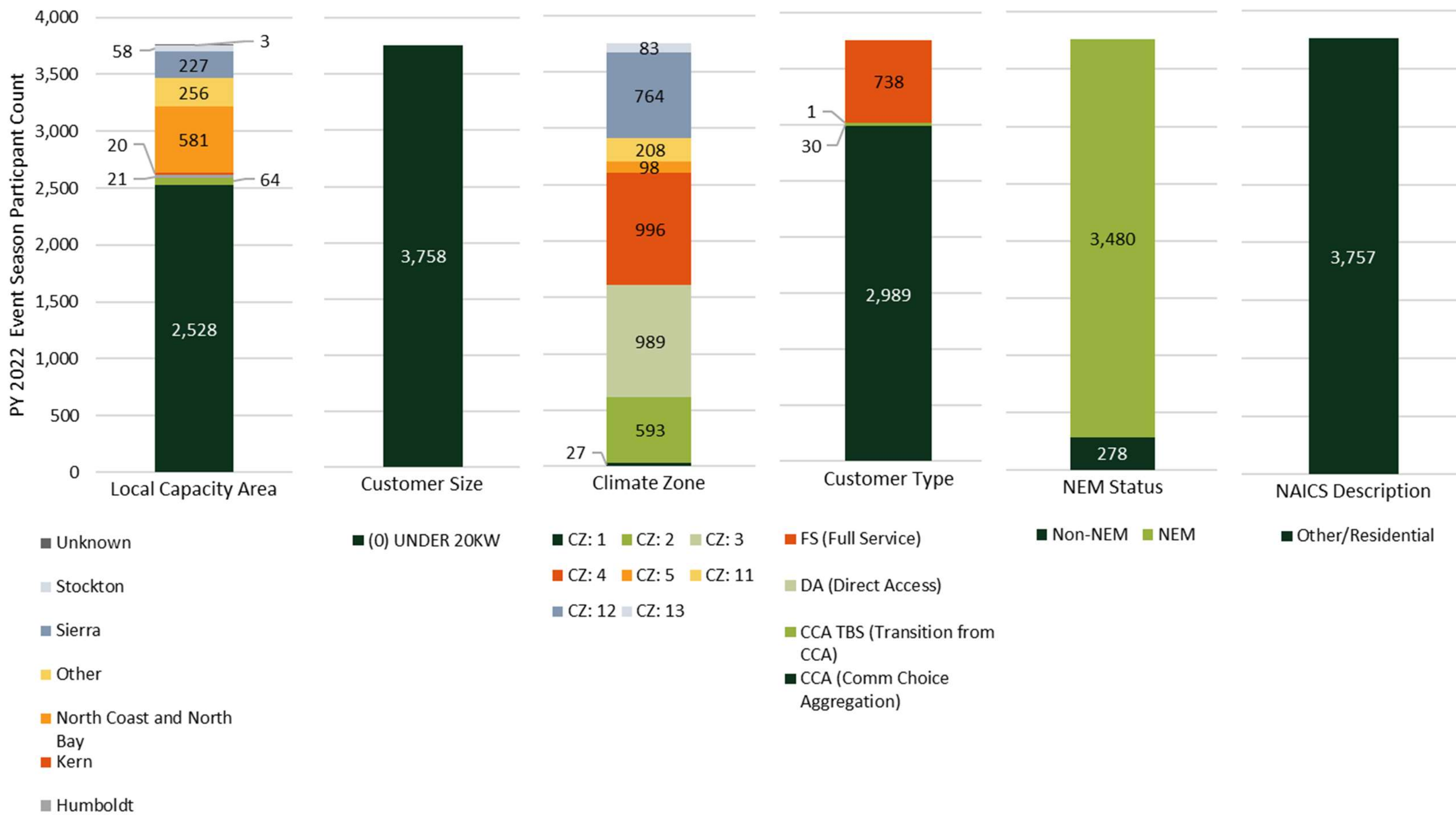
Public Version. Confidential content removed and blacked out.

FIGURE 2-3: A.2 BIP PARTICIPANT COUNTS BY POPULATION CHARACTERISTIC TYPE



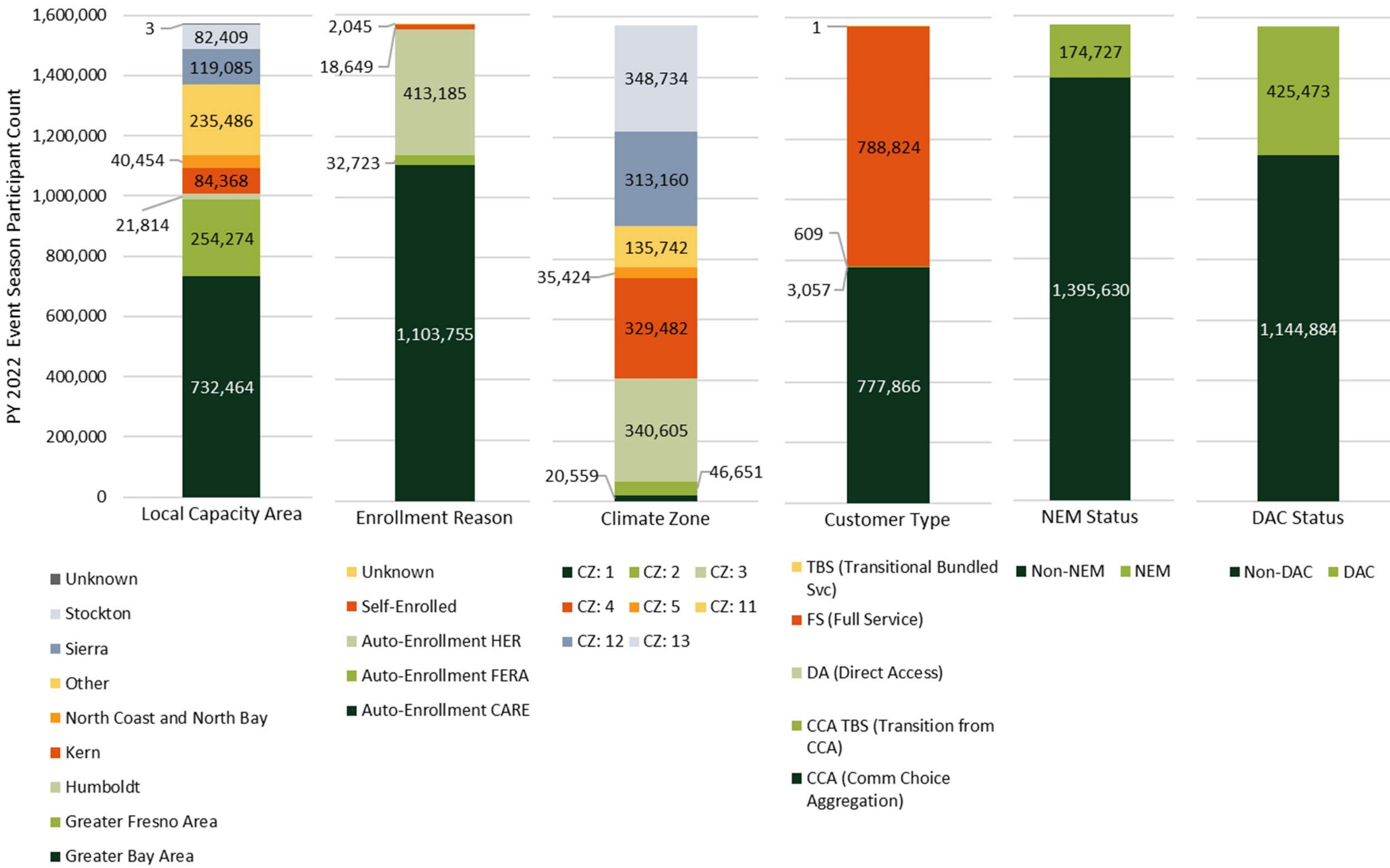
Public Version. Confidential content removed and blacked out.

FIGURE 2-4: A.4 VPP PARTICIPANT COUNTS BY POPULATION CHARACTERISTIC TYPE



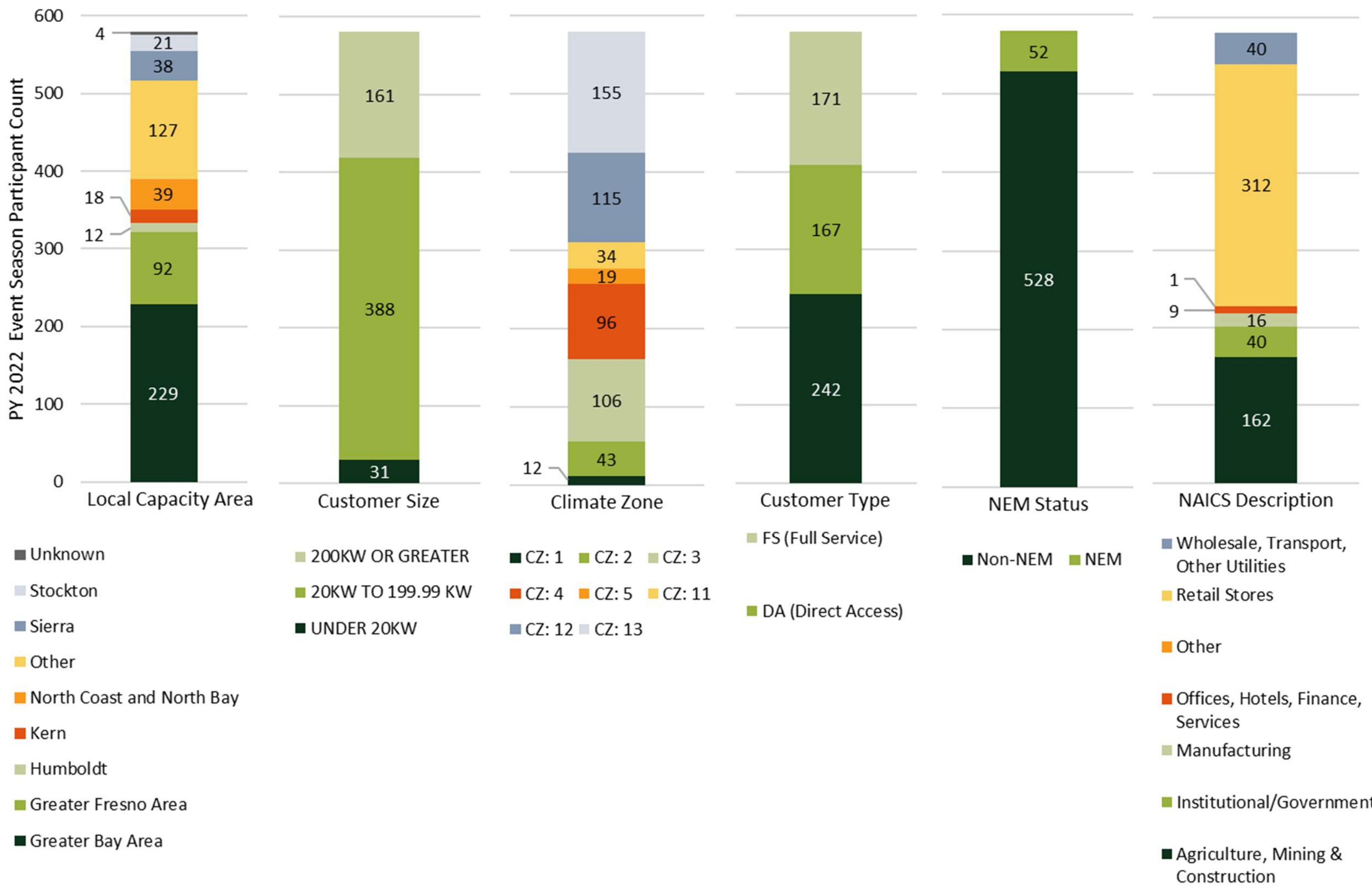
Public Version. Confidential content removed and blacked out.

FIGURE 2-5: A.6 RESIDENTIAL PARTICIPANT COUNTS BY POPULATION CHARACTERISTIC TYPE



Public Version. Confidential content removed and blacked out.

FIGURE 2-6: B.2 CBP AGGREGATOR PARTICIANT COUNTS BY POPULATION CHARACTERISTIC TYPE



2.3 EVENT INFORMATION

There were eleven ELRP events days during the 2022 event season in PG&E's service territory. All events, with one exception, were Day Ahead events. This contrasts with the 2021 event season which only included Day Of events. Table 2-3 below presents the PY 2022 ELRP event days, event times, event duration, subgroups dispatched, and event types. There was no enrollment in subgroups A.3 and A.5 during PY 2022 events.

TABLE 2-3: PY 2022 PG&E ELRP EVENT INFORMATION

Event Date	Event Time	Duration (Hours)	Subgroup(s)*	Event Type
8/17/2022	16:00-21:00	5	A.2 non-BIP, A.4, A.6	Day Ahead
8/31/2022	17:00-20:00	3	All non-A.6	Day Of
9/1/2022	18:00-19:00	1	All non-A.6	Day Ahead
	16:00-21:00	5	A.6	Day Ahead
9/2/2022	16:00-21:00	5	A.6	Day Ahead
9/3/2022	18:00-20:00	2	All non-A.6	Day Ahead
	16:00-21:00	5	A.6	Day Ahead
9/4/2022	17:00-20:00	3	All non-A.6	Day Ahead
	16:00-21:00	5	A.6	Day Ahead
9/5/2022	17:00-21:00	4	All non-A.6	Day Ahead
	16:00-21:00	5	A.6	Day Ahead
9/6/2022	16:00-21:00	5	All non-A.6	Day Ahead (extended Day Of)
	16:00-21:00	5	A.6	Day Ahead
9/7/2022	16:00-21:00	5	All non-A.6	Day Ahead
	16:00-21:00	5	A.6	Day Ahead
9/8/2022	16:00-21:00	5	All non-A.6	Day Ahead
	16:00-21:00	5	A.6	Day Ahead
9/9/2022	16:00-18:00	2	All non-A.6	Day Ahead (extended Day Of, ended early Day Of)

*Subgroups A.3 and A.5 participants did not have any enrolled participants during events in PY 2022.

ELRP event days were dual program days for many ELRP participants that were enrolled in DR programs outside of the ELRP. Additionally, all ELRP event days are Flex Alert days (as Flex Alerts are one of the triggers for an ELRP event). Table 2-4 below presents the event times and dates for programs that overlap with ELRP event days.

TABLE 2-4: PY 2022 PG&E DUAL PROGRAM EVENT DAYS FOR DUALLY ENROLLED ELRP PARTICPANTS

Non-ELRP Program	Event Date	Event Time	Event Type	Load Zone
BIP	9/5/2022	19:15-21:18	Day Of	System
	9/6/2022	18:00-20:38	Day Of	System
	9/7/2022	19:15-20:02	Day Of	System
CBP	9/1/2022	17:00-21:00	Day Ahead	System
	9/2/2022	17:00-20:00	Day Ahead	SubLAPs PGSI, PGCC, PGEB, PGFG, PGNB, PGP2, PGSB, PGSF, PGST
	9/4/2022	18:00-19:00	Day Ahead	SubLAP PGSI
	9/6/2022	16:00-21:00	Day Ahead	System
	9/7/2022	17:00-21:00	Day Ahead	System
	9/8/2022	16:00-21:00	Day Ahead	System
PDP	8/17/2022	16:00-21:00	Day Ahead	System
	9/1/2022	16:00-21:00	Day Ahead	System
	9/5/2022	16:00-21:00	Day Ahead	System
	9/6/2022	16:00-21:00	Day Ahead	System
	9/7/2022	16:00-21:00	Day Ahead	System
SmartAC	8/17/2022	16:30-19:00	Day Ahead	SubLAPs PGNP, PGSI, PGST, PGKN, PGF1, PGZP, PGNC, PGFG, PGNB, PGEB, PGSB, PGP2, PGCC
	9/2/2022	17:00-19:00	Day Ahead	SubLAPs PGF1, PGKN, PGZP
	9/5/2022	18:00-20:00	Day Ahead	System
		20:00-21:18	Day Of	System
	9/6/2022	17:00-20:00	Day Ahead	System
		20:00-20:38	Day Of	System
	9/7/2022	16:00-20:00	Day Ahead	System
	9/8/2022	17:00-20:00	Day Ahead	System
	9/9/2022	16:00-18:00	Day Ahead	SubLAPs PGNC, PGNP, PGSI, PGST
SmartRate™	8/17/2022	16:00-21:00	Day Ahead	System
	9/1/2022	16:00-21:00	Day Ahead	System
	9/5/2022	16:00-21:00	Day Ahead	System
	9/6/2022	16:00-21:00	Day Ahead	System
	9/7/2022	16:00-21:00	Day Ahead	System
	9/8/2022	16:00-21:00	Day Ahead	System

2.4 REPORT ORGANIZATION

The remaining sections of this report are organized as follows:

- **Section 3 Data and Methods.** This section presents the data and methods used for the PY 2022 evaluation of the ELRP.
- **Section 4 Ex Post Results.** This section presents the ex post analysis results from PY 2022 ELRP participation and supporting analysis.
- **Section 5 Ex Ante Results.** This section presents forecasts of the ELRP ex ante impacts for PY 2022 through PY 2025.
- **Section 6 Comparison Between Ex Post and Ex Ante.** This section discusses the difference between the ex post and ex ante impacts, as well as why they are different.
- **Section 7 Findings and Recommendations.** This section presents the findings and recommendations for the ex post and ex ante impact analysis.
- **Appendices A and B.** These appendices present the ex post and ex ante table generators and proxy event day analyses that support the ex post and ex ante methodology and results.

3 DATA AND METHODS

This section presents the data sources and evaluation methodology used for the PY 2022 ex post and ex ante impact analysis.

3.1 DATA SOURCES

The data sources that are required for the 2022 ELRP evaluation include:

- Participant information and characteristics
- ELRP event information
- Non-ELRP event information for programs associated with dually enrolled participants including BIP Firm Service Level (FSL) commitments.
- AMI (Advanced Metering Infrastructure) interval data for participants and residential non-participants
- Participant and non-participant billing data
- Historical hourly weather and irradiance data
- Ex ante weather scenarios
- Participant enrollment forecasts

Data Collection

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

Customer Information and AMI data. Verdant requested customer information and service point level AMI data for customers enrolled in the ELRP. Given the desire to use a control group for A.6 Residential customers Verdant requested AMI data for all ELRP participants and for the eligible population of residential non-participant customers (after sampling). AMI data was requested from May through October of 2022 and May through October of 2021 for sampled A.6 customers and the non-participant control group. The requested customer information included those necessary to segment the data by the domains of interest (e.g., sector, industry) as well as information to map to any weather stations.

Customer Billing Data. Verdant requested participant billing data and a stratified random sample of non-participant billing data to use for selection of A.6 Residential matched control groups. Billing data was requested for 2021 and 2022.

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

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

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

Participant forecasts. The ex ante forecasts rely on a projection of participation over the forecast horizon. PG&E provided these data. PG&E provided their participant forecasts for relevant ELRP subgroups by customer size, Local Capacity Area, SubLAP and dual enrollment status.

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

3.1.1 PG&E Participant Data Attrition

The evaluation of PG&E's ELRP experienced some level of data attention through various aspects of the analysis. This sub-section details the data attrition.

Non-A.6 Ex Post and Ex Ante Data Attrition

The evaluation of the PY 2022 ELRP attempted to include all PY 2022 A.1 BIP, A.1 General, A.2 BIP, A.4 VPP and B.2 CBP Aggregator participants into the estimation of ex post and ex ante impacts. However, not all of PG&E's PY 2022 participant population were included in the non-A.6 subgroups due to missing or insufficient interval data for modeling impacts. Despite this, data attrition in these groups is fairly low with almost all participants being accounted for in the evaluation of A.1 BIP, A.1 General, A.2 BIP, A.4 VPP and B.2 CBP. Table 3-1 below presents the data attrition by event date and group.

Public Version. Confidential content removed and blacked out.

TABLE 3-1: PG&E NON-A.6 DATA ATTRITION BY EVENT DAY AND SUBGROUP

Sub-group	Metric	PY 2022 ELRP Event Date									
		8/17	8/31	9/1	9/3	9/4	9/5	9/6	9/7	9/8	9/9
A.1 BIP	Num. of Event Parts	0	8	8	8	8	8	8	8	9	9
	Num. of Event Evaluated	0	8	8	8	8	8	8	8	9	9
	Share (%) Evaluated	**--**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
A.1 General	Num. of Event Parts	0	6,255	6,262	6,293	6,293	6,671	6,953	7,094	7,112	7,174
	Num. of Event Evaluated	0	6,126	6,194	6,222	6,223	6,599	6,880	7,018	7,036	7,098
	Share (%) Evaluated	**--**	**98%**	**99%**	**99%**	**99%**	**99%**	**99%**	**99%**	**99%**	**99%**
A.2 BIP	Num. of Event Parts	0	111	112	112	112	112	112	112	112	112
	Num. of Event Evaluated	0	111	111	111	111	111	111	111	111	111
	Share (%) Evaluated	**--**	**100%**	**99%**	**99%**	**99%**	**99%**	**99%**	**99%**	**99%**	**99%**
A.4 VPP	Num. of Event Parts	2,210	2,742	2,783	2,890	3,277	3,460	3,530	3,612	3,697	3,747
	Num. of Event Evaluated	2,201	2,734	2,774	2,880	3,266	3,449	3,518	3,600	3,684	3,734
	Share (%) Evaluated	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
B.2 CBP Aggregator	Num. of Event Parts	0	513	571	571	571	571	571	571	571	571
	Num. of Event Evaluated	0	509	565	565	565	565	565	565	565	565
	Share (%) Evaluated	**--**	**99%**	**99%**	**99%**	**99%**	**99%**	**99%**	**99%**	**99%**	**99%**

A.6 Residential Ex Post and Ex Ante Data Attrition

Data attrition is a more complicated matter for the A.6 participants and cannot be summarized as succinctly as with the other groups. In general, data attrition for A.6 is associated with issues similar to the other groups, such as missing or poor-quality data, but there are several differences for this group that make it difficult to provide a clear accounting. First, the analysis was based on a sample because it would have been impractical to use the nearly two million participants in the program, let alone the number of non-participants required for selection of a control group. Even with relatively large samples, most of the accounts in the population are excluded from the analysis. The second difference is there were additional steps to the analysis related to the development of the control group, each of which introduced the possibility for loss of data. Finally, the estimation of impacts was based on panel data models, which, in contrast to individual customer models, require a relative balance or symmetry in the days of data for each customer. This resulted in the dropping of a small share of customers that for various reasons had data less aligned with the others in the segment.

3.2 EX POST IMPACT METHODOLOGY

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

- Estimating the aggregate and per-customer hourly load impacts and average daily load impacts for each event in PY 2022 and an average event day and relevant domains of interest.
- Calculation of confidence intervals surrounding impact estimates for each hour, as well as the average event hour.

The load impacts were developed for different domains of interest. The domains of interest for each subgroup are presented in Table 3-2 below.

TABLE 3-2: EX POST IMPACT REPORTING DOMAINS OF INTEREST BY SUBGROUP

Reporting Domains	Reporting Group Types	ELRP Subgroup				
		A.1	A.2	A.4	A.6	B.2
Population	All Customers	X	X	X	X	X
Location	LCA, SubLAP, Climate Zone	X	X	X	X	X
NAICS Description	NAICS Description	X	X			X
Customer Size	Load Size Ranges	X	X	X	X	X
Customer Type	Bundled, Direct Access, CCA	X	X	X	X	X
NEM and Technology	NEM Status (general), Solar, Storage, EV	X	X	X	X	X
Dual Enrollment	Dually Enrolled (general), BIP, CBP, CPP, etc.	X	X	X	X	X
Notification Success	Notification Received, Notification Failure				X	
Notification Type	No notification, App, Email, Text				X	
Enrollment Type	HER, CARE/FERA, Self-Enrolled				X	
Disadvantaged Community (DAC)	Census Tract DAC Designation				X	

The ELRP contains multiple subgroups with unique participant characteristics that necessitate different modeling approaches. As a result, the modeling approach for each subgroup varies, but all fall into three categories of modeling approaches. These include individual customer models, panel models with participant fixed effects, and panel modeling with matched control groups.

This section first presents the approaches used for the various subgroups, then goes into greater detail on the general modeling framework, and finally into details on impact estimation and challenges.

3.2.1 Subgroups A.1, A.2, and B.2

Subgroup A.1, A.2 and B.2 all represent non-residential customers that are comprised of a wide variety of industry and load types. As a result, Verdant utilized customer specific regression models for estimation of ex post impacts. This approach allows for varying baselines for each customer, specific to their characteristics and load variability.

