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Re: **UE 272/UM 1514 Automated Demand Response – Phase 2 Report**

In accordance with Commission Order No. 13-172, enclosed is PGE's second report on the Automated Demand Response pilot including the third-party evaluation from Itron.

If you have any questions or require further information, please call me at (503) 464-7623. Please direct all formal correspondence and requests to the following email address: pge.opuc.filings@pgn.com.

Sincerely,

Alex Tooman

Alex Tooman
Project Manager, Regulatory Affairs

AT/sp

cc: Jason Salmi Klotz, OPUC
Rebecca Brown
Gregory Davis
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PGE Report on Automated Demand Response Pilot

Introduction

Commission Order No. 13-172 (Docket No. UE 272) approved PGE's Energy Partner^{SM} automated demand response (Energy Partner or ADR) pilot and adopted timeline. In this timeline, PGE was required to file an evaluation report on the progress of the Energy Partner pilot in April 2016.[1] If the evaluation is favorable, PGE planned to "submit the ADR Program as an ongoing capacity resource in its Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (Schedule 126), similar to the manner in which the Company handles other power cost and capacity items."

As is detailed in this report and in the attached Third-Party Evaluation (ITRON), the Energy Partner Program has grown significantly since it began in 2013. PGE has learned a tremendous amount about the marketing of demand response to large customers and the ability of an ADR program to help cost-effectively meet the Company's capacity needs on peak days. The program has been successful in many ways, but PGE plans to request to extend the pilot another year to further solidify and stabilize the program before including it in its Annual Power Cost Update and Power Cost Adjustment Mechanism. Accordingly, another report will be filed in April 2017, and if it is favorable, PGE will then treat the ADR program similar to the manner in which the Company handles other power cost and capacity resources.

Status of the Energy Partner Program

Program growth
The Energy Partner pilot began operations in August 2013. As Table 1 shows, the program has seen steady growth during its first six seasons.

Table 1: Growth in Energy Partner over First Six Operating Seasons

	Summer 2013	Winter 2013/14	Summer 2014	Winter 2014/15	Summer 2015	Winter 2015/16
Customers	2	3	17	23	27	36
Nominated Demand	250 kW	300 kW	2,745 kW	6,745 kW	9,205 kW	11,200 kW
Increase compared to previous season	--	20%	815%	146%	36%	22%

The program's growth accelerated significantly in the past four seasons for a variety of reasons, including successful efforts to shorten the relatively long sales cycle required to enroll a large

[1] Commission Order No. 15-085 allowed an extension to April 29, 2016 for PGE to submit the evaluation report.

customer in ADR, particularly in this region where most customers had never been offered or exposed to demand response prior to PGE beginning this program.

The program also became more successful due to a number of improvements PGE made to the sales and marketing effort. Below, we summarize our efforts to grow customer enrollment, participation and satisfaction.

- **Improving commissioning process efficiency**: Early in the program, customers identified delays in the installation of equipment, but EnerNOC staff identified the problem and solved it. New customers report no problems with installations.

- **Communications**: We have created Oregon-specific case studies, videos, and advertising. Additionally, we are attending, sponsoring, and promoting Energy Partner at industry-specific events hosted by high potential groups such as the NW Food Processor Association and Oregon Manufacturers Association.

- **Customer Pre-Identification**: To increase the size and pace of enrollments, PGE now provides EnerNOC with discrete load profiles to pre-identify potential candidates for participation (in a manner that maintains confidentiality agreements regarding customer data).

- **Employee Incentives**: To increase the pace of program growth, PGE began offering financial incentives to Key Customer Managers (KCMs) in 2015 for the enrollment of large customers. One KCM has thus far earned the incentive.

- **DSG Customers**: After deliberation, PGE allowed customers enrolled in its Dispatchable Standby Generation (DSG) program to enroll in the Energy Partner program.[2] Several large users began participating in the fifth season due to this change.

Due to these improvements, PGE has seen a 66% increase in enrolled capacity from the 2014/15 winter season to the 2015/16 winter season. Also, while in 2013 and 2014, it took EnerNOC an average of 120 days to close a transaction, that number decreased to 70 days in 2015, indicating that market education has been effective.