3.2.2 Subgroup A.4 VPP

Subgroup A.4 represents ELRP participation through Virtual Power Plants (VPP). For PG&E, all A.4 VPP participants were residential customers. Given the relative homogeneity of residential loads. Verdant utilized panel modeling with participant fixed effects for estimating impacts. Participants were segmented into modeling groups based on LCA, SubLAP, climate zone, customer type, and dual enrollment status. Additional secondary segmentation was used to model the remaining domains of interest, including NEM status and technology types. For segments without sufficient participant counts for panel modeling, customer specific regression models were used in place of panel models.

3.2.3 Subgroup A.6 Residential

Subgroup A.6 represents the residential component of ELRP that was introduced in PY 2022. Enrollment for this group was automatic for PG&E customers in CARE, FERA, and HER programs, though there is also a small set of self-enrolled customers. There are two aspects to this subgroup that set it apart from the others. The first is the sheer quantity of participants (more than 1.5 million), which called for an approach based on sampling. The second is the automatic enrollment for most participants, which makes the use of a control group critical. As a result, panel modeling with non-participant matched control groups was used to estimate the load impacts.

Matched Control Group Development

Verdant used PG&E's premise ID ("prem_uuid") as a proxy for individual households. In the customer data provided, the participant and non-participant populations consisted of 1,710,218 and 2,483,334 unique premises, respectively. However, these data came in separate files and due to nuances in timing of enrollment and de-enrollment, 139,856 unique premises were present in both participant and non-participant populations. Verdant excluded these premises to remove all ambiguity about their participation status. The final counts of unique premises by group (enrollment type for participants and CARE or FERA status for non-participants) that were included in the population frame are presented in Table 3-3.

TABLE 3-3: PARTICIPANT AND NON-PARTICIPANT POPULATION PREMISE COUNTS

Cohort	Group	Unique Premises
Participants	Auto-CARE	1,103,755
	Auto-FERA	32,723
	Auto-HER	413,185
	Self-Enrolled	18,649
	Total	**1,568,312**
Non-Participants	CARE	100,812
	FERA	4,802
	Others	2,237,864
	Total	**2,343,478**

Sampling

As discussed previously, with more than 1.5 million participants, the A.6 participants required sampling for the estimation of impacts.

While there are many domains of interest (disadvantaged communities, customer type, etc.), sampling was based on four main strata:

- Enrollment type
- SubLAP
- NEM
- Smart Rate dual-enrollment.

Excluding the dually enrolled Smart Rate customers, which were treated differently, the three other strata account for 152 segments, with high variability in the number of participants in each. Verdant sampled one thousand participants from each segment, so segments with fewer participants used the entire population. Based on the population frame used for sampling, 86 (~57% of the total) of the segments had fewer than 1,000 participants and relied on the full population. While using the population is generally a good thing, of these segments, around half had fewer than 50 participants, which has ramifications for the ability to model their impacts reliably. The analysis called for a control group, so a sample was also necessary for non-participants. Verdant selected twenty times the sample count from the participant sample, which would allow enough non-participants from which to identify a matched control group.

Matched Control Group Development

As discussed previously, several aspects of the A.6 group call for the use of a control group to reliably estimate impacts. The objective is to find a control group with similar load profiles to the ELRP customers in each of the sampled segments. Verdant relied on stratified propensity score matching (SPSM) with replacement to identify a control group from the broader population of non-ELRP customers. SPSM is based on a logistic regression model that predicts participation as a function of various load characteristics. Because of the large number of accounts in the sample, Verdant conducted SPSM in two stages. The first stage relied on monthly data, which was requested for the complete set of participant and non-participant samples. Monthly data does not allow for matching on load profiles, but it does help to narrow down the non-participant population to customers with similar levels of consumption and weather sensitivity.

The results of the monthly SPSM matching produced a set of potential non-participant matches for each participant. After requesting the interval data for all sample participants and the subset of control group accounts, the next stage repeated the SPSM process, but relying on variables calculated using hourly data.

The objective of the SPSM is to find control groups with similar load profiles to the ELRP customers in the various segments. For the monthly stage of matching, the variables used in the SPSM models included:

- Average daily kWh
- Correlation between kWh and cooling degree days
- Coefficient of variation (COV) for average daily kWh
- Dummy for Presence of EV (if applicable for segment)
- Dummy for TOU rate (if applicable for segment)
- Percent of bills exhibiting export (NEM only)

For the matching using hourly data, the variables used in the SPSM models included:

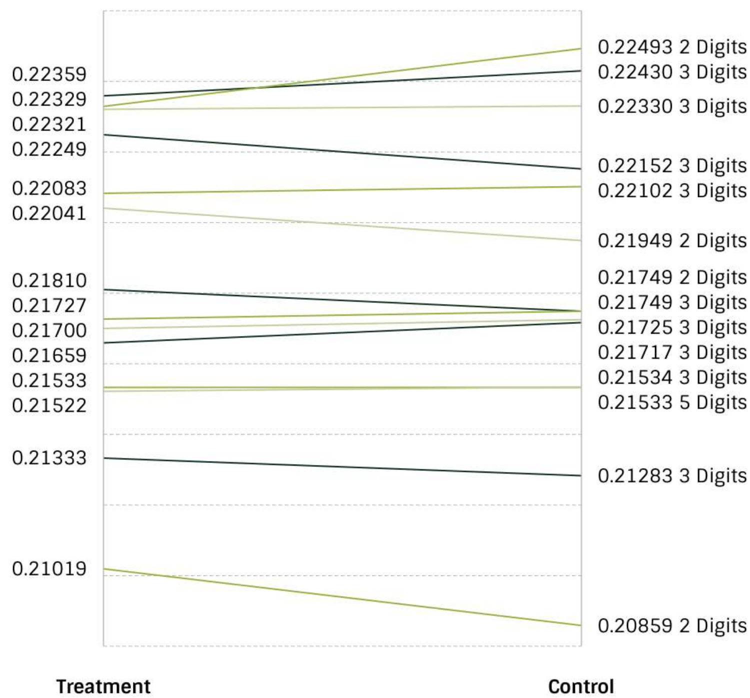
- Average daily kWh
- COV for daily kWh
- COV for hourly kWh
- Average mid-day hourly kWh
- Average evening hourly kWh

- Correlation between hourly kWh and cooling-degree hours
- Percent of hours exhibiting export (NEM only)
- Size of solar system (NEM only)
- Dummy for Presence of EV (if applicable for segment)
- Dummy for TOU rate (if applicable for segment)

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

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

FIGURE 3-1: PROPENSITY SCORE MATCHING EXAMPLE



After this process of selecting the control group accounts, the next step is to validate that the matching process resulted in a good control group. Verdant applied two screens for this validation. The first control group validation was based on independent sample t-tests for the logit model's independent variables where the participant was compared, first, to the full set of candidate control group accounts, and then with just those accounts that were matched to a participant. If the t-tests for the different metrics were not significantly different after selection of the control group, then the control group should be a good match. If there are still metrics with significant differences, then the matching did not produce as reliably similar a control group for the segment. This screen results in thousands of individual tests, so to summarize the results, Table 3-4 shows the number of segments that were modeled along with the count and percentage of t-test results that were statistically significant for, first, the comparison of the participants to the final matched control, and then for the comparison with the full control sample.

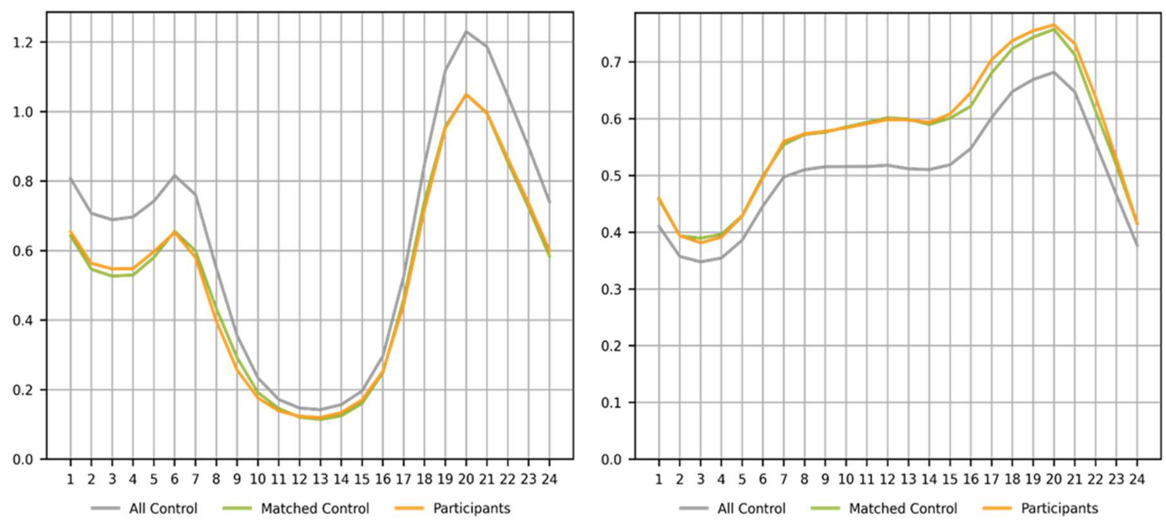
As seen in Table 3-4, of the 130 segments modeled, only two t tests were significantly different when comparing the participants to their matched control customers. In contrast, when comparing the participants to the full control population, the number of significantly different tests is substantial. For example, the correlation between hourly kWh and CDH was significantly different for nearly 62% of the segments. After matching, this was reduced to zero, suggesting that the matching process worked well.

TABLE 3-4: SUMMARY OF T-TESTS RESULTS FROM HOURLY SPSM MATCHING FOR PG&E A.6

SPSM Variable	Segments Modeled	Participants to Matched Control		Participants to All Control	
		# With Significant Difference	% With Significant Difference	# With Significant Difference	% With Significant Difference
COV for daily kWh	130	0	0.0%	35	26.9%
COV for hourly kWh	130	1	0.8%	38	29.2%
EV Dummy	111	1	0.9%	12	10.8%
Average daily kWh	130	0	0.0%	72	55.4%
Average mid-day hourly kWh	130	0	0.0%	71	54.6%
Average evening hourly kWh	130	0	0.0%	68	52.3%
Correlation hourly kWh and CDH	130	0	0.0%	77	59.2%
Percent of hours exhibiting export	70	0	0.0%	30	42.9%
Solar system size	70	0	0.0%	22	31.4%
TOU Dummy	129	0	0.0%	50	38.8%

The second validation is a more subjective visual evaluation of the results where the load profiles for the treatment group are compared with the full set of control group candidates and the final matched group. While there are hundreds of potential comparisons, examples of the profiles for NEM and Non-NEM segments are shown in Figure 3-2, which show the average hourly delivered load profiles for the participants, the matched control, and full control sample. As both figures clearly show, the load profiles for the full control samples are markedly different from the participants, whereas the matched control groups are far more similar.

FIGURE 3-2: LOAD PROFILE VALIDATION FOR NEM (RIGHT) AND NON-NEM (LEFT) SPSM CONTROL GROUP



3.2.4 Ex Post Analysis Framework

There are several analysis steps that are common among all or many of the ELRP subgroups. These steps are detailed here.

Non-Residential Customer Weather Sensitivity

As described above, ELRP A.1, A.2 and B.2 participants make up a wide variety of non-residential customers. The loads of non-residential customers are frequently found to have no relationship to outdoor air temperatures, particularly in larger and more industrial segments. To determine participant weather sensitivity, Verdant applied a simple regression analysis to assess the relationship between load and outdoor temperature. The results were used to determine whether the candidate models for estimating impacts came from a group with various weather variables or from a group based on variables unassociated with weather. Additional details on model groupings are presented below.

Using the interval load and weather data for months in the ELRP event season (May through October), the analysis used regression models of consumption on different thresholds of cooling-degree hours for each participant. If any of these models resulted in a parameter estimate with a probability ("p value") less than .05, the participant was deemed to be weather sensitive for that day type. Table 3-5 shows the count and share of participants who exhibited weather sensitivity by relevant non-residential ELRP subgroups. For the residential participants (A.4 VPP and A.6 Residential) weather is always included in impact baseline modeling. As a result, there is no weather sensitivity analysis conducted for subgroups with only residential participants.

TABLE 3-5: COUNT AND SHARE OF PARTICPANTS EXIHIBITING WEATHER SENSITIVITY BY SUBGROUP

Subgroup	Count	Share
A.1 BIP	4	44%
A.1 General	2,637	37%
A.2 BIP	28	24%
B.2 CBP Aggregator	415	70%

Ex Post Model Groupings and Candidate Models

ELRP non-residential participants and residential segmentations were placed into one of four modeling groups based on their weather sensitivity and NEM solar status. These groups are:

- **Weather Sensitive and NEM:** ELRP participants that exhibit weather sensitivity and are NEM customers; or residential segments that are comprised of NEM customers.
- **Weather Sensitive and Non-NEM:** ELRP participants that exhibit weather sensitivity and are not NEM customers; or residential segments that not comprised of NEM customers.
- **Non-Weather Sensitive and NEM:** Non-Residential participants that do not exhibit weather sensitivity and are NEM customers. Residential customers (A.4 VPP and A.6 Residential) never receive this assignment.
- **Non-Weather Sensitive and Non-NEM:** Non-Residential participants that do not exhibit weather sensitivity and are not NEM customers. Residential customers (A.4 VPP and A.6 Residential) never receive this assignment.

Individual ELRP participants and participant segments in each model group are tested on a similar set of candidate models which include independent variables that are intended to help control for specific characteristics of these participants. For example, the weather-sensitive and non-NEM customers are tested on a set of candidate models that contain various specifications that include variables to account for weather effects on energy consumption. Conversely, non-weather sensitive participants select from a set of candidate models that do not include weather variables in the model specification. An additional feature of these groupings is the inclusion of NEM status. All solar NEM participants have the option to select a model that has weather station irradiance included as an independent variable. The idea is to capture the variability in net energy consumption and delivered load as a result of solar PV production, using irradiance as a proxy for PV production. However, NEM customers are also given the option of selecting models without solar irradiance. Table 3-6 presents the types of variables included in at least one candidate model specification by modeling group.

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

		Model Group			
		Non-Residential Customers and Residential Segments		Non-Residential Customers Only	
Variable Type	**Variable Examples**	**Weather Sensitive and NEM**	**Weather Sensitive and Non-NEM**	**Non-Weather Sensitive and NEM**	**Non-Weather Sensitive and Non-NEM**
Weather	Cooling Degree Hours	✓	✓		
Irradiance	Global Horizontal Irradiance	✓		✓	
Calendar Effects	Month, Day of Week	✓	✓	✓	✓
Baseline Adjustment	Average Morning Load	✓	✓	✓	✓

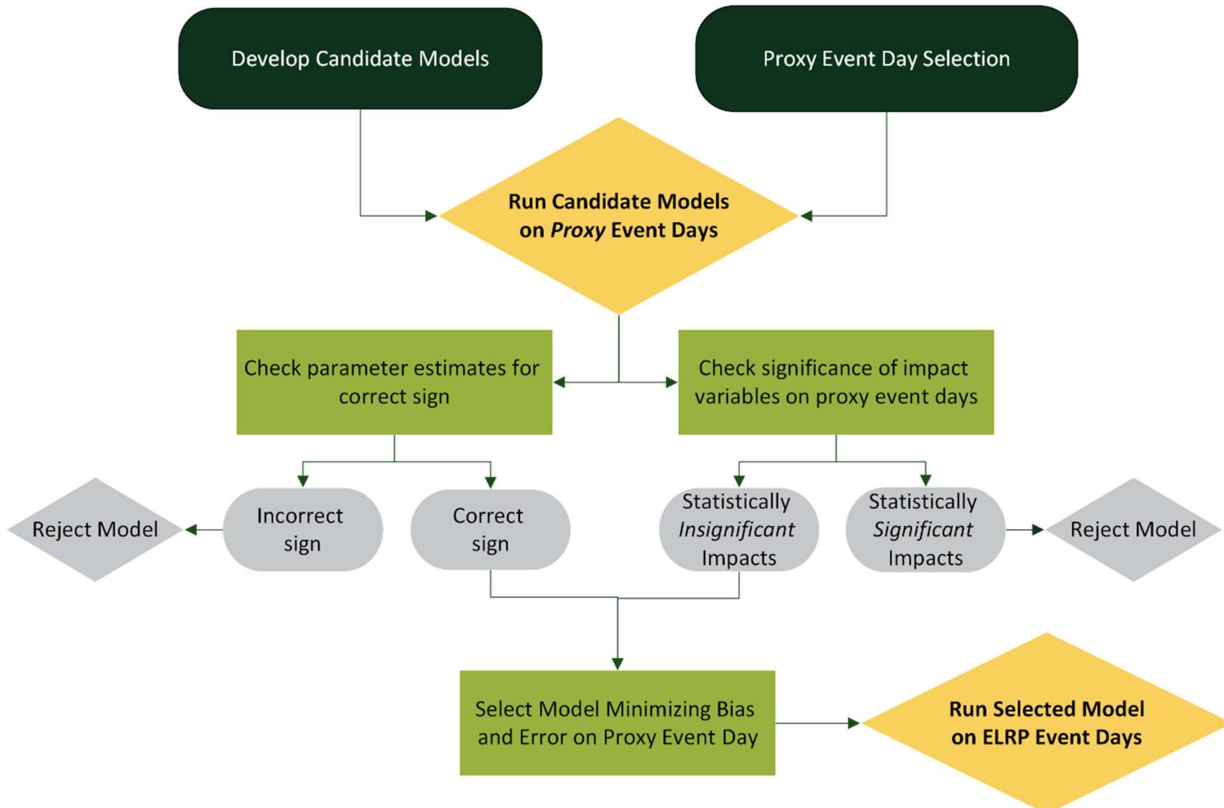
Proxy Event Day Selection

The assessment of candidate model performance relies on the comparison between actual and predicted model performance on a set of days with event-like conditions. These selected days are referred to as proxy event days. For most demand response programs with events coinciding with extreme temperature events, proxy event days are typically the remaining hot non-event days near events. However, some candidate model specifications also have solar irradiance included in the specification. As a result, proxy event days were also selected based on irradiance for non-weather sensitive NEM participants. Five weekdays and three weekend days were selected as proxy event days for each participant based on the maximum average temperatures between 1:00 pm and 11:00 pm. For non-weather sensitive NEM participants, five weekdays and three weekend days were selected based on the average maximum solar irradiance between 1:00 pm and 11:00 pm. For subgroups utilizing some form of panel model (A.4 VPP and A.6 Residential), proxy days represent the five most frequently selected weekdays and three most frequently selected weekdays for participants in each respective modeling segment.

Impact Model Selection

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

FIGURE 3-3: EX POST IMPACT MODEL ARBITRATION



3.2.5 Impact Estimation for Subgroups A.1, A.2 and B.2

The estimation of ex post models for subgroups A.1 General and BIP, A.2 BIP and B.2 CBP Aggregators relies on individual customer specific regression models. Equation 3-1 presents the general model specification used to estimate ex post impacts.

EQUATION 3-1: SUBGROUPS A.1, A.2 AND B.2 GENERAL MODEL SPECIFICATION

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

Where:

$kW\mathrm{h}_{\mathrm{e,d,h}}$	The net load on day *d* in hour *h* during event *e*
β_0	The intercept of the regression model

$EventDay_e Hour_{\mathrm{h}}$	The interaction between the event day dummy and hour. Its coefficient, $\beta_{1e,\mathrm{h}}$, yields the impact of an event on event day *e* during hour *h*
$Temp_{\mathrm{h}}$	A temperature variable in hour *h*.
Irr_{h}	A solar irradiance variable in hour *h*.
$Hour_{\mathrm{h}}$	A dummy variable for each hour *h*
$Month_m$	A dummy variable for each month *m*
$Wday_d$	A dummy variable indicating the day of the week *d*
$OtherEventHour_h$	A dummy variable indicating whether hour *h* is an event hour for a participant in another demand response program
ε	An error term

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

Incremental Load Reductions for Dually Enrolled A.1, A.2 and B.2 Participants

The ELRP contains many dually enrolled participants. This is especially true for A.1 BIP, A.2 BIP, and B.2 CBP aggregators which are comprised entirely of BIP individual customers, BIP aggregators and CBP aggregators (respectively). Additionally, the A.1 General subgroup contains nearly 600 participants that are enrolled in PDP. To accurately estimate incremental load reduction (ILR) impacts, dual participation needs to be accounted for in estimation of event day baselines.

OVERLAPPING BIP AND ELRP EVENT HOURS

As described in Equation 3-1 above, the coefficient $\beta_{7,h}$ is intended to capture other DR program impacts. Since BIP program events only occur on ELRP event days all $\beta_{1e,h}$ coefficients are autocorrelated with $\beta_{7,h}$ for BIP customers. As a result, all impacts in those hours are captured by $\beta_{7,h}$ and $\beta_{1e,h}$ estimates are set to zero. In other words, all impacts during overlapping program event hours are attributed to BIP participation in the modeling of ELRP impacts.

However, the ILR for BIP participants, as defined by program rules, is any load reduction beyond the BIP firm service level (FSL) commitment. The FSL represents a participant's BIP committed level of load reduction. Since the BIP program does not credit BIP participants for load reductions beyond their FSL, any load reductions beyond FSL commitments should be attributed to ELRP participation. As a result, a dually enrolled BIP participant's ELRP baseline during overlapping BIP event hours is the maximum value of the FSL and observed load in that hour. In other words, the ILR is set to the load reductions beyond the

FSL or zero if the BIP FSL is not achieved. Additionally, the uncertainly (impact estimate variance) is set to zero during overlapping BIP event hours as the impacts are not estimated, but rather determined with certainty given stated FSLs and observed load.

DUAL PARTICIPATION IN NON-BIP DR AND ELRP EVENTS

For the estimation of ILR impacts for non-BIP DR programs, there is no systematic issue of autocorrelation between $\beta_{7,h}$ and $\beta_{1e,h}$ estimators as with BIP participation. This is because there is DR participation in other programs (CBP and PDP for example) on days outside of ELRP event days. As a result, other program impacts are captured by $\beta_{7,h}$ and allow for $\beta_{1e,h}$ to represent the ELRP participation effect. When developing the baselines for these participants, only $\beta_{1e,h}$ is added back into the observed load, excluding the typical DR program response from the estimated baseline.

3.2.6 Impact Estimation for Subgroup A.4

The impact estimation approach for A.4 VPP follows closely to the equation used for subgroups A.1, A.2 and B.2. There is one significant difference in the model specification, the model is estimated as a panel data model instead of a site specific model. To capture the individual customer's average consumption, a fixed effect (α_i) is added to the model. Equation 3-2 presents the general model specification used to estimate ex post impacts.

EQUATION 3-2: SUBGROUP A.4 VPP GENERAL MODEL SPECIFICATION

$$kWh_{e,d,h,i} = \beta_0 + \beta_{1e,h}EventDay_eHour_h + \beta_2Temp_h + \beta_3Irr_h + \beta_{4,h}Hour_h + \beta_{5,m}Month_m + \beta_{6,d}Wday_d + \beta_{7,h}OtherEventHour_h + \alpha_i + \varepsilon$$

Where:

$kWh_{e,d,h,i}$	The net load on day *d* in hour *h* during event *e* for participant *i*
β_0	The intercept of the regression model
$EventDay_eHour_h$	The interaction between the event day dummy and hour. Its coefficient, $\beta_{1e,\mathrm{h}}$, yields the impact of an event on event day *e* during hour *h*
$Temp_\mathrm{h}$	A temperature variable in hour *h*.
Irr_h	A solar irradiance variable in hour *h*.
$Hour_\mathrm{h}$	A dummy variable for each hour *h*
$Month_m$	A dummy variable for each month *m*
$Wday_d$	A dummy variable indicating the day of the week *d*
$OtherEventHour_h$	A dummy variable indicating whether hour *h* is an event hour for a participant in another demand response program
α_i	The fixed effect for participant *i* that captures the participant level heterogeneity.
ε	An error term

3.2.7 Impact Estimation for Subgroups A.6

The impact estimation approach for A.6 Residential customers differs in several ways compared to other ELRP subgroups. These include:

- **Estimating each event day hour individually.** Rather than estimating all event hours and impacts together, each hour of the day is modeled separately for A.6 customers. This is done for two reasons. The first is processing time; the sheer volume of participants and matched control groups customers within in each segment results in substantial run times. Estimating each hour individually reduces the amount of time needed for modeling each segment. The second reason is to eliminate the potential for autocorrelation in hour-to-hour load estimates of residential loads.

- **Inclusion of Flex Alert impacts.** The A.6 model specifications include Flex Alert impacts that would be observed in both the ELRP participant population and in the matched control group. Since all A.6 Residential ELRP events are Flex Alert days, we would expect to see load reductions in some portion of the matched control group. For purposes of reporting impacts, the reported total load reduction results are from the combined ELRP and Flex Alert impacts.

Equation 3-3 presents the general model specification used to estimate ex post impacts for subgroup A.6 Residential.

EQUATION 3-3: SUBGROUP A.6 RESIDENTIAL GENERAL MODEL SPECIFICATION

$$kWh_{e,h,i} = \beta_0 + \beta_{1e,h} EventDay_e * Trt_i + \beta_{2e,h} FlexAlert_e + \beta_3 Temp_h + \beta_4 Irr_h + \beta_{5,m} Month_m + \beta_{6,d} Wday_d + \beta_{7,d} OtherEventDay_d + \alpha_i + \varepsilon$$

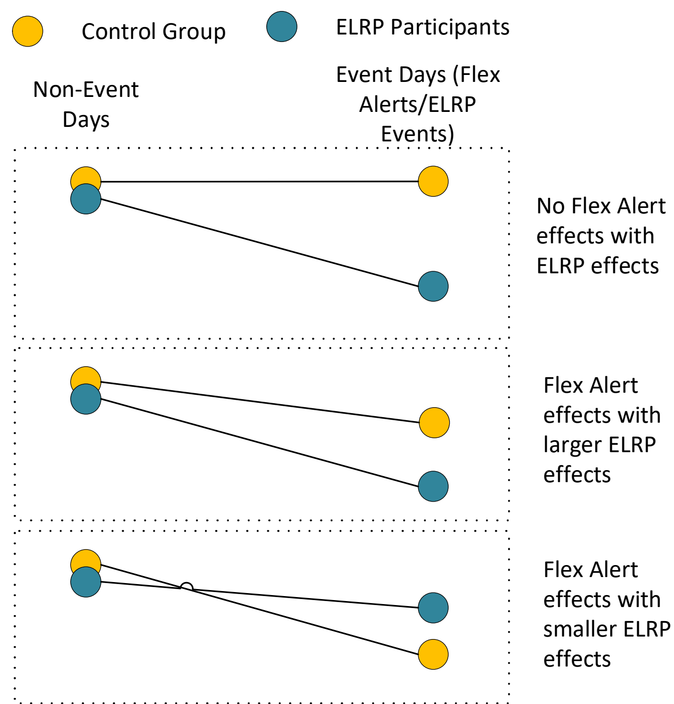
Where:

$kWh_{e,d,h,i}$	The net load on day *d* in hour *h* during event *e* for participant *i*
β_0	The intercept of the regression model
$EventDay_e$	The interaction between the event day dummy and a ELRP treatment dummy. Its coefficient, $\beta_{1e,\mathrm{h}}$, yields the ELRP effect on impact of an event on event day *e* during hour *h*
$FlexAlert_e$	A dummy variable indicating that day *e* is a Flex Alert Day. Its coefficient, $\beta_{2e,h}$, yields the Flex Alert portion of the ELRP impact
$Temp_\mathrm{h}$	A temperature variable in hour *h*.
Irr_h	A solar irradiance variable in hour *h*.
$Hour_\mathrm{h}$	A dummy variable for each hour *h*
$Month_m$	A dummy variable for each month *m*
$Wday_d$	A dummy variable indicating the day of the week *d*
$OtherEventDay_d$	A dummy variable indicating that day *d* is an event day for a dually enrolled participant
α_i	The fixed effect for participant *i* that captures the participant level heterogeneity.
ε	An error term

Residential A.6 Hypothetical Impact Modeling Outcomes and ELRP A.6 Impacts

Given the necessity to control for Flex Alert impacts in A.6 modeling, the resulting approach presents three scenarios for relative load reductions as presented in Figure 3-4. These scenarios depict the relative load reductions between the control group Flex Alert load reductions and the ELRP participant load reductions. As presented, these scenarios are No Flex Alert effects with ELRP effects (top), Flex Alert effects with larger ELRP effects (middle) and Flex Alert impacts with smaller ELRP effects (bottom).

FIGURE 3-4: SUBGROUP A.6 RESIDENTIAL MODELING OUTCOMES

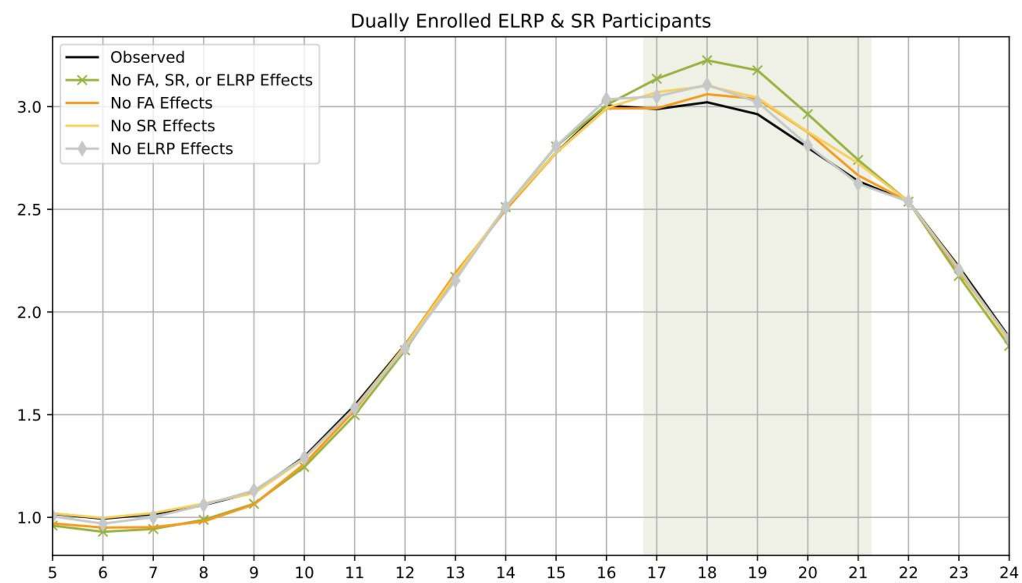


The most common scenario that presents itself (especially for the auto-enrolled segments) in the ex post estimation is the third (bottom) scenario of Flex Alert effects with smaller ELRP effects. The interpretation of this outcome is that ELRP participants reduce their load during the joint ELRP/Flex Alert days, however, they reduce their load to a lesser degree than the control group. This results in a positive value (load increase) for the ELRP coefficient $\beta_{1e,h}$ and a negative value (load decrease) for $\beta_{2e,h}$. Given that the ELRP is intended to compensate participants for Flex Alert load reductions (rather than provide incremental reductions to the Flex Alerts), the ELRP program impacts are the summation of $\beta_{1e,h}$ and $\beta_{2e,h}$.

SmartRate™ Incremental Load Reductions

In addition to the estimation of ELRP program impacts, the evaluation of A.6 also includes the estimation of ILR impacts to the SmartRate™ participation on overlapping event days. To estimate SmarRate™ ILR the evaluation included an additional control group to the analysis comprised of non-ELRP SmartRate™ participants. In total the three customer population groups (ELRP and SmartRate™, SmartRate™ only control group, and No DR control group) results in four demand response baselines. These baselines, as depicted in Figure 3-5 below, are No intervention (light green), No Flex Alert effects (orange), no SmartRate™ Effects (yellow), and no ELRP effects (grey). The ELRP impacts incremental to SmartRate™ are derived from the no ELRP effects counterfactual (grey) presented in Figure 3-5.

FIGURE 3-5: EXAMPLE OF SMARTRATE™ PARTICIPANT INCREMENTAL LOAD REDUCTION BASELINES



3.3 EX ANTE IMPACT METHODOLOGY

The goal of the ex ante impact analysis is to estimate program impacts for future years under varying 1-in-10 and 1-in-2 weather scenarios across the ELRP event window (4:00 pm to 9:00 pm).[11] Given that the ELRP is a pilot program, the ex ante analysis seeks to provide ex ante estimates for program years 2023 through 2025. The ex ante analysis only seeks to estimate impacts for subgroups that actively participated

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

in events in PY 2022. The primary reason is that there was no event participation for Groups A.3 and A.5 for PG&E. As a result, there are no ex post impacts to inform a LIP-based ex ante analysis.

Ex ante impacts are estimated in two ways. These include program level ex ante impacts and the portfolio adjusted ex ante impacts. The program level ex ante impacts represent forecasted program impacts on ELRP-only event days and only include impacts from the ex post analysis in which there is no other DR participation on that day for dually enrolled participants. Conversely, portfolio adjusted ex ante impacts represent ex ante impacts that are incremental to the entire portfolio of PG&E's DR programs and represent ILRILR impacts. Compensation structures differ for dually enrolled participants and there is no mechanism or penalty structure that ensures reliable participation in ELRP. As a result, there are cases where the portfolio adjusted impacts are larger than the program level impacts. An example of this scenario is for BIP dually enrolled participants who are only compensated for ILR during overlapping BIP event hours and are not compensated on ELRP-only event days. As result load impacts are larger on dual program days (portfolio level) than on days in which there is only an ELRP event.

3.3.1 Ex Ante Impacts - Non.A.6

The ex ante impacts are derived from the weather-normalized ex post impacts and follow the standard practice outlined in the Load Impact Protocols. However, the results from the ex post analysis required some modifications to produce bottom-up ex ante analysis. The ex post analysis estimates weekend and weekday event impacts separately for A.1, A.2 and B.2. However, in the ex ante impacts model, the weekend and weekday impacts were estimated together which necessitates a slight modification to the individual participant weekday models used for ex post estimation. These adjustments include:

- The ex post model term $\beta_{1e,h} EventDay_e Hour_h$ impact estimator was altered to $\beta_1 EventHour$ for non-weather sensitive customers and to $\beta_1 CDH65 * EventHour$ for weather sensitive participants, where the $EventHour$ is the dummy variable indicating an event hour and $CDH65$ is a seasonal weather variable. For summer cooling sensitive customers, the CDH65 term allows for ex ante impacts to "adjust" accordingly in each weather scenario. Additionally, the $\beta_1 EventHour$ parameters were interacted with event hour to address ELRP participant fatigue through the five-hour ELRP event window.

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

Additionally, the model specification differs from the ex post model specification by interacting the event hour coefficient with the fixed effects that represent the n^{th} hour of an event. The goal of this is to attribute event fatigue to event impacts throughout the five-hour resource adequacy (RA) window.

After development of weather normalized impacts, the impacts are then weighted by the ex ante participant forecasts provided by PG&E to account for the distributions of forecasted ELRP participants. More specifically, participants are weighted based the forecasted distributions of customer size, Local Capacity Area and SubLAP.

3.3.2 Ex Ante Impacts A.6

For the A.6 subgroup, the ex ante impact methodology largely followed that of the other groups, but there were several difference. First, two aspects made the overall approach less complicated. First, all A.6 events occurred during the same 4:00 PM to 9:00 PM window, eliminating any ambiguity related to modeling events where the start and end times vary. Second, while a weekend variable was included in the model, the load profiles and impacts did not vary in any meaningful way, so the ex ante estimates were based on a the assumption that the events would occur on a weekday.

In addition to the above simplifications to the approach, another change was the exclusion, for a subset of SubLAPs, of up to four of the hotter event days for modeling. The justification for this was that 2022's weather was atypical, particularly for certain coastal areas that had atypically hot days, all of which fell on ELRP events. In the ex post modeling, with no hot non-event days, the unfortunate result of this was that in the absence meaningful curtailment among the auto-enrolled populations, the regression models captured the temperature effects in the impact variables. Since these increases are not "real," but rather byproducts of the anomalous weather, the evaluators deemed that it was best to simply exclude these hotter days from the ex ante modeling so as to not mischaracterize the impacts.

Finally, event fatigue was not explicitly modeled. This analysis was not necessary given the single event window, which would allow any fatigue to be ascertained from the event hour results. In the words, to assess fatigue, one can see how the impacts later in the event compare to the early hours.

3.3.3 Ex Ante Forecasts

PG&E provided their participant enrollment forecasts which are presented in Table 3-7. PG&E forecasts an annual growth rate of 100 thousand additional participants each year for subgroup A.6 Residential customers. There is a slight decrease in subgroup A.1 enrollment through PY 2025 due to assumed attrition for PDP. Additionally, there is attrition assumed in A.6 SmartRate™ dual customers. For all other subgroups the forecasts are constant through the life of the pilot. Note that the enrollment forecasts include A.3 and A.5 participation, but they are not included in the ex ante evaluation.

TABLE 3-7: PG&E EX ANTE PARTICIPANT ENROLLMENT FORECAST BY YEAR SUBGROUP

Subgroup	PY 2023	PY 2024	PY 2025
A.1	7,040	7,009	6,981
A.2	112	112	112
A.3	0	0	0
A.4	4,292	4,292	4,292
A.5	3	3	3
A.6	1,676,947	1,776,947	1,876,947
B.2	600	600	600

3.3.4 COVID-19 Ex Ante Adjustments

PG&E provided their assumed sector level Covid-19 impacts which represent the adjustment from the Covid-19 free baseline as a percentage. Covid-19 effects are expected to completely subside by the summer of 2023. Verdant converted these percentages into a multiplier for ex ante baseline load. Given that baseline effects are expected to completely disappear in 2023, adjustment factors are the same for all years in the ex ante period. Ex ante adjustment factors are presented in Table 3-8 for each month and sector.

TABLE 3-8: PG&E EX ANTE COVID-19 BASELINE ADJUSTMENT FACTORS BY MONTH AND SECTOR

Sector	May	June	July	August	September	October
Residential	0.98	0.99	0.99	0.99	0.99	0.99
Small/Medium Commercial	1.05	1.05	1.04	1.04	1.04	1.03
Large Industrial	1.02	1.02	1.02	1.02	1.02	1.01

3.4 UNCERTAINTY ADJUSTED IMPACTS

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

3.5 USE OF NET AND DELIVERED LOAD

The ELRP evaluation stands out compared to other DR load impacts evaluations in its use of net load and delivered load rather than only delivered load. The reason for the use of net load is that multiple subgroups allow or require the use of net load for participant compensation. Subgroups A.1 and B.2 allow for participants to elect to use NEM resources for participation and to be compensated via net load reductions. Additionally, A.4 requires the use of net load. As a result, all segments are evaluated using net load with the addition of impacts also being estimated using delivered load for subgroups A.2 and A.6.

3.6 MODELING CHALLENGES

Every load impact evaluation has a distinctive set of challenges when modeling impacts. The analysis of A.6 Residential has an exceptional set of challenges that are worth noting. These challenges include auto-enrollment, availability of customers for a matched control group, and Flex Alerts.

Typically, matched control group customers are identified through some sort of matching methodology. However, the ELRP auto-enrolled all CARE, FERA, and HER participants into the ELRP. As a result, there are no CARE, FERA or HER non-ELRP customers of a reasonable sample size to use as a matched control group. While the evaluation was able to find suitable candidates for matched control groups from the general residential customer population, these matches are based on historical energy consumption, NEM status, and customer size. The matched control groups cannot account for behavioral or household characteristics of CARE, FERA or HER that may influence the way in which these participants interact with ELRP and Flex Alert events. The analysis would benefit from the inclusion of non-ELRP CARE, FERA and HER customers to help account for these behavioral changes. These customers, however, do not exist due to the autoenrollment of these entire populations.

Additionally, the existence and response to Flex Alerts in the participant and matched control group requires that Flex Alerts be accounted for in the modeling of A.6 residential impacts. Typically, matched control groups help control for extreme weather and idiosyncratic events that affect the overall utility customer population (such as a flex alert). In a sense, the matched control group helps solidify the counterfactual baseline and ensures impacts are solely a result of DR interventions. However, for 2022, except for one Flex Alert event, all ELRP and Flex Alert events occurred on the same days. This reduced the ability of the control group to capture weather effects on ELRP event days because the control group and ELRP participants were subject to similar influences. Stated succinctly, there were few days with extreme temperatures where the control group was not subject to a Flex Alert event, which limited the ability to estimate baseline sensitivity to high temperatures. To help account for this, Verdant excluded days from the analysis that were not sufficiently hot enough to provide useful information into the regression analysis.

4 EX POST RESULTS

The primary objective of the ex post analysis is to provide estimates of event day load reductions and for an average event day. There were ten event days for PG&E with varying event hours for non-A.6 subgroups. The average event day for PG&E subgroups A.1 General, A.4 VPP and B.2 CBP aggregators includes the average hourly impacts and participation across all event days with at least three hours in duration. These events make up the majority of ELRP events and minimize the dilution of average event day impacts by limiting the number of non-event hours represented in the average event day. The event hours for subgroup A.6 residential are always from 4 to 9 pm by program design, as a result the average event day includes all event days.

While all subgroup A.1 BIP and A.2 BIP participants were notified of each ELRP event, they are only compensated for participation during overlapping BIP event hours. As a result, it would be reasonable to only expect load reductions on event days with overlapping BIP event hours. Therefore, the average event day for A.1 BIP and A.2 BIP only includes dual BIP event days (September 5th, 6th, and 7th).

This section discusses each ELRP subgroup individually. First, we present the average event day load shapes, then we address hourly averages of per capita and aggregate event day impacts, the average by subgroup, and then applicable special topics for each subgroup. ELRP impacts are estimated using net load for all segments with the addition of delivered load for subgroups A.2 BIP and A.6 Residential.

Interpreting Average Event Day Load Shapes

Visually representing event day load shapes and estimated baselines is a powerful tool for understanding event day activity and for framing impact estimates. For this reason, this report first presents event day load shapes for each subgroup's average event day before discussing the impacts for separate events. Given that events occurred on varying hours across event days, the density of the shaded areas relates to the frequency of event days where a given hour was an event hour. The opaquer the shading on an event hour, the more frequently that hour was an event hour.

Additionally, ELRP impacts represent ILR. As a result, the ex post baseline includes other DR program impacts, which presents visually as a kink in the ELRP baseline. This is most noticeable in the A.1 BIP, A.2 BIP, and B.2 CBP Aggregator load shapes (Figure 4-1, Figure 4-5, and Figure 4-14 respectively).

4.1 SUBGROUP A.1 BIP EVENT DAY IMPACTS

Figure 4-1 below presents the average event day aggregate load shape for subgroup A.1 BIP. As stated previously, the average event day for this subgroup only includes dual ELRP and BIP event days. While the days solely represent dual ELRP and BIP days, not all event hours are dual program event hours. Hours ending 17 and 18 are always ELRP-only event hours, while hours ending 19, 20 and 21 contain some level of BIP impacts (either partially or completely). As a reminder, the ELRP baseline during dual BIP and ELRP event hours is the incremental reduction exceeding a BIP participant's FSL (the maximum value of the participant's observed load and the FSL). For ELRP-only hours, the baseline is the estimated regression baseline.

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

[redacted]

Table 4-1 provides the average event hour impacts for each event day for PG&E Subgroup A.1 BIP. On average, Subgroup A.1 BIP participants provided an average of [redacted] MWh of load reduction in each ELRP event hour on dual BIP and ELRP event days. The largest estimated average hourly MWh load reduction occurred on September 8th, 2022, with an average hourly load reduction of [redacted] MWh (or [redacted] of the estimate baseline). Notably, this was not a BIP event day for which dually enrolled BIP customers are compensated. These results suggest that BIP customers do reduce their load for ELRP-only days despite the lack of compensation, but not necessarily for all events. As seen in the table below, there were no load impacts on August 31st or September 1st, which is in line with expectations for non-compensated load reductions.

TABLE 4-1: PG&E PY 2022 ELRP AVERAGE EVENT HOUR IMPACT – SUBGROUP A.1 BIP

Event Date	Event Window	Num. of Customers	Avg. Per Capita Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. Aggregate MW Impact Reduction (MWh/h)	Avg. Temp (F)
8/31/2022	17:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/1/2022	18:00-19:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/3/2022	18:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/4/2022	17:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/5/2022*	17:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/6/2022*	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/7/2022*	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/8/2022	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/9/2022	16:00-18:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Avg. Event	--	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

*Indicates a dual BIP and ELRP Event Day

4.1.1 Subgroup A.1 BIP ELRP-Only Event Day Load Shape

Figure 4-1 previously described the average event day for A.1 BIP participants which consists exclusively of dual ELRP and BIP event days. However, it is also worth discussing the impacts for ELRP-only event days. While BIP participants are not compensated for ELRP load reductions on event days, they are notified and there is evidence of load curtailments (especially for non-ELRP events during the first 10 days of September).

Figure 4-2 below presents the average load shape for all ELRP-only events. As presented, there are event day load reductions, on average, during ELRP-only events days. The largest hourly load reductions occur in hours ending 17 and 18 and then get progressively smaller throughout the event window. This is consistent with event fatigue and is expected for uncompensated load reductions. However, it should also be noted that not all hours were event hours on each day.

FIGURE 4-2: PG&E A.1 BIP AVERAGE PER CAPITA LOAD SHAPE – ELRP ONLY EVENT DAYS

[redacted]

4.1.2 Subgroup A.1 BIP Average Event Day Impacts by Domain

Next, we present A.1 BIP impacts by the varying domains of interest. For ease of the reader, domains of interest are split into two groups, geography and participant characteristic domains. Geography domains, presented in Table 4-2, include climate zone, Local Capacity Area, and SubLAP. Participant characteristic domains, presented in Table 4-3, consist of customer size, customer type, NAICS Description, and NEM status and technology type. Dual enrollment status is excluded from the table because all participants are dually enrolled in BIP.

Public Version. Confidential content removed and blacked out.

TABLE 4-2: PG&E SUBGROUP A.1 BIP AVERAGE EVENT DAY IMPACTS BY GEOGRAPHY DOMAINS

Domain	Sub-Domain	Num. of Customers	Avg. Per Capita Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. Aggregate MW Impact Reduction (MWh/h)	Avg. Temp (F)
All	All	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Climate Zone	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Local Capacity Area	Greater Bay Area	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Humboldt	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Stockton	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SubLAP	SLAP_PGEB	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SLAP_PGHB	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SLAP_PGP2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SLAP_PGSB	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SLAP_PGST	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SLAP_PGZP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

TABLE 4-3: PG&E SUBGROUP A.1 BIP AVERAGE EVENT DAY IMPACTS BY PARTICPANT CHARACTERISTICS

Domain	Sub-Domain	Num. of Customers	Avg. Per Capita Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. Aggregate MW Impact Reduction (MWh/h)	Avg. Temp (F)
All	All	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Customer Size	200KW or Greater	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Customer Type	CCA (Comm Choice Aggregation)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	DA (Direct Access)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	FS (Full Service)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NAICS Description	Agriculture, Mining & Construction	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Manufacturing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Offices, Hotels, Finance, Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Retail Stores	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Wholesale, Transport, Other Utilities	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Technology Type	None	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Storage, Solar PV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

4.2 SUBGROUP A.1 GENERAL EVENT DAY IMPACTS

Figure 4-3 presents the average event day aggregate impact load shape for Subgroup A.1 General[12]. The A.1 General participants are largely ELRP-only participants, however, there are roughly 600 participants dually enrolled in PDP. As presented in the figure below and described in Table 4-4, impacts in this customer segment were fairly modest with an average hourly percent load reduction of [redacted] % of load and an average hourly load impact [redacted] MWh ([redacted] kWh per capita).

[12] A.1 General is marked confidential due to one participant making up more than 15% of event day loads.

FIGURE 4-3: PG&E AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – SUBGROUP A.1 GENERAL

[redacted]

Figure 4-3 further details the event day specific average hourly impacts for A.1 General participants. The average hourly percent load reductions ranged from [redacted] % across event days, with the largest impacts occurring on September 9th and the smallest impacts occurring on August 31st.

TABLE 4-4: PG&E PY 2022 ELRP AVERAGE EVENT HOUR IMPACT – SUBGROUP A.1 GENERAL

Event Date	Event Window	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
8/31/2022	17:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/1/2022	18:00-19:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/3/2022	18:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/4/2022	17:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/5/2022	17:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/6/2022	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/7/2022	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/8/2022	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/9/2022	16:00-18:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Avg. Event	--	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

4.2.1 Subgroup A.1 General Average Event Day Impacts by Domain

Next, A.1 General impacts by the varying domains of interest are presented in Table 4-5 (geography) and Table 4-6 (participant characteristics). In Table 4-5, the results show that the largest share of impacts are from participants in the [redacted] [redacted] average hourly event day impact). In Table 4-6 customers with [redacted] provide the largest share of load impacts despite having a smaller share of the participant population. Larger customers curtail a smaller percentage of their load but tend to provide larger per capita impacts.

Public Version. Confidential content removed and blacked out.

TABLE 4-5: PG&E SUBGROUP A.1 GENERAL AVERAGE EVENT DAY IMPACTS BY GEOGRAPHY DOMAINS

Domain	Sub-Domain	Num. of Customers	Avg. Per Capita Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. Aggregate MW Impact Reduction (MWh/h)	Avg. Temp (F)
All	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Climate Zone	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	11	599	21.0	0.3	1.6%	0.2	98.8
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	13	3,666	36.5	1.7	4.6%	6.1	105.3
Local Capacity Area	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Greater Fresno Area	2,470	27.6	1.5	5.6%	3.8	104.8
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Kern	353	42.1	2.1	5.0%	0.7	105.5
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Other	1,681	52.5	2.5	4.8%	4.2	102.6
	Sierra	422	29.0	1.0	3.4%	0.4	99.4
	Stockton	321	16.1	0.5	2.8%	0.1	102.5
SubLAP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SLAP_PGF1	2,489	27.5	1.5	5.5%	3.8	104.8
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SLAP_PGKN	321	39.8	1.6	4.0%	0.5	105.6
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SLAP_PGP2	296	101.0	4.8	4.7%	1.4	88.2
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SLAP_PGSF	134	293.4	20.7	7.1%	2.8	77.2
	SLAP_PGSI	422	29.0	1.0	3.4%	0.4	99.4
	SLAP_PGST	319	15.9	0.5	2.8%	0.1	102.4
	SLAP_PGZP	1,233	58.9	3.0	5.1%	3.7	103.4
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Public Version. Confidential content removed and blacked out.