Nevertheless, the program is not on track to achieve its goal of 25 MW of enrolled capacity by 2017. Indeed, in recent discussions EnerNOC has stated that they do not believe the program can

[2] DSG Customers participate by installing EnerNOC equipment and reducing their load without the assistance or use of their back-up generators.

ever achieve 25 MW, despite their contractual obligation to achieve this goal by 2017. They have identified 15.3-18.2 MW as the likely upper-bound of the program's total enrollment.

The overwhelming reason for the lower than projected program enrollment is that PGE's largest customers tend to be direct access and/or in high-tech industries, such as data centers and semiconductor manufacturers, that do not lend themselves to participation in demand response programs. EnerNOC's program is primarily targeted towards customers with greater than 1 MW of load, and PGE simply lacks sufficient customers of that size in industries – like waste water treatment plants – whose load profiles and reliability needs match participation in ADR.

Event Performance

The Energy Partner portfolio's performance has been erratic, but has proven a valuable resource for PGE's power operations. Aggregate seasonal results are listed in Table 2, below:

Table 2: Event Realization Rates for First six Operating Seasons

	Summer 2013	Winter 2013/14	Summer 2014	Winter 2014/15	Summer 2015	Winter 2015/16
Number of Events	3	5	6	1	4	3
Average Number of Participants	2	2.4	13.7	37	45.25	56.7
Realization Rate	170%	135%	98%	68%	86%	59%

The poor performance in the two most recent winter seasons was likely due to two factors:

- The one event was on December 30, during the week between Christmas and New Year's Day when loads are typically low; and
- The remaining events were called during marginal days, due to the mild weather, for evaluation purposes (one of which was to test a 10-minute response).

Customer Satisfaction

Customer satisfaction with the program has increased significantly in the past year. In the first evaluation report, released in April 2015, only 45% of 11 customers responding to a survey said that they were very or somewhat satisfied with the program. Thirty-six percent of customers said they were dissatisfied, while 18% said it was too early to say. As Table 3 below demonstrates, customer satisfaction has risen sharply this year.

Table 3: Level of Customer Satisfaction with Energy Partner in 2016

Level of Customer Satisfaction	Percentage of Respondents (n=20)
Very Satisfied	60%
Somewhat Satisfied	30%
Dissatisfied	5%
Undecided	5%

Of the surveyed customers, 75% reported they are very likely to continue participation in the program, and 25% said they are likely. One of the respondents said he planned to continue participating because, "There are no drawbacks and everybody benefits from the program."

Planned Improvements

The evaluation report identified a number of additional opportunities for improvement. The following list provides these opportunities along with our intended actions:

- **Reach out to customers who have already declined participations**: Following adjustments to the contract with EnerNOC, PGE plans to re-engage customers that had initially declined participation and/or those that were previously disqualified. We will also discuss the possibility of participating in schedule 77 if that is a better fit for them.
- **Coordinate with Energy Trust**: PGE has already begun to engage with Energy Trust on cross-marketing our respective programs. Our staff plans to attend some of Energy Trust's strategic energy management (SEM) workshops to better understand which customers might be a good fit for the program.
- **Expand enrollment to also include customers who can only participate in some program hours**: This would most likely involve giving customers the option to enroll in specific blocks of the peak period. PGE is currently exploring this option internally to understand how this adjustment would affect the program's payment structure.
- **Leverage AMI data to reach potential participants**: EnerNOC generally prefers to have real-time monitoring of participant load to ensure that corrections can be made to curtailment strategies up to- and during events. As the program has grown, EnerNOC has become more open to having a limited number of participants that are monitored using their standard AMI meter(s). We are already beginning to explore potential customers where this might be preferable.
- **Fine-tune customer messaging**; The more that we and EnerNOC learn about what aspects of demand response resonate with our customers, the better we are getting at messaging the program. We anticipate continuing improvement in this regard.
- **Develop strategic partnerships with control companies and engineering firms**: While PGE already has some relationship with vendors in our area, we believe that our

engagement with the Energy Trust's SEM program will provide an opportunity to expand these relationships.

Impacts on Power Operations

The Energy Partner program established a goal of 25 MW and included a requirement to be able to call events within ten minutes due to requirements established by PGE's Power Operations group. Now that the program has called a number of events, PGE has a more nuanced opinion. First, while 25 MW remains a goal for the portfolio of demand response programs, [3] the group now recognizes the value of having any demand response on peak days. On particularly hot days, like July 30, 2015, any amount of demand response can be helpful, though having at least 25 MW is needed for a tradable block of power.