TABLE 4-6: PG&E SUBGROUP A.1 GENERAL AVERAGE EVENT DAY IMPACTS BY PARTICPANT CHARACTERISTICS

Domain	Sub-Domain	Num. of Customers	Avg. Per Capita Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. Aggregate MW Impact Reduction (MWh/h)	Avg. Temp (F)
All	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Customer Size	Under 20 kW	2,650	1.4	0.3	19.7%	0.7	99.5
	20 kW to 199.99 kW	3,199	32.5	1.5	4.6%	4.8	101.0
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Customer Type	CCA (Comm Choice Aggregation)	1,339	73.6	3.7	5.0%	5.0	91.0
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	FS (Full Service)	5,028	34.5	0.4	1.1%	1.9	103.1
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dually Enrolled	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	PDP	625	37.3	1.1	2.9%	0.7	98.4
NAICS Description	Agriculture, Mining & Construction	3,876	26.2	1.6	6.1%	6.2	103.7
	Institutional/Government	469	83.4	0.3	0.4%	0.1	96.0
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Offices, Hotels, Finance, Services	1,026	186.3	9.1	4.9%	9.3	92.0
	[redacted]	15	11.3	-16.5	-145.6%	-0.2	100.8
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unknown NAICS Description	67	24.2	4.2	17.5%	0.3	103.0
	Wholesale, Transport, Other Utilities	986	27.9	1.9	6.9%	1.9	97.6
NEM Status	NEM	911	63.0	2.8	4.5%	2.6	102.6
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

4.2.2 Subgroup A.1 General PDP Dually Enrolled Event Day Impacts

Figure 4-4 presents the average event day per capita impact load shape for subgroup A.1 General PDP dually enrolled participants. As presented in the figure below and described in Table 4-7, impacts in this customer segment were fairly modest with an average hourly percent load reduction of 2.9% of load and an average hourly load impact 0.7 MWh (1.1 kWh per capita).

FIGURE 4-4: PG&E AVERAGE EVENT DAY PER CAPITA LOAD IMPACT – SUBGROUP A.1 GENERAL PDP DUALLY ENROLLED

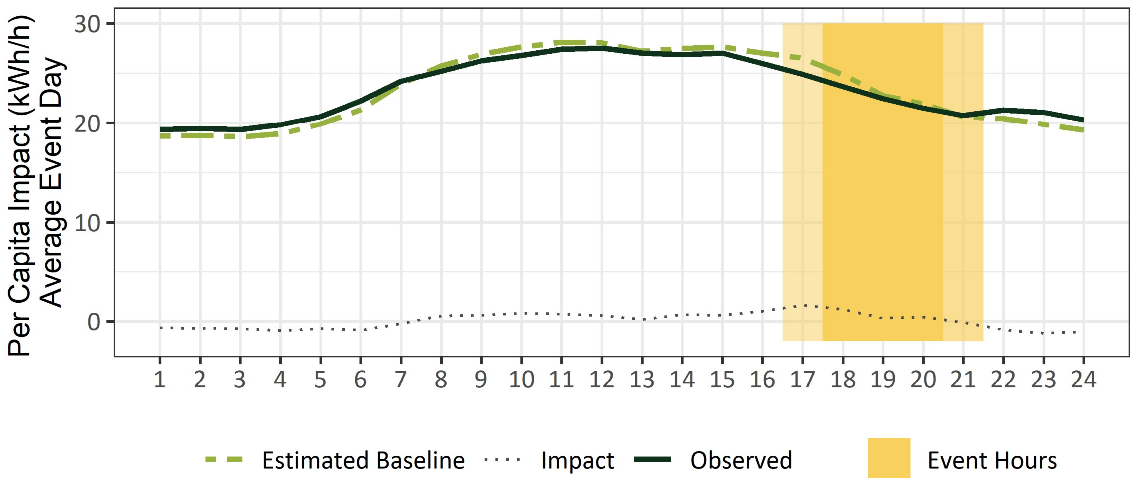


Table 4-7 further details the event day specific average hourly impacts for A.1 General PDP participants. September 1st, September 5th, September 6th, and September 7th were PDP event days. Overlapping event hours with PDP represent impacts that are incremental to the PDP program, based on modeling of a typical event day. The average hourly percent load reductions ranged from -4.5% to 5.0% across event days, with the largest impacts occurring on September 6th which is a PDP event day. The PDP event hours coincide with the entire ELRP event window of 4 to 9 pm. This suggests that there are impacts from PDP participants that are incremental to PDP. Additionally, ELRP ILR impacts on PDP days are typically larger than impacts provided on ELRP-only event days, suggesting that PDP participants are more motivated for curtailment when they are already being dispatched for PDP participation.

TABLE 4-7: PG&E PY 2022 ELRP AVERAGE EVENT HOUR IMPACT – SUBGROUP A.1 GENERAL PDP PARTICIPANTS

Event Date	Event Window	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
8/31/2022	17:00-20:00	562	31.7	-0.6	-1.9%	-0.3	91.5
9/1/2022*	18:00-19:00	562	28.5	-0.6	-2.0%	-0.3	96.1
9/3/2022	18:00-20:00	562	25	-1.1	-4.5%	-0.6	92.7
9/4/2022	17:00-20:00	562	25.0	-0.2	-1.0%	-0.1	98.4
9/5/2022*	17:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/6/2022*	16:00-21:00	634	46	2.3	5.0%	1.4	102.7
9/7/2022*	16:00-21:00	683	41.4	2	4.9%	1.4	99.1
9/8/2022	16:00-21:00	685	41.1	1.4	3.3%	0.9	98.9
9/9/2022	16:00-18:00	695	42.1	1	2.3%	0.7	98.9
Avg. Event	--	625	37.3	1.1	2.9%	0.7	98.4

*Indicates a dual PDP and ELRP Event Day

4.3 SUBGROUP A.2 BIP EVENT DAY IMPACTS

Figure 4-5 below presents the average event day aggregate load shape for subgroup A.2 BIP calculated with both delivered and net load. In general, there is little difference between results generated with net and delivered load, largely due to the small number of NEM participants included in subgroup A.2 BIP.

As with A.1 BIP, the average event day for this subgroup only includes dual ELRP and BIP event days. While the average event day solely represents dual ELRP and BIP days, not all event hours are dual program event hours. Hours ending 17 and 18 are always ELRP only event hours, while hours ending 19, 20 and 21 contain some level of BIP impacts (either partially or completely). As a reminder, the ELRP baseline during dual BIP and ELRP event hours is the incremental reduction exceeding a BIP participant's FSL (the maximum value of the participant's observed load and the FSL). For ELRP-only hours, the baseline is the estimated regression baseline.

FIGURE 4-5: PG&E AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – SUBGROUP A.2 BIP

[redacted]

Table 4-8 and Table 4-9 provide the average event hour impacts for each event day for PG&E Subgroup A.2 BIP for delivered load and net load respectively. Given that there is little difference between impacts estimated with net and delivered load, the discussion is largely focused on impacts from delivered load. By definition, impacts are the same for delivered and net load for all customers except NEM customers.

On average, Subgroup A.2 BIP participants provided an average of [redacted] MWh of load reduction in each ELRP event hour on dual BIP and ELRP event days. The largest estimated average hourly MWh load reduction occurred on [redacted], with an average hourly load reduction of [redacted] MWh (or [redacted] % of the estimated delivered load baseline). Notably, this was a BIP event day for which dually enrolled BIP customers are compensated for load reduction beyond their FSL. The results presented in Table 4-8 below suggest that BIP customers do reduce their load for ELRP-only days despite the lack of compensation, but not necessarily for all events and to a lesser degree than on BIP event days. This is in-line with expectations for non-compensated load reductions.

While program rules do not allow A.2 participants to be compensated based on net load reductions, there is a slight increase in load reductions based on net load compared to delivered load (XX MWh in aggregate compared to [redacted] MWh). Intuitively this makes sense - export to the grid provides additional load reductions that are not captured in the delivered load analysis.

TABLE 4-8: PG&E PY 2022 ELRP AVERAGE EVENT HOUR IMPACT – SUBGROUP A.2 BIP – DELIVERED LOAD

Event Date	Event Window	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
8/31/2022	17:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/1/2022	18:00-19:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/3/2022	18:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/4/2022	17:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/5/2022*	17:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/6/2022*	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/7/2022*	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/8/2022	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/9/2022	16:00-18:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Avg. Event	--	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

*Indicates a dual BIP and ELRP Event Day

TABLE 4-9: PG&E PY 2022 ELRP AVERAGE EVENT HOUR IMPACT – SUBGROUP A.2 BIP – NET LOAD

Event Date	Event Window	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
8/31/2022	17:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/1/2022	18:00-19:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/3/2022	18:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/4/2022	17:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/5/2022*	17:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/6/2022*	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/7/2022*	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/8/2022	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/9/2022	16:00-18:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Avg. Event	--	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

*Indicates a dual BIP and ELRP Event Day

4.3.1 Subgroup A.2 BIP ELRP-Only Event Day Load Shape

Figure 4-5 presented the average event day for A.2 BIP participants which consists exclusively of dual ELRP and BIP event days. However, it is also worth discussing the impacts for ELRP-only event days. While BIP participants are not compensated for ELRP load reductions on ELRP-only event hours, they are notified of all events and there is evidence of load curtailments, although it is more modest compared to individually enrolled BIP customers in A.1 BIP.

Figure 4-6 below presents the average load shape for all ELRP-only events. There are event day load reductions, on average, during ELRP only events days. Although these reductions are modest in terms of a percentage of load, average hourly aggregate load reductions are [redacted] MWh on ELRP only days.

FIGURE 4-6: PG&E AVERAGE ELRP ONLY DAYS PER CAPITIA LOAD IMPACT – SUBGROUP A.2 BIP – DELIVERED LOAD

[redacted]

4.3.2 Subgroup A.2 BIP Average Event Day Impacts by Domain

A.2 BIP delivered load impacts by the varying domains of interest are presented in Table 4-10 and Table 4-11 below for geography and participant characteristics respectively. By geographic domain, the largest share of impacts is located in [redacted] ([redacted] MWh of the [redacted] MWh average hourly event day impact.)

TABLE 4-10: PG&E SUBGROUP A.2 BIP AVERAGE EVENT DAY IMPACTS BY GEOGRAPHY DOMAINS

Domain	Sub-Domain	Num. of Customers	Avg. Per Capita Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. Aggregate MW Impact Reduction (MWh/h)	Avg. Temp (F)
All	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Climate Zone	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Local Capacity Area	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SubLAP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

TABLE 4-11: PG&E SUBGROUP A.2 BIP AVERAGE EVENT DAY IMPACTS BY PARTICPANT CHARACTERISTICS

Domain	Sub-Domain	Num. of Customers	Avg. Per Capita Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. Aggregate MW Impact Reduction (MWh/h)	Avg. Temp (F)
All	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Customer Size	20 kW to 199.99 kW	24	28.8	7.0	24.2%	0.2	106.2
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Customer Type	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NAICS Description	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Wholesale, Transport, Other Utilities	33	287.1	70.5	24.6%	2.3	100.7
NEM Status	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Technology Type	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

4.4 SUBGROUP A.4 VPP EVENT DAY IMPACTS

Figure 4-7 presents the average event day aggregate impact load shape for subgroup A.4 VPP. Given that all A.4 VPP participate have battery storage, and the vast majority of participant's batteries are paired with solar, it is worth discussing the average event load shape as it differs from more traditional DR resource types.

There are two distinct deviations from the baseline reference load. The first deviation occurs between hours ending 9 and 17, where load is increased relative to the baseline load. This load increase is the result of battery charging from solar PV in a way that is not typical on non-event days. Battery charging prior to the event in the solar production window does not occur on all event days, however it does occur on all event days that follow another. Pre event charging is discussed in greater detail later in this section in Section 4.4.1.

The second deviation is the actual load curtailment. Typically, A.4 participants (all under one aggregator) dispatched their load for only two hours (most commonly hours ending 19 and 20) regardless of the length of the event window. This curtailment behavior is also discussed in Section 4.4.1.

FIGURE 4-7: PG&E AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – SUBGROUP A.4 VPP

[redacted]

4.4.1 Subgroup A.4 Event Day Load Reduction Behaviors

Before discussing event day A.4 VPP impacts, this section first discusses event day battery charging and event dispatch behaviors to provide greater context for reported numbers. Event day dispatch is discussed followed by event day battery charging.

As previously discussed, the A.4 VPP participants are generally all dispatched over the same hours. However, impacts are never sustained for more than two to three hours, regardless of the ELRP event duration. Figure 4-8 presents the four individual ELRP event days of varying duration. The events are one, three, four, and five hours in duration, respectively. As seen in the figure, full levels of load curtailments last only for a maximum of two hours and then severely dissipate in the third hour. Given that the ELRP is a no penalty program, there is not an incentive to provide impacts that can be sustained across the entire event window. Rather the battery appears to completely discharge in the first two to three hours of curtailment to provide maximum load reductions in those hours.[13] Given that there is also some level of pre-curtailment battery charging on consecutive event days and snapback after full curtailment, the load reductions across the event window, on average, are smaller for events with longer event durations.

[13] The level of battery discharge and capacity cannot actually be known without battery telemetry data. It is the evaluator's hypothesis that batteries are fully discharged after two hours of the event.

FIGURE 4-8: PG&E SUBGROUP A.4 VPP EVENT DAY DISPATCH BEHAVIORS

[redacted]

Additionally, ELRP event participation heavily influence the load shape prior to curtailment on consecutive event days. Figure 4-9 presents six event days, the top row consists of three consecutive event days where prior to that day there was another ELRP event day. The bottom row presents three event days where there is no prior ELRP event day. Rather than highlighting the event hours, this figure highlights the “Solar Window” (hours ending 9 through 17). On the consecutive days there is load increase (relative to the baseline) starting at hour ending 9 and lasting either a few hours or up until curtailment begins.

FIGURE 4-9: PG&E SUBGROUP A.4 VPP CONSECUTIVE EVENT DAY PRE-CHARGING BEHAVIOR

[redacted]

Notably, the pre-charging behavior does not occur on days where there is not a prior event. The probable cause is that the batteries are charging once solar PV becomes available and that their stored capacity was depleted in the prior days event activity. However, this cause is an educated guess and is not knowable without battery telemetry data including charge level.

Regardless of it cause, repeated event days appear to cause load increases in the hours leading up to curtailment. On its own, this behavior is not inherently problematic; however, this behavior paired with event curtailments not being tied to event start times can cause unintended load increases when ELRP resources are needed. Further, this effect adds to the dilution of average event hour impacts by adding load increases in ELRP event window.

4.4.2 Subgroup A.4 VPP Event Day Load Impacts

Now that A.4 event participation behaviors have been outlined, the average event hour impacts can be put into greater context. Table 4-12 presents the event day impacts for A.4 VPP. Given that impacts and baselines are derived from net load, and they cross positive and negative values of load, average percent load reduction are not intuitive and are excluded.

As anticipated, the event days with the largest impacts are one or two hours in duration without a prior event day. The event days with the largest impacts include September 1st and September 3rd with [redacted] and [redacted] MWh of load reduction in the average event hour in aggregate, respectively. The average event day load reduction is [redacted] MWh; however this average day is largely made up of days that are exclusively three hours or longer. As a result, the impacts on the average event day are a mix of curtailed load and load increasing behaviors.

TABLE 4-12: PG&E PY 2022 ELRP AVERAGE EVENT HOUR IMPACT – SUBGROUP A.4 VPP

Event Date	Event Window	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
8/17/2022	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8/31/2022	17:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/1/2022	18:00-19:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/3/2022	18:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/4/2022	17:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/5/2022	17:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/6/2022	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/7/2022	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/8/2022	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/9/2022	16:00-18:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Avg. Event	16:00-21:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

4.4.3 Subgroup A.4 Average Event Day Impacts by Domain

Table 4-13 and Table 4-14 present the average event day impacts by geographic domains and participant characteristics, respectively. As seen in Table 4-13 and Table 4-14, participants located in the Other LCA area and participants paired with solar PV provide the largest load reduction per capita and in aggregate.

TABLE 4-13: PG&E SUBGROUP A.4 VPP AVERAGE EVENT DAY IMPACTS BY GEOGRAPHY DOMAINS

Domain	Sub-Domain	Num. of Customers	Avg. Per Capita Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. Aggregate MW Impact Reduction (MWh/h)
All	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Climate Zone	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Local Capacity Area	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SubLAP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

TABLE 4-14: PG&E SUBGROUP A.4 VPP AVERAGE EVENT DAY IMPACTS BY PARTICIPANT CHARACTERISTICS

Domain	Sub-Domain	Num. of Customers	Avg. Per Capita Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. Aggregate MW Impact Reduction (MWh/h)
All	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Customer Type	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dually Enrolled	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NEM Status	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Technology Type	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

4.5 SUBGROUP A.6 RESIDENTIAL EVENT DAY IMPACTS

Residential A.6 participants represent the largest ELRP participant population with more than 1.5 million participants enrolled in the program in PY 2022. There are four enrollment pathways into the A.6 Residential subgroup. These include CARE auto-enrollment, FERA auto-enrollment, HER auto-enrollment and self-enrollment. Impacts are explored for each enrollment group and at the overall participant population level.

Figure 4-10 presents the average event day load shape for residential A.6 customers. The average event is presented using both net and delivered load. Unlike other ELRP subgroups, the average event day for A.6 Residential participants is the average of all event days as a result of a constant 4 pm to 9 pm event window. As seen, the average event impact is modest when examined visually. From a percentage of load perspective, the reduction is modest with an average hourly load reduction of 1.9% of delivered load and 2.0% of net load. However, the sheer volume of participants resulted in average event hourly reduction of 53.9 MWh in delivered and 57.0 MWh in net load.

Public Version. Confidential content removed and blacked out.

FIGURE 4-10: PG&E AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – SUBGROUP A.6 RESIDENTIAL

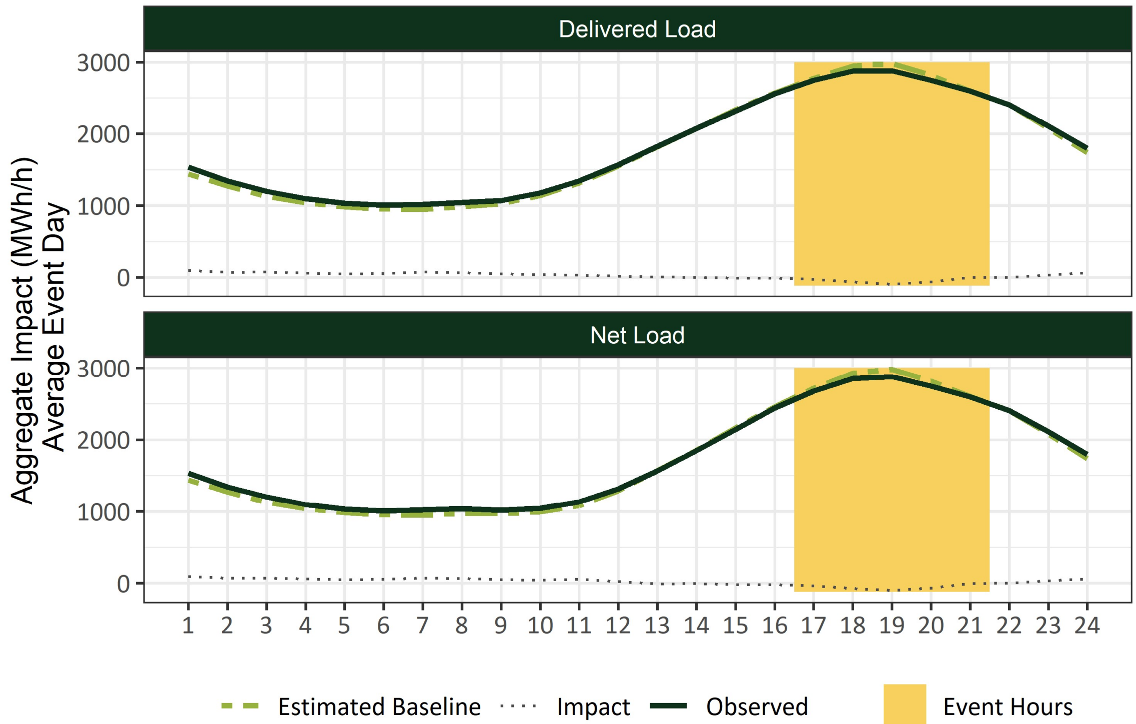


Table 4-15 and Table 4-16 present the event day average hourly load reduction for each A.6 Residential event and the average event day for delivered and net load respectively. As seen, load reductions as a percentage of load ranged from -1.3% to 5.5% of delivered load and -1.4 to 6.0% of net load, with the events with the largest load reductions occurring on August 17th and September 6th.

The evaluation team explored whether load reductions (per capita and in aggregate) were correlated with temperature, however, the ex post impacts did not find that PY 2022 events trended positively or negatively with temperature in a meaningful way. This is not too surprising given the behavioral nature of the ELRP and the quantity of auto-enrolled customers. However, the largest event day impacts were the very first ELRP event for A.6 and on September 6th, which coincided with Governor Gavin Newsom's request to curtail energy use to prevent black outs. It may be that participants are more likely to respond to an ELRP event notification if they feel a sense of urgency or necessity.

TABLE 4-15: PG&E PY 2022 ELRP AVERAGE EVENT HOUR IMPACT – SUBGROUP A.6 RESIDENTIAL – DELIVERED LOAD

Event Date	Event Window	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
8/17/2022	16:00-21:00	1,480,622	1.709	0.094	5.5%	139.2	85.0
9/1/2022	16:00-21:00	1,486,648	1.702	-0.022	-1.3%	-32.9	87.8
9/2/2022	16:00-21:00	1,486,940	1.708	0.035	2.0%	51.6	86.2
9/3/2022	16:00-21:00	1,487,016	1.674	0.047	2.8%	69.5	87.3
9/4/2022	16:00-21:00	1,487,135	1.876	0.052	2.8%	76.9	93.6
9/5/2022	16:00-21:00	1,487,934	2.161	0.037	1.7%	54.6	98.0
9/6/2022	16:00-21:00	1,509,296	2.213	0.057	2.6%	86.7	97.7
9/7/2022	16:00-21:00	1,509,335	2.039	0.040	1.9%	59.6	93.7
9/8/2022	16:00-21:00	1,509,436	2.039	-0.007	-0.4%	-11.1	95.1
9/9/2022	16:00-21:00	1,509,460	1.821	0.030	1.6%	45.1	88.2
Avg. Event	16:00-21:00	1,495,382	1.895	0.036	1.9%	53.9	91.3

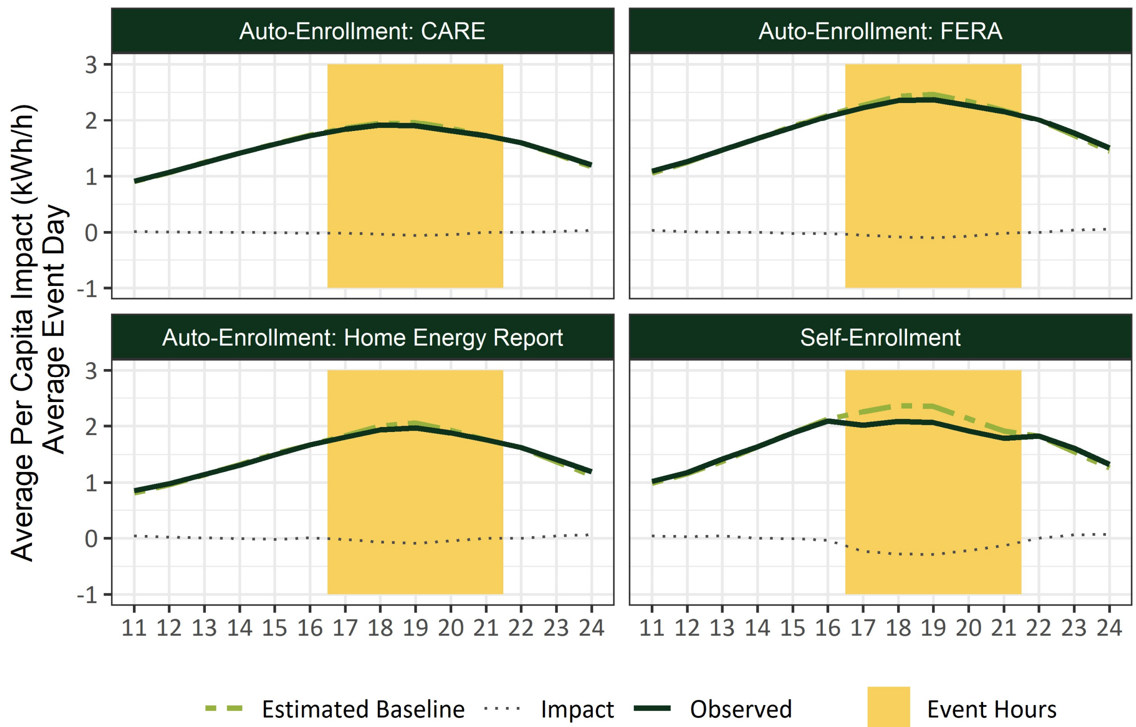
TABLE 4-16: PG&E PY 2022 ELRP AVERAGE EVENT HOUR IMPACT – SUBGROUP A.6 RESIDENTIAL – NET LOAD

Event Date	Event Window	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
8/17/2022	16:00-21:00	1,480,622	1.697	0.102	6.0%	151.6	85.0
9/1/2022	16:00-21:00	1,486,648	1.682	-0.023	-1.4%	-34.9	87.8
9/2/2022	16:00-21:00	1,486,940	1.690	0.035	2.1%	51.9	86.2
9/3/2022	16:00-21:00	1,487,016	1.654	0.045	2.7%	67.6	87.3
9/4/2022	16:00-21:00	1,487,135	1.860	0.052	2.8%	77.3	93.6
9/5/2022	16:00-21:00	1,487,934	2.153	0.040	1.8%	59.1	98.0
9/6/2022	16:00-21:00	1,509,296	2.208	0.062	2.8%	93.9	97.7
9/7/2022	16:00-21:00	1,509,335	2.030	0.042	2.1%	63.7	93.7
9/8/2022	16:00-21:00	1,509,436	2.030	-0.006	-0.3%	-8.6	95.1
9/9/2022	16:00-21:00	1,509,460	1.812	0.032	1.8%	48.2	88.2
Avg. Event	16:00-21:00	1,495,382	1.883	0.038	2.0%	57.0	91.3

4.5.1 Subgroup A.6 Residential Average Event Day Impacts by Enrollment Group

As mentioned previously, there are four enrollment pathways into the A.6 Residential; these include CARE auto-enrollment, FERA auto-enrollment, HER auto-enrollment and self-enrollment. Figure 4-11 below presents the average event day per capita load shapes by these enrollment groups for delivered load. Given that the difference between delivered and net load is visually imperceptible only delivered load is presented for brevity.

FIGURE 4-11: PG&E AVERAGE EVENT DAY PER CAPITA LOAD IMPACT BY A.6 RESIDNTIAL ENROLLMENT GROUP – DELIVERED LOAD



As seen in the figure above and in Table 4-17 below, the enrollment group that provides the greatest level of curtailment as a percentage of load is the self-enrolled participants population (10.4% of delivered load and 10.8% of net load). This is expected as these participants elected to participate in the ELRP and are fully aware of their participation.

In general, CARE participants provided the lowest level of curtailment with and hourly average of 1.6% of delivered load and 1.7% of net load but this subgroup makes up the largest share of A.6 Residential participants. Auto-enrolled FERA and HER participants provide relatively similar load reductions in terms of percent load reductions with 2.5% and 2.6% of load reductions in delivered load, respectively, and 2.8% and 2.7% of net load.

Although the auto-enrolled participant segments do not provide nearly as much reduction compared to the self-enrolled in terms of per capita load predictions, they do provide the largest share or aggregate impacts due the substantially higher volume of participants in these groups.

TABLE 4-17: PG&E SUBGROUP A.6 RESIDENTIAL AVERAGE EVENT DAY IMPACTS BY ENROLLMENT GROUP AND LOAD TYPE

Load Type	Enrollment Group	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
Delivered Load	Auto-Enrollment: CARE	1,053,744	1.872	0.030	1.6%	31.6	92.2
	Auto-Enrollment: FERA	29,790	2.346	0.062	2.6%	1.8	91.6
	Auto-Enrollment: HER	408,355	1.918	0.048	2.5%	19.7	88.7
	Self-Enrollment	3,494	2.239	0.233	10.4%	0.8	99.9
	All A.6	**1,495,382**	**1.895**	**0.036**	**1.9%**	**53.9**	**91.3**
Net Load	Auto-Enrollment: CARE	1,053,744	1.865	0.032	1.7%	33.5	92.2
	Auto-Enrollment: FERA	29,790	2.337	0.065	2.8%	1.9	91.6
	Auto-Enrollment: HER	408,355	1.892	0.051	2.7%	20.7	88.7
	Self-Enrollment	3,494	2.225	0.239	10.8%	0.8	99.9
	All A.6	**1,495,382**	**1.883**	**0.038**	**2.0%**	**57.0**	**91.3**

4.5.2 Subgroup A.6 Residential Flex Alert vs. ELRP Load Reduction Contributions

The matched control groups used for estimating load impacts allow for the determination of relative ELRP load reduction compared with Flex Alert impacts in the general population of residential non-ELRP participants. Since all ELRP A.6 Residential event days are Flex Alert days, it was anticipated that there would be load reduction associated with Flex Alerts and requests from the California State Government to curtail load. Given the impacts are small in terms of percent load reductions, incorporating Flex Alerts into modeling was required to account for similar load reductions in the non-participant population.

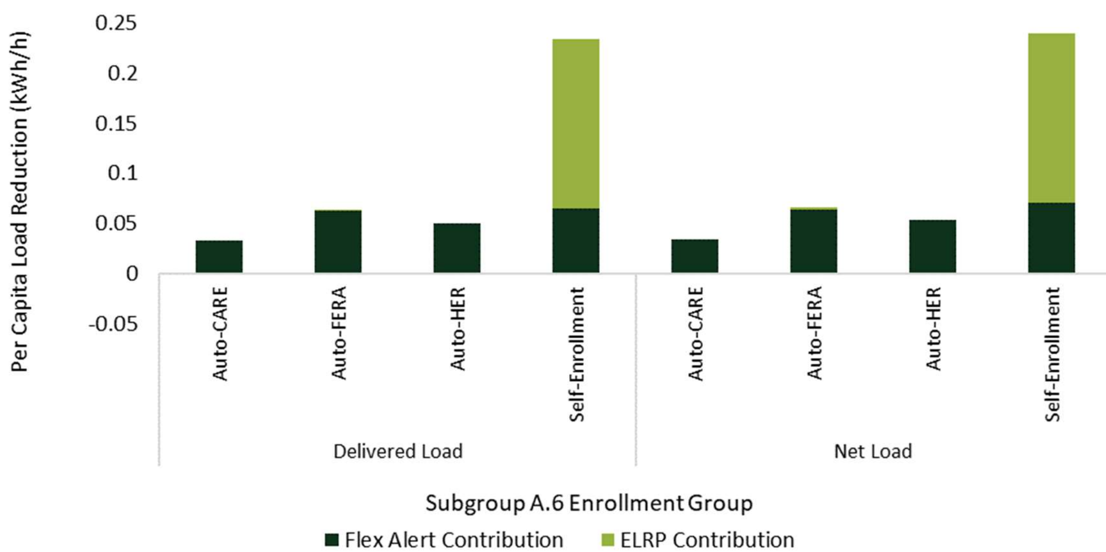
The goal of the ELRP is to compensate participation in Flex Alerts rather than provide incremental load reductions to Flex Alerts. As a result, the impacts associated to A.6 Residential are the combined effects of Flex Alerts and ELRP participation. Table 4-18 and Figure 4-12 present the relative contribution to overall reported impacts. As seen, ELRP contribution, relative to Flex Alerts, is virtually zero for the auto-enrolled subgroups. That is to say, relative to the general population's response to Flex Alerts, there is essentially no increase in load reductions as a result of auto-enrolling the entire population of CARE, FERA and HER customers into the ELRP.

TABLE 4-18: PG&E SUBGROUP A.6 RESIDENTIAL AVERAGE EVENT DAY PER CAPITA LOAD IMPACTS CONTRIBUTION - FLEX ALERT VS. ELRP

Load Type	Enrollment Group	Avg. Per Capita Flex Alert Impact Contribution (kWh/h)	Avg. Per Capita ELRP Impact Contribution (kWh/h)	Avg. Per Capita Combined Impact (A.6 Reported Impact) (kWh/h)
Delivered Load	Auto-Enrollment: CARE	0.033	-0.002	0.030
	Auto-Enrollment: FERA	0.062	0.001	0.062
	Auto-Enrollment: HER	0.050	-0.002	0.048
	Self-Enrollment	0.065	0.169	0.233
Net Load	Auto-Enrollment: CARE	0.034	-0.001	0.032
	Auto-Enrollment: FERA	0.064	0.002	0.065
	Auto-Enrollment: HER	0.053	-0.001	0.051
	Self-Enrollment	0.070	0.170	0.239

Note: Flex Alert and ELRP impact contributions may not sum to combined impacts due to rounding

FIGURE 4-12: PG&E SUBGROUP A.6 RESIDENTIAL AVERAGE EVENT DAY PER CAPITA LOAD IMPACTS CONTRIBUTION - FLEX ALERT VS. ELRP



The incremental impact of auto-enrolled participants, on average, ranges from -0.002 to 0.002 kWh depending on auto-enrollment group and load type. An important take-away from this finding is that load reductions associated with auto-enrolled customers would have happened regardless of the ELRP. An important caveat, however, is that auto-enrolled participants are matched with a control group that does not include CARE, FERA, or HER customers due to the lack non-ELRP customers in these groups.

Self-enrolled customers, however, do have incremental load reductions associated with ELRP participation. More than two-thirds of their combined impact is associated with ELRP event participation.

4.5.3 Subgroup A.6 Residential Average Event Day Impacts Dually Enrolled Customers

The residential A.6 subgroup also has a substantial number of dually enrolled SmartRate™ customers (roughly 22,000). The majority of the participants were auto-enrolled into the ELRP. As a result, it is important to understand the ILR contribution resulting from ELRP participation. Figure 4-13 presents the average event day load shape for residential A.6 customers. The average event is presented using both net and delivered load. All four A.6 enrollment groups have dually enrolled SmartRate™ participants, however, the self-enrolled SmartRate™ participants were not evaluated due to small participation counts.

Public Version. Confidential content removed and blacked out.

FIGURE 4-13: PG&E A.6 RESIDENTIAL AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – DUALLY ENROLLED SMARTRATE™

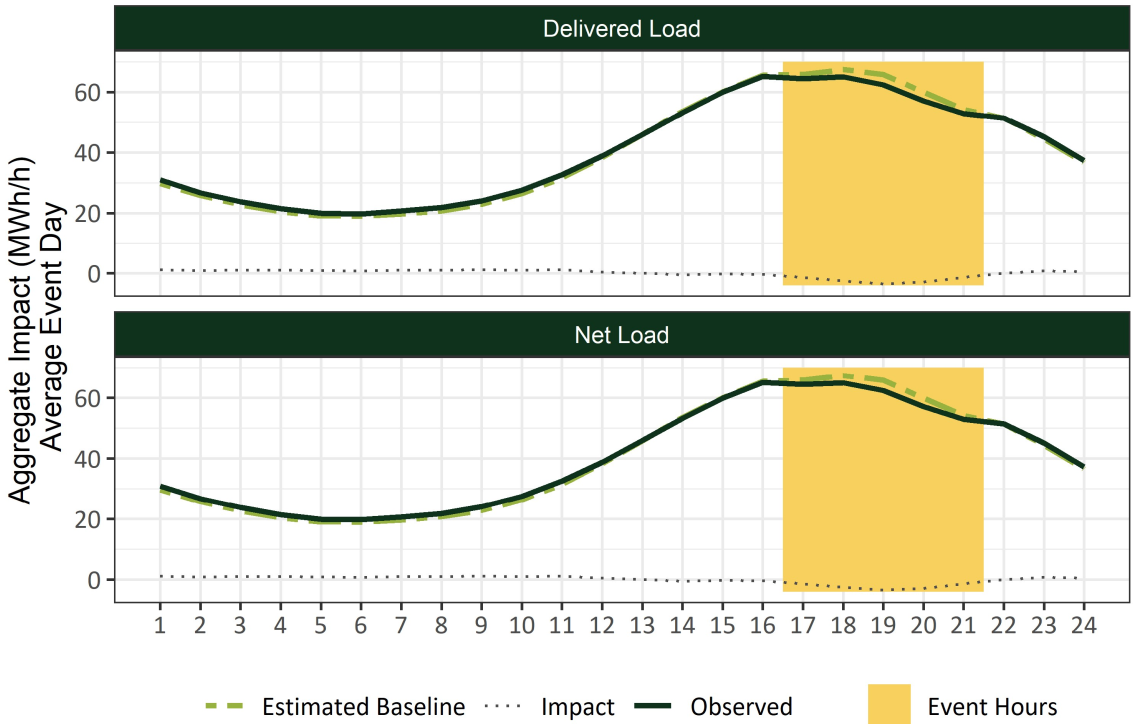


Table 4-19 below presents the average event day load ILR impacts for dually enrolled SmartRate™ customers. On average percent load reductions for these customers are greater than those in each of the non-dually enrolled segments with load decreases ranging between 3.4% and 3.8% depending on the enrollment group and load types. This suggests that dually enrolled A.6 Residential participants are more engaged with DR and the ELRP than the population of non-dually enrolled auto-enrolled participants.

Public Version. Confidential content removed and blacked out.

TABLE 4-19: PG&E SUBGROUP A.6 RESIDENTIAL AVERAGE EVENT DAY IMPACTS BY ENROLLMENT GROUP AND LOAD TYPE – DUALLY ENROLLED SMARTRATE™ PARTICPANTS

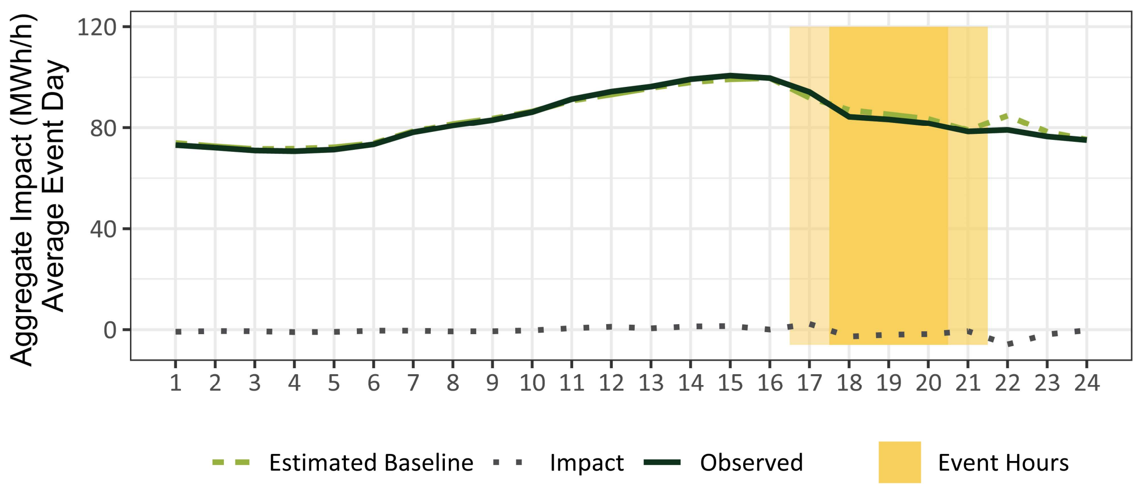
Load Type	Enrollment Group	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
Delivered Load	Auto-Enrollment: CARE	17,287	2.901	0.108	3.7%	1.9	101.3
	Auto-Enrollment: FERA	629	2.821	0.107	3.8%	0.1	100.2
	Auto-Enrollment: HER	4,007	2.624	0.090	3.4%	0.4	98.9
	Self-Enrollment*	--	--	--	--	--	--
	All A.6	**21,923**	**2.848**	**0.105**	**3.7%**	**2.3**	**100.8**
Net Load	Auto-Enrollment: CARE	17,287	2.901	0.108	3.7%	1.9	101.3
	Auto-Enrollment: FERA	629	2.821	0.107	3.8%	0.1	100.2
	Auto-Enrollment: HER	4,007	2.624	0.090	3.4%	0.4	98.9
	Self-Enrollment*	--	--	--	--	--	--
	All A.6	**21,923**	**2.848**	**0.105**	**3.7%**	**2.3**	**100.8**

*Note Evaluated

4.6 SUBGROUP B.2 CBP AGGREGATOR EVENT DAY IMPACTS

The PY 2022 ELRP saw 13 CBP aggregators participate in the ELRP through subgroup B.2. Due to the nature of this group, all participants are dually enrolled and impacts represent ILR to CBP participation. Figure 4-14 below presents the average event day load impact. As seen in the load shape and in Table 4-20, load reductions were generally small (1.1% of load) with an average per capita load reduction of 2.0 kWh.

FIGURE 4-14: PG&E AVERAGE EVENT DAY AGGREGATE LOAD IMPACT – SUBGROUP B.2 CBP AGGREGATOR



Despite the generally small load reductions, one event stands out with substantial ILR. September 1st provided an estimated 19.9% reduction in load reductions per hour. This is not typical of ELRP contributions which ranged from -1.4% to 3.9% on all other days. In general, B.2 Aggregators are less responsive to ELRP events on non-CBP days compared with dual program event days. A limitation of the analysis for this segment is the inability to account for participant level contributions to CBP market bids. Rather, the typical CBP response is captured to account for ILR to CBP.

TABLE 4-20: PG&E PY 2022 ELRP AVERAGE EVENT HOUR IMPACT – SUBGROUP B.2 CBP AGGREGATORS

Event Date	Event Window	Num. of Customers	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
8/31/2022*	16:00-21:00	514	200.9	6.7	3.4%	3.5	84.6
9/1/2022*	17:00-20:00	578	181.2	36.0	19.9%	20.8	89.5
9/3/2022	18:00-19:00	578	188.3	-2.6	-1.4%	-1.5	87.3
9/4/2022*	18:00-20:00	578	178.8	5.7	3.2%	3.3	94.7
9/5/2022	17:00-20:00	578	191.7	-3.4	-1.8%	-2.0	96.5
9/6/2022*	17:00-21:00	578	156.0	-3.7	-2.4%	-2.2	97.2
9/7/2022*	16:00-21:00	578	166.0	6.5	3.9%	3.8	93.8
9/8/2022*	16:00-21:00	578	165.5	1.9	1.2%	1.1	94.9
9/9/2022	16:00-21:00	578	207.1	6.9	3.4%	4.0	92.6
Avg. Event	16:00-18:00	567	175.7	2.0	1.1%	1.1	93.7

*Indicates a dual CBP and ELRP event day for all or a portion of B.2 CBP aggregators.

Subgroup B.2 CBP Aggregator Average Event Day Impacts by Subgroup

Table 4-21 and Table 4-22 present the average event day impacts by geographic domains and participant characteristics respectively.

Public Version. Confidential content removed and blacked out.

TABLE 4-21: PG&E SUBGROUP B.2 CBP AGGREGATOR AVERAGE EVENT DAY IMPACTS BY GEOGRAPHY DOMAINS

Domain	Sub-Domain	Num. of Customers	Avg. Per Capita Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. Aggregate MW Impact Reduction (MWh/h)
All	All	567	175.7	2.0	1.1%	1.1
Climate Zone	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2	42	125.1	4.1	3.2%	0.2
	3	103	112.1	-1.6	-1.4%	-0.2
	4	91	312.2	-1.3	-0.4%	-0.1
	5	19	137.0	12.0	8.7%	0.2
	11	32	99.1	4.6	4.6%	0.1
	12	114	176.8	-2.1	-1.2%	-0.2
	13	155	184.2	6.4	3.5%	1.0
Local Capacity Area	Greater Bay Area	224	192.7	-1.7	-0.9%	-0.4
	Greater Fresno Area	94	205.4	11.9	5.8%	1.1
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Kern	17	107.0	-6.8	-6.3%	-0.1
	North Coast and North Bay	38	127.8	4.3	3.4%	0.2
	Other	125	176.5	0.8	-1.7%	0.2
	Sierra	37	106.1	3.4	3.2%	0.1
	Stockton	22	363.9	-2.3	-0.6%	-0.1
SubLAP	SLAP_PGCC	40	152.0	-7.3	-4.8%	-0.3
	SLAP_PGEB	78	118.5	-2.9	-2.5%	-0.2
	SLAP_PGF1	95	207.7	11.7	5.6%	1.1
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SLAP_PGKN	19	99.6	-4.3	-4.3%	-0.1
	SLAP_PGNB	24	141.0	7.3	5.2%	0.2
	SLAP_PGNP	44	146.4	0.1	0.1%	0.0
	SLAP_PGP2	22	71.8	-1.6	-2.2%	0.0
	SLAP_PGSB	61	388.3	1.5	0.4%	0.1
	SLAP_PGSF	23	140.8	4.8	3.4%	0.1
	SLAP_PGSI	37	106.1	3.4	3.2%	0.1
	SLAP_PGST	21	356.2	-3.2	-0.9%	-0.1
	SLAP_PGZP	78	146.7	2.7	1.8%	0.2

Public Version. Confidential content removed and blacked out.

TABLE 4-22: PG&E SUBGROUP B.2 CBP AGGREGATOR AVERAGE EVENT DAY IMPACTS BY PARTCIPANT CHARACTERISTICS

Domain	Sub-Domain	Num. of Customers	Avg. Per Capita Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. Percent Load Reduction	Avg. Aggregate MW Impact Reduction (MWh/h)
All	All	567	175.7	2.0	1.1%	1.1
Customer Size	(0) UNDER 20KW	28	0.3	0.7	211.8%	0.0
	(1) 20KW TO 199.99 KW	379	56.0	1.4	2.5%	0.5
	(2) 200KW OR GREATER	160	490.8	3.6	0.7%	0.6
Customer Type	CCA (Comm Choice Aggregation)	236	179.5	1.1	0.6%	0.3
	DA (Direct Access)	161	183.0	1.5	0.8%	0.2
	FS (Full Service)	171	162.8	3.8	2.3%	0.6
Dually Enrolled	CBP	567	175.7	2.0	1.1%	1.1
NAICS Description	Agriculture, Mining & Construction	161	143.3	4.0	2.8%	0.7
	Institutional/Government	35	66.8	3.3	5.0%	0.1
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Other	125	176.5	0.8	-1.7%	0.2
	Retail Stores	308	95.9	-0.3	-0.3%	-0.1
	Wholesale, Transport, Other Utilities	38	220.3	-5.2	-2.3%	-0.2
NEM Status	NEM	50	155.1	1.0	0.7%	0.1
	Non-NEM	518	177.7	2.1	1.2%	1.1
Technology Type	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	None	511	140.1	1.7	1.2%	0.9
	Solar PV	34	445.5	9.9	2.2%	0.3
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Unknown Technology Type	19	68.7	-1.7	-2.5%	0.0

4.7 AVERAGE EVENT DAY AGGREGATE IMPACTS BY HOUR

Table 4-23 through Table 4-30 present the aggregate hourly load impacts for each ELRP subgroup's average event day as presented in the ex post table generator. The highlighted hours represent event hours.

VERDANT

Public Version. Confidential content removed and blacked out.

TABLE 4-23: PG&E PY 2022 AGGREGATE HOURLY LOAD IMPACTS FOR THE AVERAGE EVENT DAY – GROUP A.1 BIP

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

VERDANT

Public Version. Confidential content removed and blacked out.

TABLE 4-24: PG&E PY 2022 AGGREGATE HOURLY LOAD IMPACTS FOR THE AVERAGE EVENT DAY – GROUP A.1 GENERAL

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

TABLE 4-25: PG&E PY 2022 AGGREGATE HOURLY LOAD IMPACTS FOR THE AVERAGE EVENT DAY – GROUP A.2 BIP NET LOAD

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

Public Version. Confidential content removed and blacked out.

TABLE 4-26: PG&E PY 2022 AGGREGATE HOURLY LOAD IMPACTS FOR THE AVERAGE EVENT DAY – GROUP A.2 BIP DELIVERED LOAD

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

TABLE 4-27: PG&E PY 2022 AGGREGATE HOURLY LOAD IMPACTS FOR THE AVERAGE EVENT DAY – GROUP A.4 VPP

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

Public Version. Confidential content removed and blacked out.