Conclusions and Recommendations

PGE believes there are three conclusions to draw from the second ADR pilot report:

- The Energy Partner program is a cost-effective way to meet capacity needs and should continue into the future.

- It is premature to submit the ADR Program as an ongoing capacity resource in PGE's Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (Schedule 126), because the contract with EnerNOC needs to be updated.

    - For PGE to continue its Energy Partner program with EnerNOC past 2016, the contract must be amended. As written, the contract allows either party the option to terminate at the end of 2016, and the existing terms require EnerNOC to achieve 25 MW in 2017 or pay a significant penalty. EnerNOC does not believe the program can achieve 25 MW in its current form, and so would void the contract if it were not amended to avoid the penalty payments.

    - In amending the contract, PGE and EnerNOC can find ways to increase the success of Energy Partner going forward. One example is by amending the penalties and incentives EnerNOC receives for underachieving or overachieving program goals. These incentives can be structured to induce EnerNOC to

[3] Schedule 77 curtailable load program, the Bring-Your-Own-Thermostat residential program, and the emerging Residential Pricing Pilot's Peak Time Rebate and Behavioral Demand Response program options in addition to ADR

nominate loads more accurately in order to consistently achieve 95-105% realization rates, making the program as effective as possible for PGE's energy traders. As another example, PGE plans to allow EnerNOC to nominate demand more regularly – currently EnerNOC nominates demand for an entire month at the beginning of the month. By implementing this change, the actual amount of load available on peak days should more closely match the nominated amount, and the realization rate of events should move closer to 100%. An additional example would be to eliminate the 10-minute minimum response time, which should increase enrollments and/or nominations.[4]

- Amending the contract could allow PGE to explore allowing other vendors to provide demand response to its business customers. Under the existing contract, EnerNOC has exclusive access to provide an ADR program to PGE's customers above 30 kW. Because EnerNOC's program is targeted towards PGE's largest customers (almost exclusively >200 kW), there may be the potential to achieve additional MWs of demand response from medium sized businesses by working with a separate vendor. PGE is actively exploring this potential.

PGE's recommendation is to continue the pilot through 2017 with modifications to increase enrollment and solidify enrolled capacity and realization rates. We will be lowering the targeted enrolled capacity consistent with EnerNOC's revised projections. We will also pursue options for our medium-sized business customers –underserved by the current program –to make up for the shortfall in capacity. Our working assumption is that barring unexpected and unforeseen complications, in April 2017, the program under EnerNOC will be submitted in PGE's 2018 Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (Schedule 126).

[4] The 10-minute notification was initially put in place to mimic the performance of a thermal plant. Following conversations with our real time traders and through development of a cost-effectiveness framework, we have determined that simply having day-of notice within at least a few hours is sufficient to justify the program costs.

Final Phase II Report

Portland General Electric Energy Partner Program Evaluation

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March 31, 2016

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Executive Summary

ES.1 Program Overview

Portland General Electric (PGE)'s Automated Demand Response (ADR) program, known as Energy Partner℠, enables participants to receive payments for reducing electricity consumption during peak usage periods. Program events may be called at PGE's discretion and typically coincide with peak demand on the electric grid (e.g., hot summer or cold winter days). The program is operated by a third party aggregator, EnerNOC Inc. (EnerNOC), which is responsible for program implementation. This includes recruiting eligible large non-residential PGE customers, installing curtailment hardware and software, and providing financial settlement services. The program is currently in the pilot stage.

ES.1.1 Program and Evaluation Timeframe

The curtailment events can occur during both the program's summer (July, August, and September) and winter (December, January, and February) seasons. The seasons covered by this report are Summer 2013, Winter 2013-14, Summer 2014, Winter 2014-15, and Summer 2015.