TABLE 4-28: PG&E PY 2022 AGGREGATE HOURLY LOAD IMPACTS FOR THE AVERAGE EVENT DAY – GROUP A.6 RESIDENTIAL NET LOAD

Hour-Ending	Estimated Reference Load (MWh)	Observed Event Day Load (MWh)	Estimated Load Impact (MWh)	Average Temperature (deg F)	Uncertainty Adjusted Impact (MWh)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	1,438.8	1,532.8	-94.0	75.8	-115.4	-115.4	-94.0	-72.5	-72.5
2	1,273.0	1,341.8	-68.9	74.3	-87.4	-87.4	-68.9	-50.3	-50.3
3	1,128.3	1,200.5	-72.2	73.1	-89.3	-89.3	-72.2	-55.2	-55.2
4	1,039.2	1,097.0	-57.8	71.8	-73.5	-73.5	-57.8	-42.1	-42.1
5	984.6	1,032.5	-47.8	70.9	-63.1	-63.1	-47.8	-32.6	-32.6
6	952.2	1,005.5	-53.3	70.1	-66.7	-66.7	-53.3	-39.9	-39.9
7	946.9	1,018.9	-72.0	69.3	-85.5	-85.5	-72.0	-58.5	-58.5
8	973.9	1,038.3	-64.4	69.2	-79.2	-79.2	-64.4	-49.6	-49.6
9	966.4	1,016.6	-50.2	72.1	-67.1	-67.1	-50.2	-33.2	-33.2
10	996.6	1,040.7	-44.2	76.8	-63.4	-63.4	-44.2	-24.9	-24.9
11	1,081.3	1,135.4	-54.1	81.3	-74.8	-74.8	-54.1	-33.4	-33.4
12	1,288.8	1,313.4	-24.6	85.5	-45.7	-45.7	-24.6	-3.4	-3.4
13	1,571.5	1,564.7	6.8	89.1	-13.3	-13.3	6.8	27.0	27.0
14	1,853.6	1,848.4	5.2	92.0	-7.7	-7.7	5.2	18.2	18.2
15	2,162.0	2,140.7	21.3	94.1	6.0	6.0	21.3	36.6	36.6
16	2,459.0	2,441.4	17.6	95.5	-5.8	-5.8	17.6	40.9	40.9
17	2,713.3	2,678.4	35.0	95.8	9.9	9.9	35.0	60.0	60.0
18	2,925.4	2,850.3	75.1	94.9	49.5	49.5	75.1	100.8	100.8
19	2,980.7	2,878.3	102.3	92.6	77.5	77.5	102.3	127.2	127.2
20	2,817.2	2,747.7	69.5	88.7	46.5	46.5	69.5	92.5	92.5
21	2,599.4	2,596.4	2.9	84.3	-16.3	-16.3	2.9	22.2	22.2
22	2,406.7	2,406.7	0.0	81.3	0.0	0.0	0.0	0.0	0.0
23	2,075.9	2,108.0	-32.1	79.2	-49.9	-49.9	-32.1	-14.3	-14.3
24	1,736.9	1,797.2	-60.3	77.4	-79.5	-79.5	-60.3	-41.0	-41.0
By Period:	**Estimated Reference Load (MWh/h)**	**Observed Event Day Load (MWh/h)**	**Estimated Load Impact (MWh/h)**	**Average Temperature (Deg F)**	**Uncertainty Adjusted Impact (MWh/r)- Percentiles**				
					10th%ile	**30th%ile**	**50th%ile**	**70th%ile**	**90th%ile**
Daily	1,723.8	1,743.0	-19.2	81.5	n/a	n/a	n/a	n/a	n/a
Avg. Event Hour	2,807.2	2,750.2	57.0	91.3	33.4	33.4	57.0	80.5	80.5

TABLE 4-29: PG&E PY 2022 AGGREGATE HOURLY LOAD IMPACTS FOR THE AVERAGE EVENT DAY – GROUP A.6 RESIDENTIAL DELIVERED LOAD

Hour-Ending	Estimated Reference Load (MWh)	Observed Event Day Load (MWh)	Estimated Load Impact (MWh)	Average Temperature (deg F)	Uncertainty Adjusted Impact (MWh)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	1,438.8	1,532.8	-94.0	75.8	-115.4	-115.4	-94.0	-72.5	-72.5
2	1,273.0	1,341.9	-68.9	74.3	-87.4	-87.4	-68.9	-50.3	-50.3
3	1,128.3	1,200.5	-72.2	73.1	-89.3	-89.3	-72.2	-55.2	-55.2
4	1,039.2	1,097.1	-57.8	71.8	-73.5	-73.5	-57.8	-42.1	-42.1
5	984.7	1,032.5	-47.8	70.9	-63.1	-63.1	-47.8	-32.6	-32.6
6	952.2	1,005.5	-53.3	70.1	-66.8	-66.8	-53.3	-39.9	-39.9
7	947.4	1,018.9	-71.5	69.3	-84.9	-84.9	-71.5	-58.0	-58.0
8	983.1	1,045.2	-62.1	69.2	-76.6	-76.6	-62.1	-47.6	-47.6
9	1,025.9	1,071.4	-45.5	72.1	-60.9	-60.9	-45.5	-30.1	-30.1
10	1,142.1	1,177.2	-35.1	76.8	-51.1	-51.1	-35.1	-19.0	-19.0
11	1,314.9	1,345.3	-30.4	81.3	-46.9	-46.9	-30.4	-14.0	-14.0
12	1,553.1	1,565.4	-12.3	85.5	-28.2	-28.2	-12.3	3.5	3.5
13	1,820.1	1,821.1	-1.0	89.1	-16.0	-16.0	-1.0	14.0	14.0
14	2,077.0	2,074.5	2.5	92.0	-10.1	-10.1	2.5	15.0	15.0
15	2,334.1	2,318.5	15.7	94.1	1.4	1.4	15.7	29.9	29.9
16	2,572.4	2,561.1	11.3	95.5	-8.5	-8.5	11.3	31.1	31.1
17	2,776.2	2,747.0	29.2	95.8	7.1	7.1	29.2	51.4	51.4
18	2,945.7	2,877.2	68.5	94.9	44.4	44.4	68.5	92.5	92.5
19	2,982.5	2,882.5	100.0	92.6	75.6	75.6	100.0	124.5	124.5
20	2,816.8	2,747.8	69.0	88.7	46.0	46.0	69.0	92.0	92.0
21	2,599.4	2,596.5	2.9	84.3	-16.3	-16.3	2.9	22.2	22.2
22	2,406.7	2,406.7	0.0	81.3	-0.2	-0.2	0.0	0.1	0.1
23	2,075.9	2,108.0	-32.1	79.2	-49.9	-49.9	-32.1	-14.3	-14.3
24	1,736.9	1,797.2	-60.3	77.4	-79.5	-79.5	-60.3	-41.0	-41.0
By Period:	Estimated Reference Load (MWh/h)	Observed Event Day Load (MWh/h)	Estimated Load Impact (MWh/h)	Average Temperature (Deg F)	Uncertainty Adjusted Impact (MWh/r)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
Daily	1,788.6	1,807.2	-18.6	81.5	n/a	n/a	n/a	n/a	n/a
Avg. Event Hour	2,824.1	2,770.2	53.9	91.3	31.4	31.4	53.9	76.5	76.5

Public Version. Confidential content removed and blacked out.

TABLE 4-30: PG&E PY 2022 AGGREGATE HOURLY LOAD IMPACTS FOR THE AVERAGE EVENT DAY – GROUP B.2 CBP AGGREGATOR

Hour-Ending	Estimated Reference Load (MWh)	Observed Event Day Load (MWh)	Estimated Load Impact (MWh/h)	Average Temperature (Deg F)	Uncertainty Adjusted Impact (MWh)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	86.3	85.3	1.0	77.0	0.9	1.0	1.0	1.0	1.0
2	84.7	84.1	0.6	75.0	0.6	0.6	0.6	0.6	0.6
3	83.5	82.8	0.7	73.7	0.7	0.7	0.7	0.7	0.7
4	83.6	82.5	1.1	72.3	1.1	1.1	1.1	1.1	1.1
5	84.3	83.2	1.0	71.4	1.0	1.0	1.0	1.1	1.1
6	86.1	85.7	0.5	70.5	0.5	0.5	0.5	0.5	0.5
7	91.7	91.2	0.5	69.9	0.4	0.4	0.5	0.5	0.5
8	95.2	94.4	0.8	69.9	0.8	0.8	0.8	0.8	0.8
9	97.7	97.0	0.7	73.2	0.7	0.7	0.7	0.7	0.7
10	101.0	100.7	0.3	78.2	0.3	0.3	0.3	0.3	0.3
11	106.0	106.7	-0.7	83.1	-0.7	-0.7	-0.7	-0.7	-0.7
12	108.8	110.1	-1.3	87.8	-1.4	-1.4	-1.3	-1.3	-1.3
13	111.8	112.5	-0.6	91.5	-0.6	-0.6	-0.6	-0.6	-0.6
14	114.4	115.8	-1.5	94.6	-1.5	-1.5	-1.5	-1.4	-1.4
15	115.8	117.5	-1.7	96.7	-1.7	-1.7	-1.7	-1.7	-1.7
16	116.3	116.3	0.0	98.2	-0.1	-0.1	0.0	0.0	0.0
17	107.3	110.0	-2.6	98.5	-2.7	-2.7	-2.6	-2.6	-2.6
18	101.7	98.5	3.2	97.5	3.1	3.2	3.2	3.2	3.2
19	99.6	97.3	2.3	95.1	2.3	2.3	2.3	2.3	2.3
20	97.5	95.5	2.1	91.0	2.0	2.0	2.1	2.1	2.1
21	92.3	91.6	0.7	86.4	0.7	0.7	0.7	0.7	0.7
22	99.1	92.3	6.8	83.4	6.7	6.7	6.8	6.8	6.8
23	91.4	89.3	2.2	81.2	2.1	2.2	2.2	2.2	2.2
24	87.8	87.6	0.3	79.3	0.2	0.3	0.3	0.3	0.3
By Period:	Estimated Reference Load (MWh/h)	Observed Event Day Load (MWh/h)	Estimated Load Impact (MWh/h)	Average Temperature (Deg F)	Uncertainty Adjusted Impact (MWh/h)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
Daily	97.7	97.0	0.7	83.1	n/a	n/a	n/a	n/a	n/a
Average Event Hour	99.7	98.6	1.1	93.7	1.1	1.1	1.1	1.1	1.1

4.8 ELRP NOMINATIONS VS EX POST IMPACTS

ELRP participants provide stated levels of nominated load reductions when enrolling into the program. For PG&E's Group A.1 BIP and A.1 General participants, Figure 4-15 and Figure 4-16 provide a comparison of the nominated load reductions along with the estimated ex post impacts for each event day.

FIGURE 4-15: PG&E PY 2022 GROUP A.1 BIP NOMINATIONS VS. EX POST IMPACTS

[redacted]

FIGURE 4-16: PG&E PY 2022 GROUP A.1 GENERAL NOMINATIONS VS. EX POST IMPACTS

[redacted]

While demand response evaluations do not typically explore realization rates, the ELRP evaluation explored the realization of nominations for Group A.1 customers to highlight the differences between stated and realized load reductions. The ELRP does not currently have a mechanism that holds participants to their stated nominations. As a result, understanding the realization rates may help inform expectations for future load reductions. The nomination realization rates were calculated for ELRP events as the ex post evaluated MW divided by the nominated MW. This results in a value that represents the share of nominations achieved for each event. A value of 100% indicates that all the nominations were achieved during a given event, above 100% indicates an event that exceeded nominations and below 100% represents an event day where nominations were not achieved. The nominations' realization rate for events are presented in Table 4-31.

TABLE 4-31 PG&E GROUP A.1 NOMINATION REALIZATION RATES BY EVENT

	Event Date								
Subgroup	**8/31/22**	**9/1/22**	**9/3/22**	**9/4/22**	**9/5/22**	**9/6/22**	**9/7/22**	**9/8/22**	**9/9/22**
A.1 BIP	0%	0%	5%	12%	11%	33%	37%	40%	34%
A.1 General	2%	4%	2%	4%	4%	5%	9%	7%	10%

5 EX ANTE IMPACTS

This section presents results from the ex ante impact analysis. The goal of the ex ante impact analysis is to estimate program impacts for future years under varying 1-in-10 and 1-in-2 weather scenarios across the ELRP event window (4:00 pm to 9:00 pm).[14] Given that the ELRP is a pilot program, the ex ante analysis seeks to provide ex ante estimates for program years 2023 through 2025. The ex ante analysis only seeks to estimate impacts for subgroups that actively participated in events in PY 2022. There was no event participation for Groups A.3 and A.5 for PG&E. As a result, there are no ex post impacts to inform a LIP-based ex ante analysis.

Ex ante impacts are estimated in two ways. These include program level ex ante impacts and the portfolio adjusted ex ante impacts. The program level ex ante impacts represent forecasted program impacts on ELRP-only event days and only include impacts from the ex post analysis in which there is no other DR participation on that day for dually enrolled participants. Conversely, portfolio adjusted ex ante impacts represent ex ante impacts that are incremental to the entire portfolio of PG&E's DR programs and represent ILR impacts. Compensation structures differ for dually enrolled participants and there is no mechanism or penalty structure that ensures reliable participation in ELRP. As a result, there are cases where the portfolio adjusted impacts are larger than the program level impacts. An example of this scenario is for BIP dually enrolled participants, who are only compensated for ILR during overlapping BIP event hours and are not compensated on ELRP-only event days. As a result load impacts are larger on dual program days (portfolio level) than on days in which there is only an ELRP event.

5.1 PG&E EX ANTE IMPACTS A.1 BIP

Figure 5-1 presents the portfolio adjusted and program level ex ante per capita impact load shape for a Utility 1-in-2 Typical Event Day for subgroup A.1 BIP participants. The portfolio adjusted impacts (left in the figure) are derived from the average per participant achievement beyond BIP FSLs observed in PY 2022 and are non-weather adjusted. Additionally, the first two hours of the RA window (hours ending 17 and 18) do not include any load reductions as there were no overlapping ELRP BIP and ELRP events in those hours in 2022.

Conversely, the program ex ante impacts (right in the figure) represent the forecasted load reductions on day that are exclusively ELRP event days only. The program specific impacts contain weather adjusted impacts and account for ELRP event fatigue over the event window.

---

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

Public Version. Confidential content removed and blacked out.

FIGURE 5-1: PG&E PORTFOLIO AND PROGRAM UTILITY 1-IN-2 TYPICAL EVENT DAY PER CAPITA LOAD SHAPE – SUBGROUP A.1 BIP

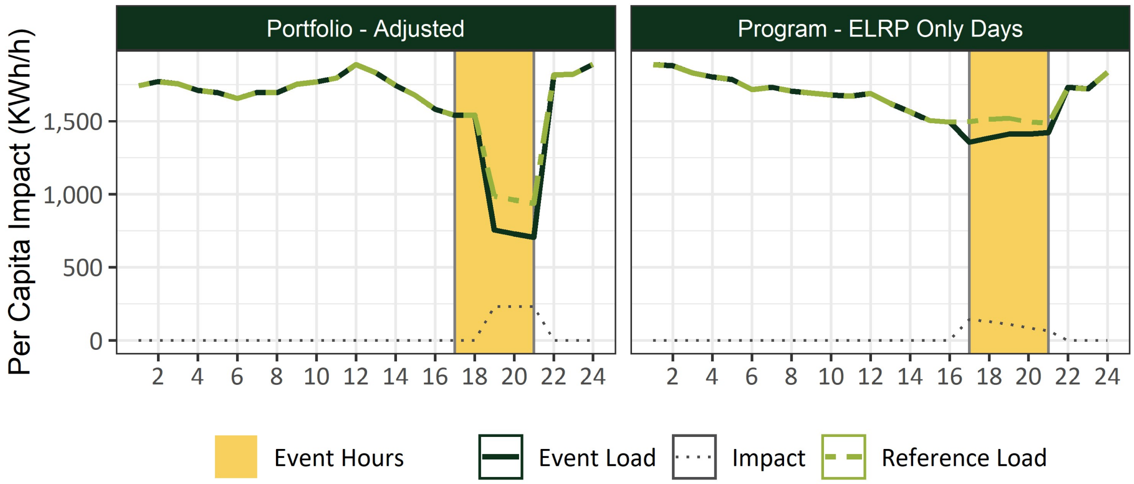


Table 5-1 below presents the portfolio adjusted and program level per capita and aggregate ex ante impacts for the PY 2023 monthly system peak and the typical event day. The portfolio adjusted impacts are larger than the program level (ELRP-only day) ex ante impacts. This is not surprising given that BIP participants are only compensated for load reductions on overlapping BIP event hours. It is to be expected that BIP customers may be more enticed to participate in the ELRP on BIP event days than on days in which they are not compensated. For the Utility 1-in-2 typical event day, the ex ante impacts associated with ILR are 1.4 MWh and 1.1 MWh for portfolio adjusted and program specific impacts respectively.

TABLE 5-1: PY 2023 PORTFOLIO AND PROGRAM UTILITY 1-IN-2 EX ANTE IMPACTS – SUBGROUP A.1 BIP

			Portfolio Adjusted			Program Level		
Day Type	Month	Num. of Parts.	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)
Monthly System Peak	May	10	1,186.0	138.5	1.4	1,401.7	79.7	0.8
	June	10	1,127.9	138.5	1.4	1,384.2	116.1	1.2
	July	10	1,154.4	138.5	1.4	1,411.8	93.5	0.9
	August	10	1,179.1	138.5	1.4	1,467.4	79.7	0.8
	September	10	1,214.3	138.5	1.4	1,522.5	136.5	1.4
	October	10	1,219.3	138.5	1.4	1,456.2	91.6	0.9
Typical Event Day	August	10	1,193.7	138.5	1.4	1,501.4	106.5	1.1

5.2 PG&E EX ANTE IMPACTS A.1 GENERAL

Figure 5-2 presents the portfolio adjusted and program level ex ante per capita impact load shape for a Utility 1-in-2 Typical Event Day for subgroup A.1 General participants. Given that most participants are non-dually enrolled (only enrolled in the ELRP), there is not a substantial difference between portfolio adjusted and program level ex ante impacts as detailed in Table 5-2. Both the portfolio adjusted, and program specific ex ante impacts are weather adjusted and account for participant fatigue.

FIGURE 5-2: PG&E PORTFOLIO AND PROGRAM UTILITY 1-IN-2 TYPICAL EVENT DAY PER CAPITA LOAD SHAPE – SUBGROUP A.1 GENERAL

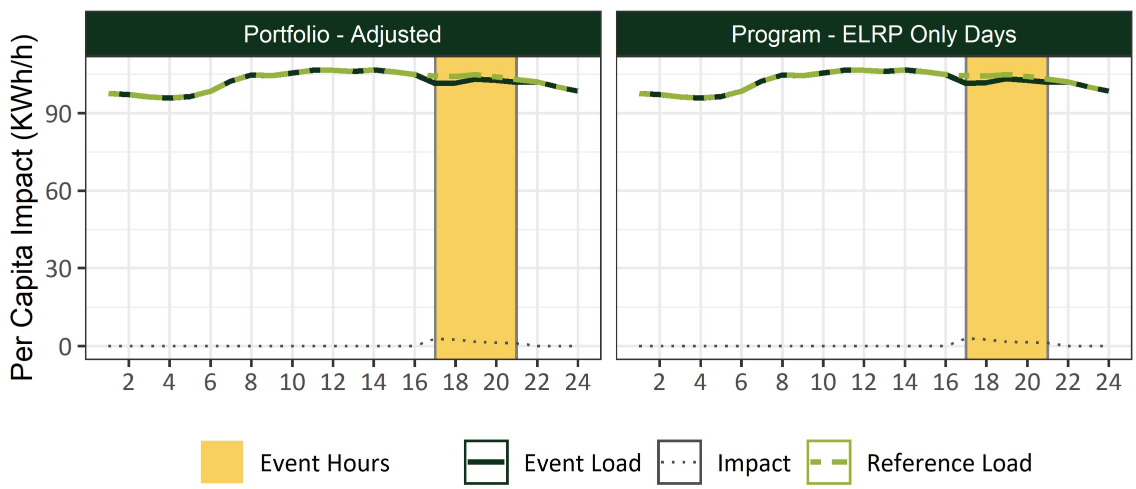


Table 5-2 below presents the portfolio adjusted and program level per capita and aggregate ex ante impacts for the PY 2023 monthly system peak and the typical event day. The PY 2022 events were extremely hot and the temperatures in those events more closely align with 1-in-10 weather scenarios given the weather normalization of impacts. The 1-in-2 tend to be smaller than the PY 2022 average event day impacts for A.1 General participants for this reason. For the Utility 1-in-2 typical event day, the ex ante impacts associated with ILR are 13.3 MWh and 13.6 MWh for portfolio adjusted and program specific impacts respectively.

TABLE 5-2: PY 2023 PORTFOLIO AND PROGRAM UTILITY 1-IN-2 TYPICAL EVENT DAY EX ANTE IMPACTS – SUBGROUP A.1 GENERAL

			Portfolio Adjusted			Program Level		
Day Type	Month	Num. of Parts.	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)
Monthly System Peak	May	7,023	101.6	1.6	11.0	101.7	1.6	11.3
	June	7,021	103.4	2.1	14.9	103.5	2.1	15.1
	July	7,017	102.8	1.9	13.4	102.9	1.9	13.6
	August	7,010	103.2	1.7	12.2	103.3	1.8	12.4
	September	7,008	105.3	3.2	22.5	105.4	3.3	22.9
	October	7,005	102.6	1.8	12.3	102.7	1.8	12.9
Typical Event Day	August	7,010	104.0	1.9	13.3	104.1	1.9	13.6

*Average per capita impacts may not multiply to aggregate impacts due to rounding

There are PDP customers included in the A.1 General participant forecasts. As a result, it is worth discussing their ex ante impacts separately. Figure 5-3 presents the portfolio adjusted and program specific ELRP impacts for subgroup A.1 General participants who are dually enrolled in PDP. As a seen in these figures, there are modest incremental load reductions in both ex ante types but they are slightly larger for program level ex ante impacts. This is the result of impacts being incremental to PDP on dual event days in the portfolio adjusted ex ante impacts.

FIGURE 5-3: PG&E PORTFOLIO AND PROGRAM UTILITY 1-IN-2 TYPICAL EVENT DAY PER CAPITA LOAD SHAPE – SUBGROUP A.1 GENERAL - PDP DUALLY ENROLLED

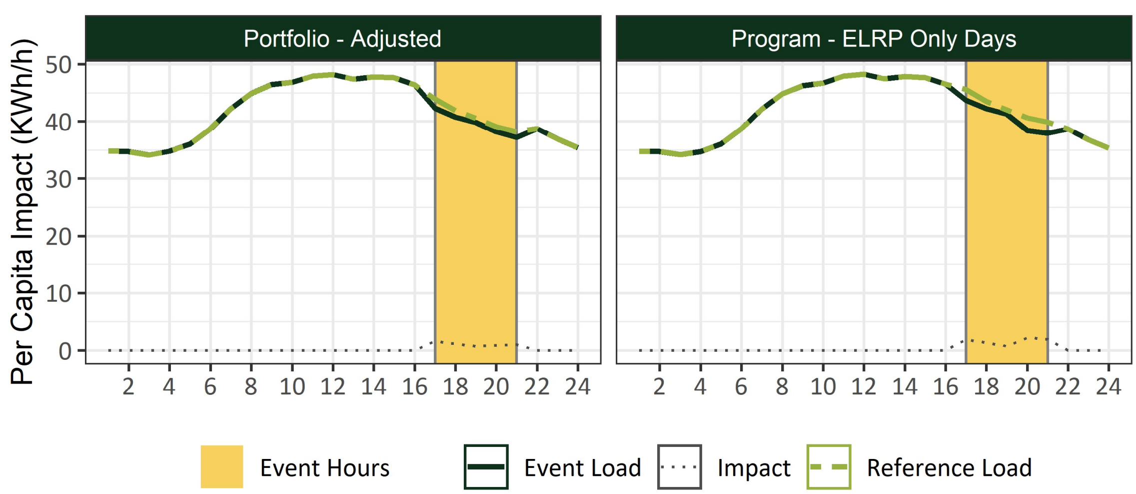


Table 5-3 presents the portfolio adjusted and program level per capita and aggregate ex ante impacts for PY 2023 monthly system peak and the typical event day. The program level ex ante impacts are slightly larger than the impacts associated with the portfolio (1.1 kWh per capita for the portfolio adjusted versus 1.6 kWh per capita in the program level ex ante). The PDP participant counts are only a portion of the ex ante participant, however, they result in the modest differences between the portfolio and program level ex ante impacts in the overall A.1 General forecasts.

TABLE 5-3: PY 2023 PORTFOLIO AND PROGRAM UTILITY 1-IN-2 TYPICAL EVENT DAY EX ANTE IMPACTS – SUBGROUP A.1 GENERAL - PDP DUALLY ENROLLED

			Portfolio Adjusted			Program Level		
Day Type	Month	Num. of Parts.	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)
Monthly System Peak	May	429	40.5	1.1	0.5	42.2	1.8	0.8
	June	427	42.1	1.2	0.5	43.7	1.6	0.7
	July	423	42.7	1.1	0.5	44.3	1.5	0.6
	August	416	40.6	1.0	0.4	42.2	1.5	0.6
	September	414	39.2	1.2	0.5	40.9	2.0	0.8
	October	411	37.2	1.3	0.5	38.9	2.7	1.1
Typical Event Day	August	416	40.7	1.1	0.4	42.3	1.6	0.7

5.3 PG&E EX ANTE IMPACTS A.2 BIP

Figure 5-4 presents the portfolio adjusted and program level ex ante per capita impact load shape for a Utility 1-in-2 Typical Event Day for subgroup A.2 BIP participants based on delivered load. A.2 BIP Ex Ante results based on net load are presented in the table generators. As with A.1 BIP, the portfolio adjusted impacts are derived from the average per participant achievement beyond BIP FSL commitments observed in PY 2022 and are non-weather adjusted. Additionally, the first two hours of the RA window (hours ending 17 and 18) do not include any load reductions as there were no overlapping ELRP BIP and ELRP events in those hours in 2022.

Conversely, the program ex ante impacts represent the forecasted load reductions on ELRP-only event days. The program-specific impacts contain weather adjusted impacts and account for ELRP event fatigue over the event window.

FIGURE 5-4: PG&E PORTFOLIO AND PROGRAM UTILITY 1-IN-2 TYPICAL EVENT DAY PER CAPITA LOAD SHAPE – SUBGROUP A.2 BIP - DELIVERED LOAD

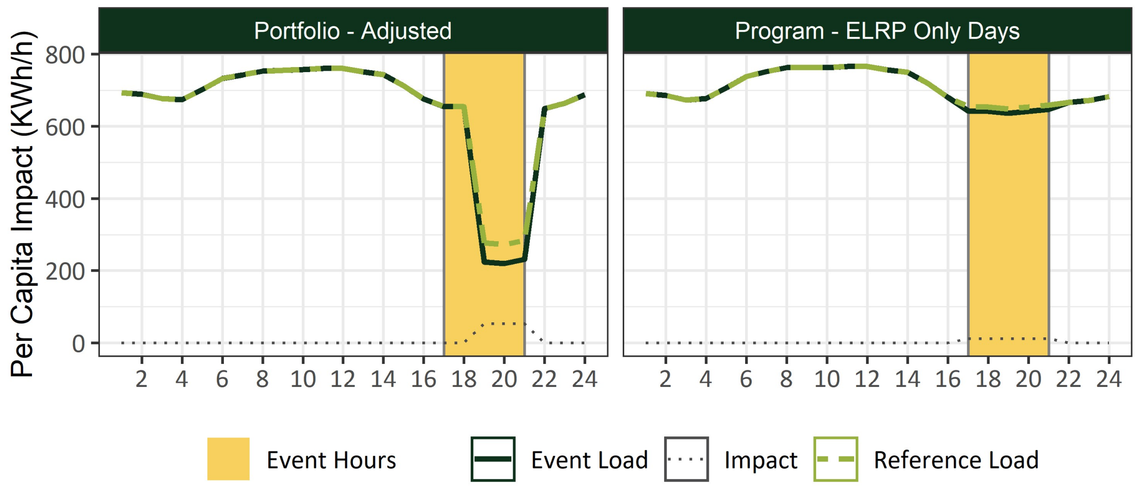


Table 5-4 below presents the portfolio adjusted and program level per capita and aggregate ex ante impacts for the PY 2023 monthly system peak and the typical event day. As with A.1 BIP, A.2 BIP portfolio adjusted impacts are greater than the program level (ELRP only event) ex ante impacts. This is not surprising given that BIP participants are only compensated for load reductions on overlapping BIP event hours. It is to be expected that BIP customers may be more enticed to participate in the ELRP on BIP event days than on days in which they are not compensated. For the Utility 1-in-2 typical event day, the ex ante impacts associated with ILR are 1.6 MWh and 1.3 MWh for portfolio adjusted and program specific impacts respectively.

TABLE 5-4: PY 2023 PORTFOLIO AND PROGRAM UTILITY 1-IN-2 EX ANTE IMPACTS – SUBGROUP A.2 BIP – DELIVERED LOAD

			Portfolio Adjusted			Program Level		
Day Type	Month	Num. of Parts.	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)
Monthly System Peak	May	111	453.5	32.0	3.6	670.3	11.9	1.3
	June	111	455.2	32.0	3.6	663.1	11.9	1.3
	July	111	447.7	32.0	3.6	647.5	11.9	1.3
	August	111	429.4	32.0	3.6	633.7	11.9	1.3
	September	111	415.9	32.0	3.6	647.4	12.3	1.4
	October	111	426.5	32.3	3.6	647.5	11.9	1.3
Typical Event Day	August	111	429.2	32.0	3.6	670.3	11.9	1.3

5.4 PG&E EX ANTE IMPACTS A.4 VPP

Figure 5-5 presents the portfolio adjusted and program level ex ante impacts for subgroup A.4 VPP participants. Unlike other ELRP subgroups, there are load increases prior to event curtailment and impacts are only assumed for two hours of the RA window (hours ending 19 and 20). This is done to capture the typical event response and incorporate event day pre-charging and dispatch behaviors discussed in section 4.4.1. Additionally, there is no dual enrollment in the ex ante participant forecasts for subgroup A.4. As a result, the portfolio adjusted and program level ex ante impacts are identical.

FIGURE 5-5: PG&E PORTFOLIO AND PROGRAM UTILITY 1-IN-2 TYPICAL EVENT DAY PER CAPITA LOAD SHAPE – SUBGROUP A.4 VPP

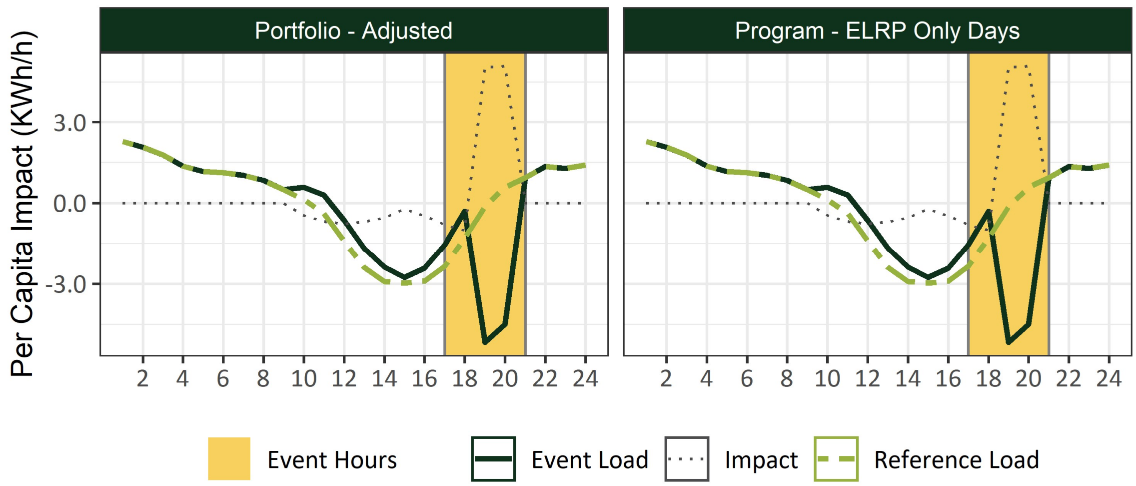


Table 5-5 below presents the portfolio adjusted and program level per capita and aggregate ex ante impacts for the PY 2023 monthly system peak and the typical event day. The portfolio adjusted and program level ex ante impacts are identical due to the absence of dual participation in A.4 VPP. The Utility 1-in-2 typical event day ex ante impacts are 7.1 MWh in aggregate for portfolio adjusted and program specific ex ante.

TABLE 5-5: PY 2023 PORTFOLIO AND PROGRAM UTILITY 1-IN-2 TYPICAL EVENT DAY EX ANTE IMPACTS – SUBGROUP A.4 VPP

			Portfolio Adjusted			Program Level		
Day Type	Month	Num. of Parts.	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)
Monthly System Peak	May	4,292	-0.7	1.7	7.2	-0.7	1.7	7.2
	June	4,292	-0.6	1.7	7.1	-0.6	1.7	7.1
	July	4,292	-0.7	1.7	7.2	-0.7	1.7	7.2
	August	4,292	-0.5	1.7	7.2	-0.5	1.7	7.2
	September	4,292	0.1	1.6	7.1	0.1	1.6	7.1
	October	4,292	0.5	1.7	7.2	0.5	1.7	7.2
Typical Event Day	August	4,292	-0.5	1.7	7.1	-0.5	1.7	7.1

5.5 PG&E EX ANTE IMPACTS A.6 RESIDENTIAL

Figure 5-6 presents the portfolio adjusted and program level ex ante per capita impact load shape for a Utility 1-in-2 Typical Event Day for subgroup A.6 Residential participants based on delivered and net load. Given that most participants are non-dually enrolled (only enrolled in the ELRP), there is not a substantial difference between portfolio adjusted and program level ex ante impacts as detailed in Table 5-6. Both the portfolio adjusted, and program specific ex ante impacts are weather adjusted and account for participant fatigue.

FIGURE 5-6: PG&E PORTFOLIO AND PROGRAM UTILITY 1-IN-2 TYPICAL EVENT DAY PER CAPITA LOAD SHAPE – SUBGROUP A.6 RESIDENTIAL

Table 5-6 below presents the portfolio adjusted and program level per capita and aggregate ex ante impacts for the PY 2023 monthly system peak and the typical event day. For the Utility 1-in-2 typical event day, the ex ante impacts associated with ILR are 44.8 MWh and 52.8 MWh for portfolio adjusted and program specific impacts respectively.

TABLE 5-6: PY 2023 PORTFOLIO AND PROGRAM UTILITY 1-IN-2 TYPICAL EVENT DAY EX ANTE IMPACTS – SUBGROUP A.6 RESIDENTIAL

			Portfolio Adjusted			Program Level		
Day Type	Month	Num. of Parts.	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)
System Peak	May	1,710,282	1.73	0.05	84.7	1.74	0.06	97.8
	June	1,718,614	1.88	0.02	36.3	1.88	0.03	43.2
	July	1,726,947	1.85	0.03	46.2	1.86	0.03	52.3
	August	1,735,279	1.81	0.03	49.4	1.81	0.03	56.7
	September	1,743,611	1.69	0.03	46.4	1.7	0.03	58.3
	October	1,751,948	1.50	0.07	116.1	1.51	0.08	140.9
Typical Event Day	August	1,735,279	1.82	0.03	44.8	1.83	0.03	52.8

Figure 5-7 presents the portfolio adjusted ex ante per capita impact load shape for a Utility 1-in-2 Typical Event Day for subgroup A.6 Residential participants based on delivered load by enrollment status. These graphs clearly illustrate the substantially larger per capita impacts of the self-enrolled residential participants. Table 5-7 presents Utility 1-in-2 Typical Event Day portfolio adjusted and program level by enrollment group for A.6 Residential participants. Both the portfolio adjusted and the program level per capita impacts show larger impacts for self-enrolled participants while the auto enrolled customers have larger aggregate impacts due to their larger participant population.

FIGURE 5-7: PG&E PORTFOLIO ADJUSTED 1-IN-2 TYPICAL EVENT DAY PER CAPITA LOAD SHAPE – SUBGROUP A.6 RESIDENTIAL BY ENROLLMENT GROUP - DELIVERED LOAD

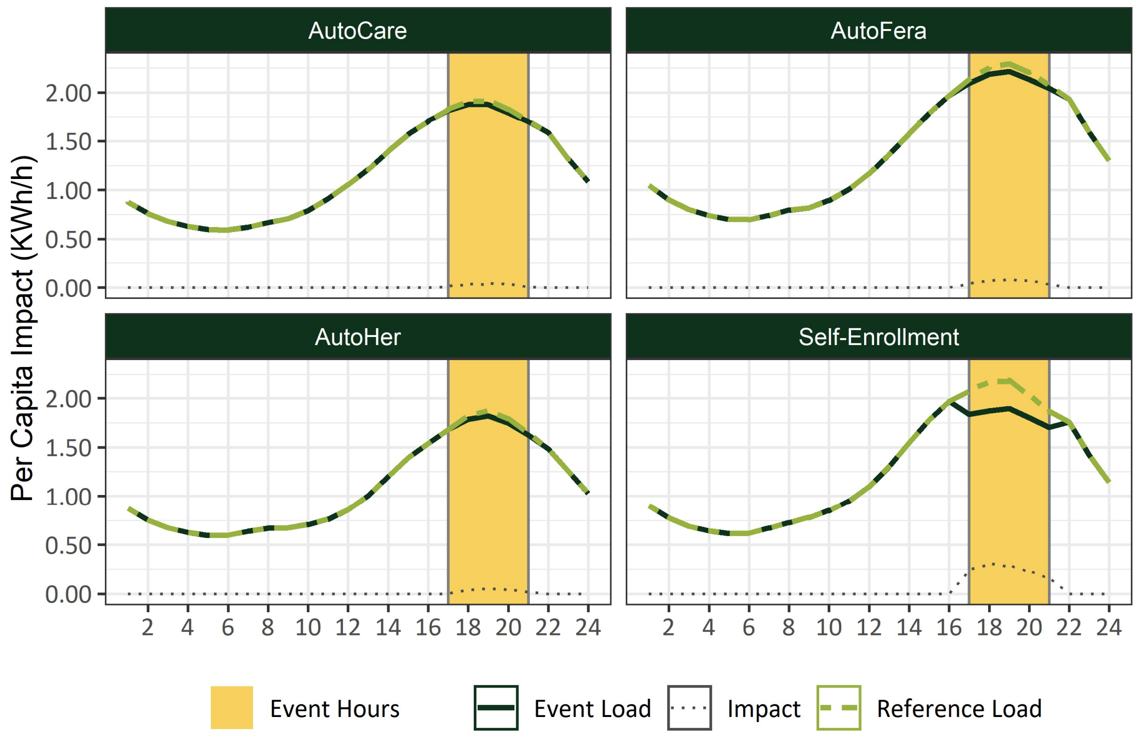


Table 5-7 presents the ex ante impacts under the Utility 1-in-2 weather scenario for the typical event day and august system peak. Unsurprisingly, the per capita ex ante impacts are largest for the self-enrolled customer segment. However the majority of MWh impacts are derived from the auto-enrolled CARE and HER participants as a result the significant number of participants in these segments.

Public Version. Confidential content removed and blacked out.

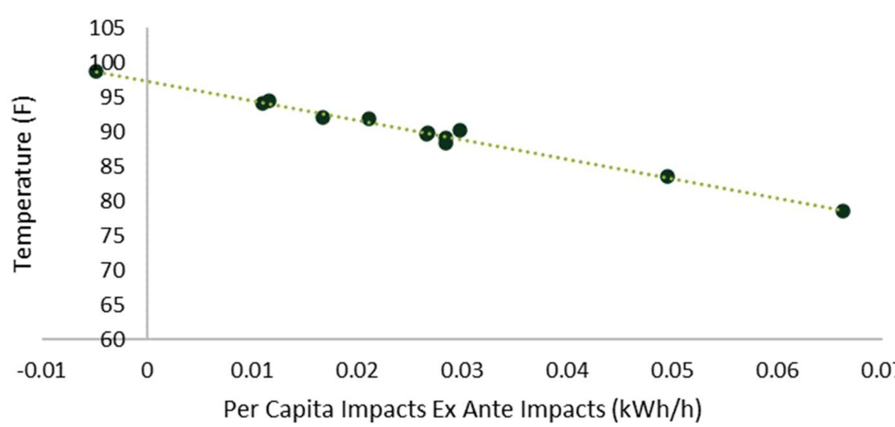
TABLE 5-7: PY 2023 PORTFOLIO AND PROGRAM UTILITY 1-IN-2 TYPICAL EVENT DAY AND AUGUST SYSTEM PEAK EX ANTE IMPACTS – SUBGROUP A.6 RESIDENTIAL BY ENROLLMENT GROUP

			Portfolio Adjusted			Program Level		
Enrollment Group	Day Type	Num. of Parts.	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)
Auto-CARE	August System Peak	1,215,439	1.83	0.03	30.4	1.84	0.03	37.4
Auto-FERA		35,945	2.18	0.06	2.0	2.18	0.06	2.0
Auto-HER		467,348	1.72	0.03	15.1	1.72	0.03	15.6
Self-Enrollment		16,546	2.10	0.23	3.8	2.11	0.24	4.0
Auto-CARE	Typical Event Day	1,215,439	1.83	0.02	26.6	1.84	0.03	34.2
Auto-FERA		35,945	2.19	0.06	2.1	2.19	0.06	2.1
Auto-HER		467,348	1.76	0.03	14.2	1.76	0.03	14.7
Self-Enrollment		16,546	2.06	0.24	3.9	2.07	0.25	4.1

5.5.1 A.6 Residential Ex Ante Impacts – Negative per capita Impact Correlation with Temperature

The ELRP is a behavioral DR program. Additionally, there are no penalties or direct load control that would help provide consistent event participation or load reductions. As a result, we see that ex ante impacts for A.6 Residential participants are negatively correlated with temperatures as described in Figure 5-8. This figure presents the utility system peak per capita impacts by temperature. Given the significant participant enrollment forecasts, this presents itself with a wide range of MWh forecasts depending on the weather scenario.

FIGURE 5-8: PG&E RESIDENTIAL A.6 UTILITY SYSTEM PEAK EX ANTE PER CAPITA IMPACTS BY TEMPERATURE



In the ex ante table generators and subsequent sections of this report, the A.6 1-in-2 impacts are used for both the 1-in-2 and 1-in-10 impacts. This is done because ex ante modeling resulted in a negative relationship between temperature and impacts. This relationship was due to the overall small impacts of the program and the 2022 event days' monopolization of all or most of the hot days, which can be problematic when establishing a relationship with temperatures. Despite the explanation for the results, the intention is to prevent negative impacts from occurring in the 1-in-10 weather scenario while still allowing for the ex ante forecasts to hold the negative relationship with temperature observed in ex ante modeling. Further, it allows for ex ante impacts that more closely match the reality of what was observed in PY 2022 (as estimated in the ex post analysis) and helps limit the range of ex ante aggregate impacts which are extremely sensitive to any change in per capita impacts due to the substantial size of participant population. Future evaluation work should reassess the relationship with A.6 ex ante impacts and temperatures. It may be that the PY 2022 weather effects are largely the result of correlation with event fatigue and repeated events.

5.6 PG&E EX ANTE IMPACTS B.2 CBP AGGREGATOR

Figure 5-9 presents the portfolio adjusted and program level ex ante per capita impact load shape for a Utility 1-in-2 Typical Event Day for subgroup B.2 CBP Aggregator participants. As seen in the portfolio adjusted impacts, there is a significant load reduction from CBP Aggregators, however, the majority of this impact is attributed to CBP with a much smaller ELRP ILR. Program level ex ante load shapes show very modest load reductions. This results from the generally modest response from B.2 Aggregators in the ELRP on non-CBP event days.

FIGURE 5-9: PG&E PORTFOLIO AND PROGRAM UTILITY 1-IN-2 TYPICAL EVENT DAY PER CAPITA LOAD SHAPE – SUBGROUP B.2 CBP AGGREGATOR

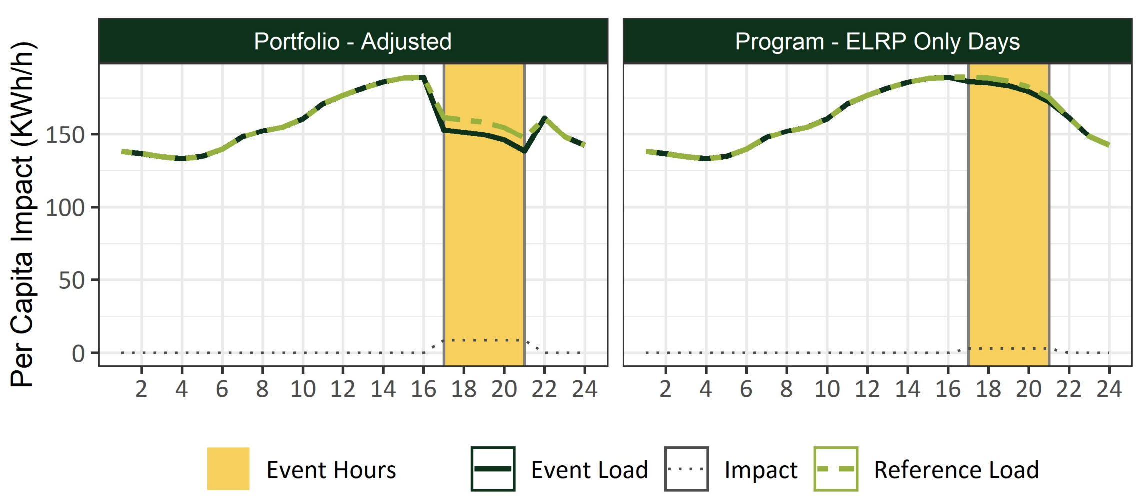


Table 5-8 presents the portfolio adjusted and program level per capita and aggregate ex ante impacts for the PY 2023 monthly system peak and the typical event day. The Utility 1-in-2 typical event day ex ante impacts associated with ILR are 8.7 MWh and 3.0 MWh for portfolio adjusted and program level ex ante impacts respectively.

TABLE 5-8: PY 2023 PORTFOLIO AND PROGRAM UTILITY 1-IN-2 TYPICAL EVENT DAY EX ANTE IMPACTS – SUBGROUP B.2 CBP AGGREGATOR

			Portfolio Adjusted			Program Level		
Day Type	Month	Num. of Parts.	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)	Avg. Reference Load (kWh/h)	Avg. Per Capita Impact (kWh/h)	Avg. MW Impact Reduction (MWh/h)
Monthly System Peak	May	602	146.4	8.8	5.3	174.7	3.1	1.8
	June	602	153.1	8.8	5.3	181.0	3.1	1.8
	July	602	153.7	8.8	5.3	181.6	3.1	1.8
	August	601	155.2	8.7	5.2	183.3	3.0	1.8
	September	601	155.1	8.7	5.2	183.1	3.0	1.8
	October	601	147.4	8.8	5.3	175.6	3.1	1.8
Typical Event Day	August	601	156.3	8.7	5.2	184.4	3.0	1.8

5.7 PG&E TOTAL ELRP EX ANTE FORECASTS PY 2023 THROUGH PY 2025

Table 5-9 and Table 5-10 provide the portfolio adjusted utility typical event day aggregate ex ante forecasts under 1-in-10 and 1-in-2 weather scenarios, respectively, by year. As seen the PY 2023 ex ante forecast is 79.9 MWh across all ELRP program segments covered in this evaluation and 75.4 MWh for 1-in-2 weather conditions.

Public Version. Confidential content removed and blacked out.