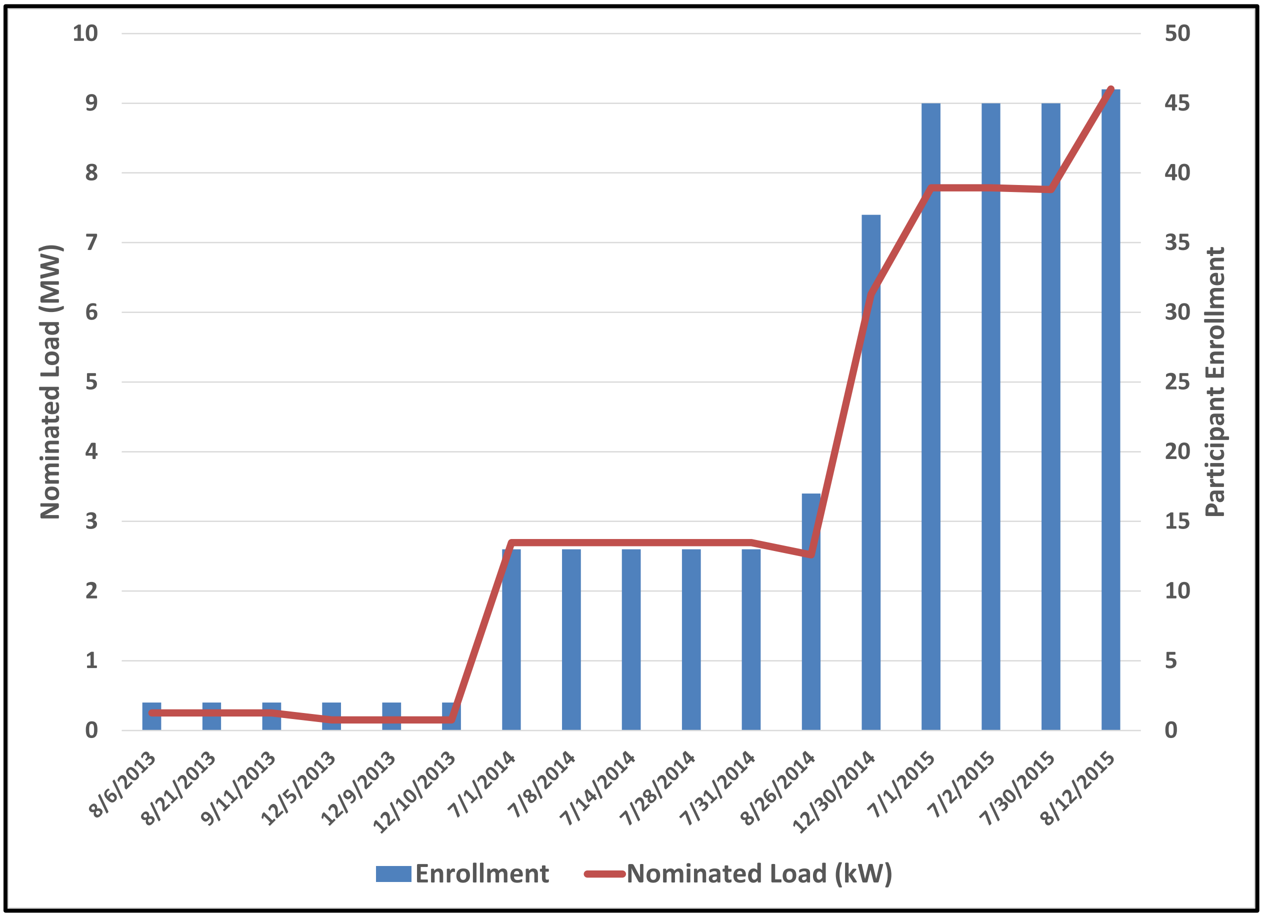
Findings from this evaluation are divided into two phases. Phase I represents the evaluation activities conducted during the first three seasons of program implementation. These findings have already been presented in the first evaluation report. Phase II includes the new evaluation activities that were conducted on behalf of Seasons 4 and 5, and the findings are presented in this report.

Phase I			Phase II	
Season 1	**Season 2**	**Season 3**	**Season 4**	**Season 5**
Summer 2013	Winter 13-14	Summer 2014	Winter 14-15	Summer 2015

The program aims to provide a total of 25 MW of peaking capacity to the PGE system by July1, 2017. Figure ES-1 illustrates the program's progress in nominated curtailable load and participant (number of individual facilities[1]) enrollment across all events through the first five seasons. While the nominated load was just over 9 MW as of the last actual event, by September 2015 the program's enrollment had increased to approximately 12 MW of nominated load at the time of this writing.

[1] A single customer can separately enroll several geographically different facilities.

Figure ES-1: Nominated Load and Enrollment by Event



ES.1.2 Status of Outreach Efforts

As of the August 2015 nomination report submitted by EnerNOC, there were 46 participating facilities (i.e., unique participating locations), which were represented by 27 participant organizations. One customer officially dropped out of the program before the start of the third season. Two customers who did not officially drop out but reported that they were unlikely to continue participation have been retained in the nomination report but have been nominated at 0 kW. These figures are summarized in Table ES-1.

Table ES-1: Participation Overview, as of August 2015 Nomination Report

Status	Customer Organizations	Participating Facilities
Participants	27	46
Officially Dropped Out	1	1
Unlikely to Continue Participation	2	2

ES.2 Findings

ES.2.1 Load Impacts: Findings

The following summarizes the load impacts for Phase I and Phase II of the Energy Partner program.

Phase I—Seasons 1 through 3

Table ES-2 summarizes the load impacts for the first three seasons of the Energy Partner program. The level of realized impacts relative to the nominated load is measured in terms of a realization rate.[2].

Table ES-2: Season 1 through Season 3 Event Summary

Event Date	Event Hours	Peak Event Day Temp.	Number of Participants	Nominated Load (kW)	Average Hourly Impact (kW)	Realization Rate
8/6/2013	4-6 p.m.	91º F	2	250	540	216%
8/21/2013	3-6 p.m.	90º F	2	250	347	139%
9/11/2013	4-7 p.m.	95º F	2	250	387	155%
12/5/2013	5-8 p.m.	32º F	2	150	216	144%
12/9/2013	7-9 a.m.	29º F	2	150	338	225%
12/10/2013	6-8 p.m.	34º F	2	150	316	211%
2/5/2014	4-6 p.m.	29º F	3	300	283	94%
2/6/2014	4-6 p.m.	23º F	3	300	262	87%
7/1/2014	4-6 p.m.	99º F	13	2,695	2,942	109%
7/8/2014	4-6 p.m.	88º F	13	2,695	2,624	97%
7/14/2014	3-7 p.m.	85º F	13	2,695	1,187	44%
7/28/2014	4-6 p.m.	92º F	13	2,695	2,373	88%
7/31/2014	2-6 p.m.	91º F	13	2,695	3,560	132%
8/26/2014	4-8 p.m.	93º F	17	2,520	3,009	119%

The first season only saw two program participants with a total nominated load shed of 250 kW. These participants performed better than the nominated load overall.

The second season ran from December 1, 2013 through February 28, 2014. Five events were called during this season. The portfolio performed better than the nominated load shed for the first three events but came up shy of the nominated load for the last two events.

2 Realization Rate is equal to the load impact divided by the nominated load.

In Season 3 (the second summer season), there was a significant increase in the number of program participants and the amount of nominated load. By the second month of this season, 17 customers had enrolled in the Energy Partner program for a total of 2.52 MW of nominated load shed. The July 14 event had considerably lower impact than the other events. According to PGE staff, some customers reported "event fatigue" during this timeframe and two water authorities, who represent a large amount of nominated load, could not curtail.

Phase II—Seasons 4 through 5

The load impacts for the two seasons in Phase II of the Energy Partner program are summarized in Table ES-3.