TABLE 5-9: UTILITY 1-IN-10 TYPICAL EVENT DAY EX ANTE AGGREGATE IMPACTS BY PROGRAM YEAR AND ELRP SUBGROUP – PORTFOLIO ADJUSTED

	Utility 1-in-10 Typical Event Day					
	PY 2023		PY 2024		PY 2025	
ELRP Subgroup	**Num. of Parts**	**MWh Forecast**	**Num. of Parts**	**MWh Forecast**	**Num. of Parts**	**MWh Forecast**
A.1 BIP	10	1.4	10	1.4	10	1.4
A.1 General - All	7,010	19.2	6,986	19.2	6,960	19.2
A.2 BIP*	111	3.6	111	3.6	111	3.6
A.4 VPP	4,292	7.1	4,292	7.1	4,292	7.1
A.6 Residential*	1,735,279	44.8	1,835,280	47.1	1,935,280	49.5
B.2 CBP	601	5.2	601	5.2	601	5.2
ELRP Total	**1,747,293**	**79.9**	**1,847,270**	**82.2**	**1,947,244**	**84.6**

*Indicates estimations based on Delivered Load

TABLE 5-10: UTILITY 1-IN-2 TYPICAL EVENT DAY EX ANTE AGGREGATE IMPACTS BY PROGRAM YEAR AND ELRP SUBGROUP – PORTFOLIO ADJUSTED

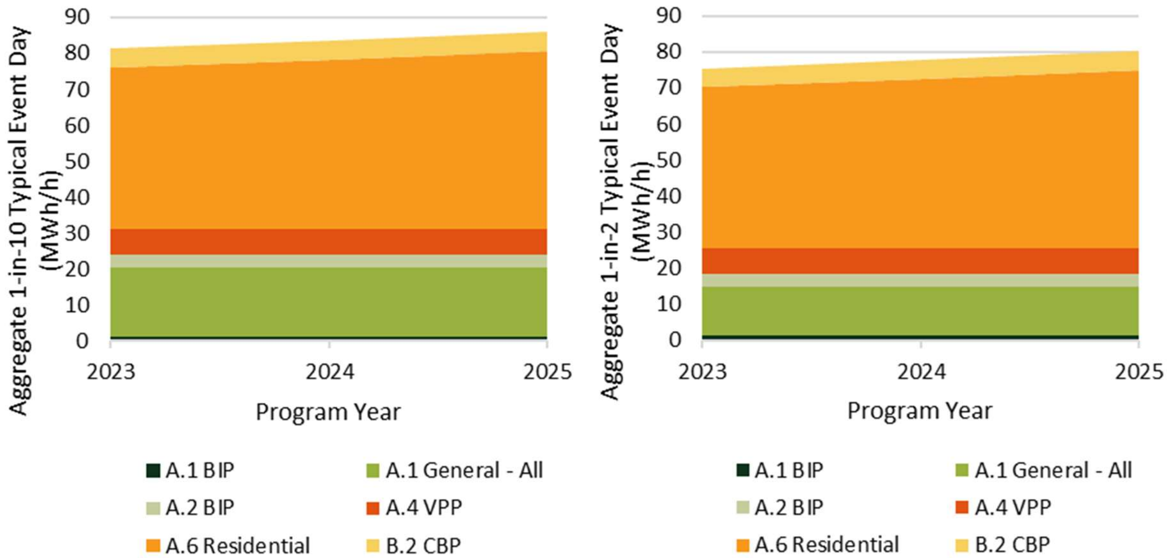
	Utility 1-in-2 Typical Event Day					
	PY 2023		PY 2024		PY 2025	
ELRP Subgroup	**Num. of Parts**	**MWh Forecast**	**Num. of Parts**	**MWh Forecast**	**Num. of Parts**	**MWh Forecast**
A.1 BIP	10	1.4	10	1.4	10	1.4
A.1 General - All	7,010	13.3	6,986	13.3	6,960	13.3
A.2 BIP*	111	3.6	111	3.6	111	3.6
A.4 VPP	4,292	7.1	4,292	7.1	4,292	7.1
A.6 Residential*	1,735,279	44.8	1,835,280	47.1	1,935,280	49.5
B.2 CBP	601	5.2	601	5.2	601	5.2
ELRP Total	**1,747,303**	**75.4**	**1,847,280**	**77.70**	**1,947,254**	**80.1**

*Indicates estimations based on Delivered Load

Figure 5-10 presents the MWh ex ante forecasts by year visually. As seen the largest driver for differences between the 1-in-10 and 1-in-2 weather scenarios is driven by subgroups A.1 General.

Public Version. Confidential content removed and blacked out.

FIGURE 5-10: PG&E 1-IN-10 (RIGHT) AND 1-IN-2 (LEFT) UTILITY TYPICAL EVENT DAY EX ANTE AGGREGATE IMPACTS BY PROGRAM YEAR AND ELRP SUBGROUP



6 EX POST AND EX ANTE COMPARISONS

This section presents comparisons between ex post and ex ante impacts. The Load Impact Protocols call for the following comparisons:

1) How the current ex post results differ from the prior year's ex post results;

2) How the current ex post results differ from last year's forecast;

3) How the current ex ante results differ from the prior year's forecast; and

4) How the current ex ante results differ from the current ex post results.

Given that PY 2022 is the first year with participation for many of the groups included in the ELRP, comparisons between the current year and prior year are not possible for all segments (comparison 1 and 3). The ex ante forecast for PY 2021 only included A.1 non-BIP participants, as a result, comparisons are made against PY2022 A.1 General Subgroup. For comparisons using PY 2022 ex ante portfolio adjusted impacts are used (comparison 3 and 4).

6.1 PY 2022 EX POST VERSUS PY 2021 EX POST

Table 6-1 presents a comparison between the PY 2021 and PY 2022 ex post average event days for groups A.1 General and A.2 BIP.

TABLE 6-1: COMPARISON OF PY 2021 AND PY 2022 EX POST IMPACTS

Subgroup	Program Year and Analysis Type	Num. of Parts	Avg. Reference Load (kWh/h)	Avg. Per Customer Impact (kWh/h)	Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
A.1 General	2021 Ex Post Avg. Event	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2022 Ex Post Avg. Event	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
A.2 BIP	2021 Ex Post Avg. Event	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2022 Ex Post Avg. Event	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Below we present key observations for each subgroup:

- **A.1 General:** The A.1 participant group saw similar weather conditions in PY 2021 and PY 2022. However, the per capita impacts were substantially lower in PY 2022 compared with PY 2021 ([redacted] kWh versus [redacted] kWh). There are a number of contributing factors that could have influenced this. These include the number of events and smaller participants' sizes. In PY 2021, the majority of participants only participated in three events versus ten events in PY 2022, most of which were consecutive event days. Participant fatigue could be a contributing factor. Additionally, reference loads were smaller indicating that the nearly 10x increase in the average event participation were primarily from customers with smaller loads.

- **A.2 BIP:** Participant counts and conditions were very similar between the PY 2021 and PY 2022 average event days, both of which only include dual BIP and ELRP event days. The difference in ex post impacts, however, is the incremental load reductions beyond participant's BIP FSL that was not seen in PY 2021. This resulted in an increased per capita load reduction from [redacted] kWh in PY 2021 to [redacted] kWh in PY 2022.

6.2 PY 2022 EX POST VERSUS PY 2021 EX ANTE

Table 6-2 represents the comparison between the PY 2021 ex ante forecast for 2022 and the PY 2022 ex post average event day for A.1 General. There are a number of items contributing to differences the ex-ante forecasts. First, the incentive increased from $1 per kWh in PY 2021 to $2 per kWh in PY 2022. The PY 2021 forecasts for 2022 included a 20% increase in the ex ante load reductions to account for the increase in incentives. However, the per capita impacts on the PY 2022 average event day were lower than the PY 2021 ex ante forecast, even if the 20% increase had not been included. Additionally, the ex ante enrollment forecast used in PY 2021 were substantially lower than actual 2022 enrollments in subgroup A.1 General. As a result, the PY 2022 ex post and PY 2021 ex ante were similar for aggregate impacts.

TABLE 6-2: COMPARISON OF PY 2021 EX ANTE IMPACTS FOR 2022 AND PY 2022 AVERAGE EVENT DAY EX POST IMPACTS

Subgroup	Program Year and Analysis Type	Num. of Parts	Avg. Reference Load (kWh/h)	Avg. Per Customer Impact (kWh/h)	Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
A.1 General	1-in-2 Typical Event Day	1,582	168.1	10.7	6.4%	16.9	93.5
	1-in-10 Typical Event Day	1,582	177.1	12.9	7.3%	20.4	97.0
	2022 Ex Post Avg. Event	6,476	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

6.3 PY 2022 EX ANTE VERSUS PY 2021 EX ANTE – ESTIMATES FOR 2023

Table 6-3 presents the PY 2021 and PY 2022 ex ante estimates for 2023 for the utility typical event day under 1-in-2 and 1-in 10 weather scenarios. In general, the current (PY 2022) ex ante estimates are smaller than those estimated in PY 2021. The drivers of this difference are the underlying participant forecasts used in each year and the weather adjusted impacts in observed in 2022 compared to those observed in

2021.The underlying impacts informing the PY 2022 ex ante tend to be smaller compared to those seen in A.1 General in 2021. Additionally, the current enrollment forecast has a higher share of smaller customers (in PY 2022) compared to those seen in A.1 General in PY 2021.

TABLE 6-3: COMPARISON OF PY 2021 EX ANTE IMPACTS AND PY 2022 EX ANTE ESTIMATES FOR PY 2023

Subgroup	Program Year and Analysis Type	Num. of Parts	Avg. Reference Load (kWh/h)	Avg. Per Customer Impact (kWh/h)	Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
A.1 General	1-in-2 Typical Event Day – PY 2021	1,582	168.1	10.7	6.4%	16.9	93.5
	1-in-10 Typical Event Day– PY 2021	1,582	177.1	12.9	7.3%	20.4	97.0
	1-in-2 Typical Event Day – PY 2022	7,010	104.0	1.9	1.7%	13.3	93.8
	1-in-10 Typical Event Day– PY 2022	7,010	105.3	2.7	2.6%	19.2	98.6

6.4 PY 2022 EX POST VERSUS PY 2022 EX ANTE FOR PY 2023

Table 6-4 presents comparisons between the ex post impacts and portfolio adjusted ex ante impacts on the typical event day under utility 1-in-2 and 1-in-10 weather conditions. Below we present key observations for each subgroup:

- **A.1 and A.2 BIP:** The portfolio adjusted ex ante impacts are the same for the utility 1-in-2 and 1-in-10 weather conditions but are smaller than the observed average event day ex post load impacts. This is the result of portfolio adjusted impacts being set to zero in the first two hours of the event window. The intention of the portfolio adjusted ex ante impacts for dually enrolled participants to provide load reductions that are incremental to the portfolio of utility DR programs. Conversely, the ex post impacts include load reduction in all hours of the event window, including load reduction prior to the start of BIP events. The hourly ex ante and ex post impacts during overlapping BIP hours are the same. However, the portfolio adjusted impacts do not count ELRP-only event hours in the hourly load reduction.
- **A.1 General**: Differences between the ex post average event day and the ex ante scenarios is largely driven by weather. The average event day in 2022 was extremely hot (100 F) and was hotter than the 1-in-10 weather scenarios. As a result of weather normalizing impacts in the ex ante analysis, impacts for the 1-in-2 ex ante are substantially lower than what was observed during 2022 events (1.9 kwh per capita versus [redacted] kWh per capita). However, the 1-in-10 weather scenario more closely aligns with observed 2022 weather and ex post impacts.
- **A.4 VPP**: Ex post and ex ante per capita impacts are nearly identical across weather scenarios. This is generally intuitive given that participation with battery storage is expected to be generally insensitive

to weather. The difference in the aggregate impacts is driven by increases in the number of enrolled A.4 participants.

- **A.6 Residential** While the difference in ex ante and ex post per capita impacts is not that different, the sheer volume of participants creates a substantial difference in the aggregate impacts forecasts (a difference of 9 MW). While there is a relationship between the temperature and ex ante impacts (as a result of weather normalizing impacts), the ex post analysis did not find a meaningful relationship with temperature which may be driving some of the differences between ex ante and ex post. As stated in the methodology section, up to four hotter days were removed from the ex ante modeling for some SubLAPs due to modeling challenges, this may also be driving some of the differences between the ex post and ex ante impacts.
- **B.2 CBP Aggregator**: The ex ante impacts for B.2 CBP participants are larger than the average event day impacts observed in 2022. This results from the inclusion of only dual program days in the portfolio adjusted ex ante impacts. Typically, CBP curtailments were lower in on ELRP only event days, which are included in the ex post average event day.

TABLE 6-4: COMPARISON OF PY 2022 EX ANTE UTILITY TYPICAL EVENT DAY IMPACTS AND PY 2022 EX POST IMPACTS

Subgroup	Program Year and Analysis Type	Num. of Customers	Avg. Per Customer Impact (kWh/h)	Percent Load Reduction	Avg. MW Impact Reduction (MWh/h)	Avg. Temp (F)
A.1 BIP	Ex Post Avg. Event	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	1-in-2 Typical Event	10	138.5	11.6%	1.4	82.0
	1-in-10 Typical Event	10	138.5	11.4%	1.4	87.9
A.1 General	Ex Post Avg. Event	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	1-in-2 Typical Event	7,010	1.9	1.8%	13.3	94.8
	1-in-10 Typical Event	7,010	2.7	2.6%	19.2	98.7
A.2 BIP	Ex Post Avg. Event	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	1-in-2 Typical Event	111	32.0	7.5%	3.6	95.1
	1-in-10 Typical Event	111	32.0	7.4%	3.6	98.9
A.4 VPP	Ex Post Avg. Event	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	1-in-2 Typical Event	4,292	1.7	--	7.1	84.4
	1-in-10 Typical Event	4,292	1.6	--	7.1	89.7
A.6 Residential*	Ex Post Avg. Event	1,495,382	0.04	1.9%	53.9	91.3
	1-in-2 Typical Event	1,735,279	0.03	1.4%	44.8	89.9
	1-in-10 Typical Event	1,735,279	0.03	1.4%	44.8	94.8
B.2 CBP Aggregator	Ex Post Avg. Event	567	2.0	1.1%	1.1	93.7
	1-in-2 Typical Event	601	8.7	5.6%	5.2	88.3
	1-in-10 Typical Event	601	8.7	5.5%	5.2	92.7

7 FINDINGS AND RECOMMENDATIONS

This section presents the findings and recommendations from the PY 2022 PG&E ELRP Load Impact Evaluation.

- **Finding 1**: All A.6 ELRP event days were dual ELRP/Flex Alert days. The reported ELRP ex post impacts are the sum of the incremental ELRP and Flex Alert impacts. The analysis of load reductions for A.6 residential enrollment status (CARE auto-enrolled, FERA auto-enrolled, HER auto-enrolled, and self-enrolled), found that the reported ex post impacts for the auto-enrolled subgroups were largely Flex Alerts impacts with no or very little incremental ELRP load reduction. The self-enrolled ELRP participants, however, reduced their reference baseline load by an average of 10.4% during ELRP event hours and approximately 70% of the average load reduction was incremental ELRP impacts.
  - **Recommendation 1**: Program managers should attempt to increase the number of self-enrolled ELRP participants to increase the ELRP incremental load reduction.
  - **Recommendation 2**: If the goal of the ELRP is to compensate participation in Flex Alerts rather than provide incremental load reductions to Flex Alerts, then ELRP should continue to auto-enroll participants. If the goal of the ELRP is to compensate customers for incremental load reduction, then ELRP should consider discontinuing auto-enrollment of customers.
- **Finding 2**: For Group A.4 residential VPP participants, the full level of load curtailment lasts for only a maximum of two hours and then severely dissipates in the third hour. During longer duration events, the participants' batteries are often charging during the early and/or late event hours, reducing the average hourly load reduction during those events.
  - **Recommendation 3**: Work with VPP aggregators to discharge battery charging during event windows and shorten A.4 event length windows to strategically target two to three hours of the RA window.
- **Finding 3**: For Group A.4 residential VPP participants, the aggregator discharged all, or nearly all, participant batteries during a set two-hour time period.
  - **Recommendation 4**: If load reduction is needed over a longer duration, PG&E should work with the VPP aggregators to distribute the battery discharge over the duration of the event window.
- **Finding 4**: As in PY 2021, subgroup A.1 ELRP participant nominations were overstated compared with evaluated ex post load reductions. Given that the ELRP provides incentives for load reductions without any penalties for missing stated load reductions, there is no mechanism in the ELRP that holds participants to their stated nominations.
  - **Recommendation 5**: Participant nominations are a useful way of understanding how much curtailable load is available as a DR resource. However, the program design of the ELRP does not hold participants accountable for nominated load reductions. Program managers should attempt

to track how settlement load reductions compare with ELRP participants' stated nominations over the course of the ELRP event season to help inform expectations of load reductions for upcoming events.

- **Finding 5**: The ex post analysis found that there were additional load reductions for A.1 BIP customers outside of dual program days, but not substantial reductions for A.2 BIP aggregators. This suggests that there may be a willingness for BIP participants individually enrolled in the ELRP to curtail on ELRP only days.
  - **Recommendation 6**: The ELRP should consider compensating BIP participants for all ELRP program event days, not just overlapping BIP event hours.

APPENDIX A TABLE GENERATORS

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

- Appendix A-1: *PG&E_PY2022_ELRP_Ex_Post_Table_Generator_Subgroups_A.1_A.2_A.4_and_B.2_PUBLIC.xlsx*
- Appendix A-2: *PG&E_PY2022_ELRP_Ex_Post_Table_Generator_Subgroup_A.6_PUBLIC.xlsx*
- Appendix A-3: *PG&E_PY2022_ELRP_Ex_Ante_Table_Generator_Subgroups_A.1_A.2_A.4_and_B.2_PUBLIC.xlsx*
- Appendix A-4: *PG&E_PY2022_ELRP_Ex_Ante_Table_Generator_Subgroup_A.6_PUBLIC.xlsx*

APPENDIX B PROXY DAY TESTING PERFORMANCE

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

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

The preference for these metrics was based primarily on a shortcoming of the MAPE and MPE when it comes dealing with observed values of zero, which will result in division by zero error and the loss of the data point. Table B-1 presents descriptions and the equations for two metrics calculated for accuracy and the three calculated for precision. One thing to note is that for the NMBE and NMAE, the formulas go against a convention seen in some contexts (e.g., ASHRAE), where the error is calculated as the baseline minus the observed. This runs contrary to the more typical conventions of calculating MPE and MAPE, so for the sake of consistent interpretation of the NMBE and MPE, where negative values indicate overestimation of the baseline, Verdant has calculated the error as the observed load minus the calculated baseline for all metrics.

TABLE B-1: DESCRIPTIONS AND EQUATIONS FOR PERFORMANCE METRICS

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

Table B-2 through Table B-7 present summaries of the model performance metrics on proxy event days. For non-residential subgroups these metrics are show by NAICs description. For A.4 and A.6 these metrics are presented by LCA and by NEM status and enrollment groups respectively Overall, the models have good performance, with some expected variability based on industry type. The more industrial participants have poorer model performance, which is expected given the volatile load associated with many of these customers. In contrast, office and retail customers, which have more consistent occupancy and operations as well as weather-sensitivity, have the best performance metrics.

Public Version. Confidential content removed and blacked out.

B.1 PERFORMANCE METRICS

TABLE B-2: SPECIFICATION TEST RESULTS FOR PROXY DAY TESTING - PG&E SUBGROUP A.1 BIP

NAICS	Num. of Customers	CV RMSE	NMBE	NMAE	Adjusted R^2
Agriculture, Mining & Construction	2	0.009	0.001	0.007	0.871
Manufacturing	1	0.006	0.000	0.004	0.961
Offices, Hotels, Finance, Services	1	0.002	0.000	0.001	0.421
Other	1	0.006	0.000	0.004	0.977
Retail Stores	2	0.001	0.000	0.001	0.972
Wholesale, Transport, Other Utilities	2	0.012	-0.001	0.008	0.737
Agriculture, Mining & Construction	2	0.009	0.001	0.007	0.871

TABLE B-3: SPECIFICATION TEST RESULTS FOR PROXY DAY TESTING - PG&E SUBGROUP A.1 GENERAL

NAICS	Num. of Customers	CV RMSE	NMBE	NMAE	Adjusted R^2
Agriculture, Mining & Construction	3,423	0.147	0.037	0.118	0.733
Institutional/Government	477	0.016	0.002	0.011	0.808
Manufacturing	122	0.006	0.000	0.004	0.834
Offices, Hotels, Finance, Services	1,038	0.009	0.001	0.007	0.855
Other	14	-0.002	-0.015	-0.005	0.686
Retail Stores	214	0.006	0.002	0.004	0.860
Schools	14	0.012	0.002	0.009	0.879
Wholesale, Transport, Other Utilities	1,009	0.271	0.048	0.216	0.769
Unknown	56	0.525	0.232	0.363	0.819

TABLE B-4: SPECIFICATION TEST RESULTS FOR PROXY DAY TESTING - PG&E SUBGROUP A.2 BIP

NAICS	Num. of Customers	CV RMSE	NMBE	NMAE	Adjusted R^2
Agriculture, Mining & Construction	47	0.461	0.304	0.364	0.775
Manufacturing	29	0.008	-0.001	0.006	0.801
Offices, Hotels, Finance, Services	1	0.016	0.000	0.012	0.715
Wholesale, Transport, Other Utilities	30	0.016	0.002	0.012	0.774
Agriculture, Mining & Construction	47	0.461	0.304	0.364	0.775
Manufacturing	29	0.008	-0.001	0.006	0.801
Offices, Hotels, Finance, Services	1	0.016	0.000	0.012	0.715

Public Version. Confidential content removed and blacked out.

TABLE B-5: SPECIFICATION TEST RESULTS FOR PROXY DAY TESTING - PG&E SUBGROUP A.4 VPP BY SEGMENT

Local Capacity Area	Num. of Segments	CV RMSE	NMBE	NMAE
Greater Bay Area	27	0.011	0.007	0.008
Greater Fresno Area	4	0.040	-0.003	0.025
Humboldt	3	0.099	-0.044	0.063
Kern	1	0.012	-0.003	0.009
North Coast and North Bay	11	0.050	0.028	0.036
Other	16	-0.046	-0.006	-0.034
Sierra	5	-0.065	0.090	-0.062

TABLE B-6: SPECIFICATION TEST RESULTS FOR PROXY DAY TESTING - PG&E SUBGROUP A.4 VPP BY SEGMENT

NEM Status	Enrollment Group	Num. of Customers	CV RMSE	NMBE	NMAE	Adjusted R^2
NEM	Auto-enrollment CARE	6,790	0.085	-0.013	0.070	0.507
NEM	Auto-enrollment FERA	2,307	0.051	0.012	0.041	0.503
NEM	Auto-enrollment HER	9,733	0.117	0.008	0.088	0.458
Non-NEM	Auto-enrollment CARE	11,793	0.059	-0.015	0.048	0.593
Non-NEM	Auto-enrollment FERA	9,640	0.067	-0.021	0.054	0.599
Non-NEM	Auto-enrollment HER	13,321	0.058	0.009	0.048	0.568
Non-NEM	Self-Enrollment	1,520	0.039	-0.007	0.033	0.605

TABLE B-7: SPECIFICATION TEST RESULTS FOR PROXY DAY TESTING - PG&E SUBGROUP B.2 CBP AGGREGATOR BY SEGMENT

NAICS	Num. of Customers	CV RMSE	NMBE	NMAE	Adjusted R^2
Agriculture, Mining & Construction	148	1.543	0.685	1.184	0.743
Institutional/Government	34	0.007	0.000	0.005	0.912
Manufacturing	13	0.009	0.002	0.007	0.758
Offices, Hotels, Finance, Services	9	0.014	-0.002	0.008	0.885
Other	1	0.003	0.000	0.002	0.727
Retail Stores	299	0.000	-0.001	0.001	0.942
Wholesale, Transport, Other Utilities	36	0.415	-0.144	0.304	0.745

Public Version. Confidential content removed and blacked out.

B.2 ACTUAL VS PREDICTED PROXY DAY LOAD SHAPES

As a means of visually assessing how well the statistical models predicted usage, Figure B-1 through Figure B-6 show the average actual and predicted load on proxy event days for ELRP subgroup. In general, these figures show good model fits. However, these us some level of deviation from predicted loads across subgroups.

FIGURE B-1: PG&E PROXY DAY ACTUAL VS. PREDICTED LOAD – A.1 BIP

[redacted]

FIGURE B-2: PG&E PROXY DAY ACTUAL VS. PREDICTED LOAD – A.1 GENERAL

[redacted]

Public Version. Confidential content removed and blacked out.

FIGURE B-3: PG&E PROXY DAY ACTUAL VS. PREDICTED LOAD – A.2 BIP

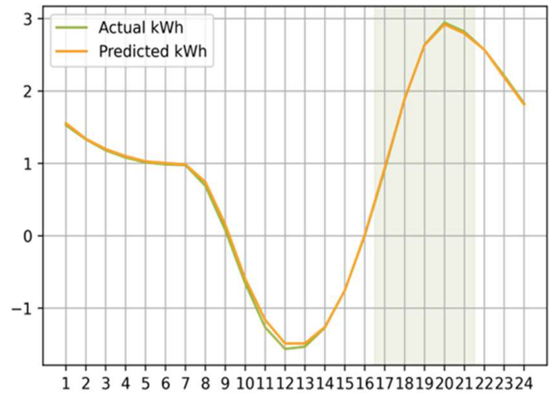
[redacted]

FIGURE B-4: PG&E PROXY DAY ACTUAL VS. PREDICTED LOAD – A.4 VPP

[redacted]

Public Version. Confidential content removed and blacked out.

FIGURE B-5: PG&E PROXY DAY ACTUAL VS. PREDICTED LOAD NEM (RIGHT) AND NON-NEM (LEFT) – A.6 RESIDENTIAL



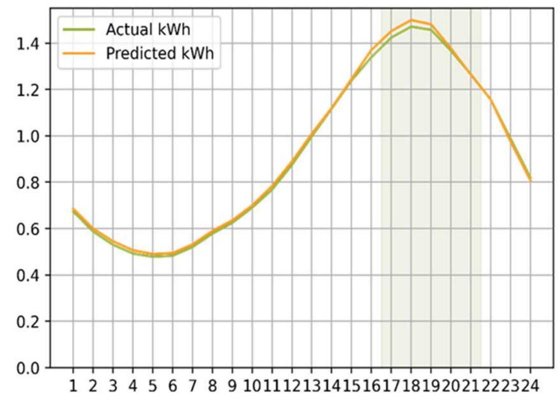


FIGURE B-6: PG&E PROXY DAY ACTUAL VS. PREDICTED LOAD – AB.2 CBP AGGREGATOR