Table ES-3: Season 4 and Season 5 Event Summary

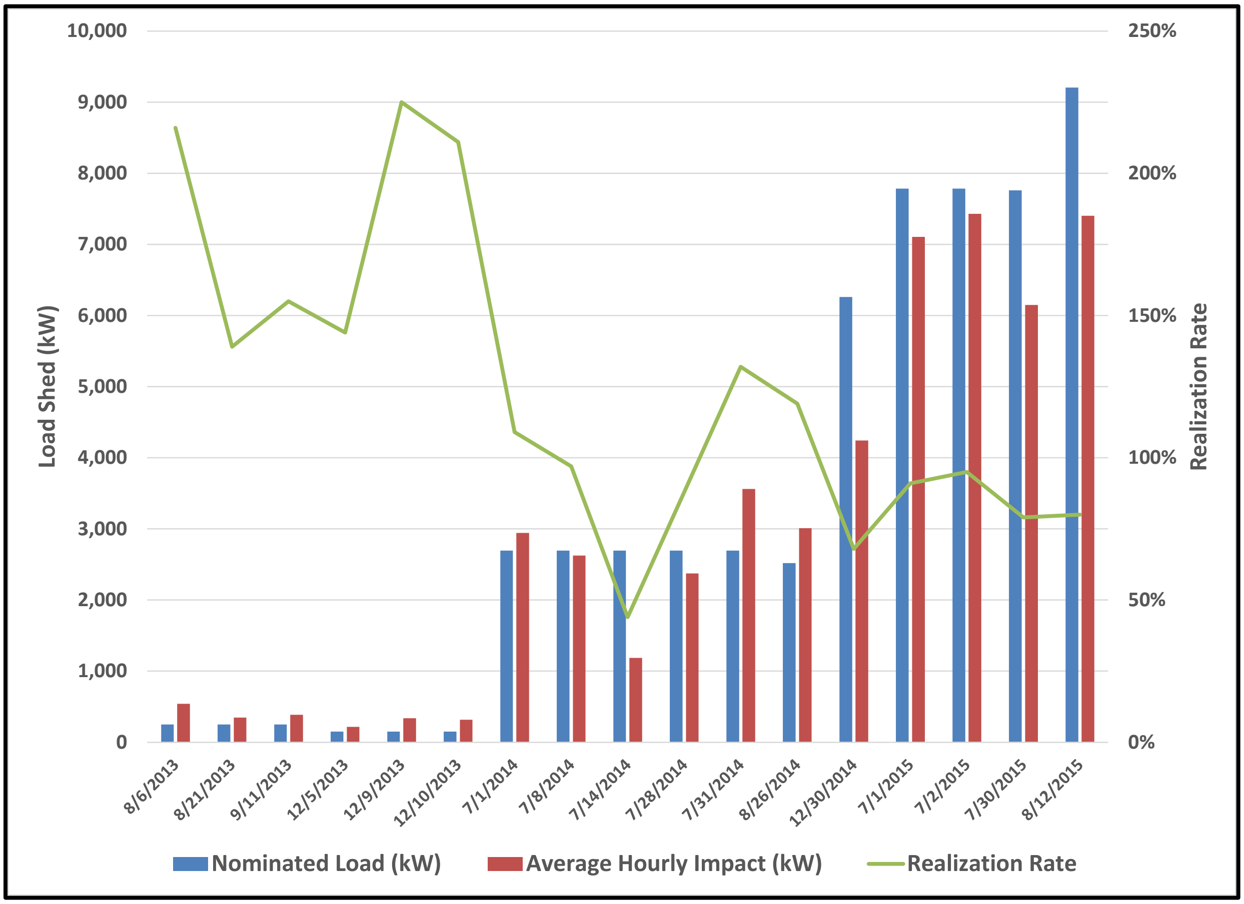
Event Date	Event Hours	Peak Event Day Temp.	Number of Participants	Nominated Load (kW)	Average Hourly Impact (kW)	Realization Rate
12/30/2015	6-8 p.m.	34	37	6,260	4,243	68%
7/1/2015	3-7 p.m.	95	45	7,785	7,107	91%
7/2/2015	3-7 p.m.	97	45	7,785	7,431	95%
7/30/2015	3-7 p.m.	103	45	7,760	6,148	79%
8/12/2015	4-8 p.m.	91	46	9,205	7,404	80%

In the fourth season, only one event was called and this was on December 30. Both winters (Season 2 and Season 4) covered by the evaluation were unseasonably warm. The realized load shed was only 68% of the nominated load. This low performance may have been partially a result of the day falling between Christmas and New Year.

The enrollment in the fifth season increased significantly over the previous season, raising the nominated load to over 9 MW. Four events were called during this summer season and the weighted realized load shed was 86% of the nominated load.

Figure ES-2 shows the performance trend of the Energy Partner program over the first five seasons. The nominated load and actual load shed has increased over time. The realization rate of the impacts has declined over this period, but it appears to be leveling out in Season 5. This may be a function of the maturity of the program and number of customers enrolled.

Figure ES-2: Season 1 through 5 Nominated Load, Load Impact, and Event Realization Rates



ES.2.2 Supplemental Load Analyses: Findings and Recommendations

In addition to the load impact analysis, the evaluation team conducted four supplemental load analyses for the Phase II report. These additional tasks included:

- **Participant Load Characterization**: A classification of participant sites based on load variability and temperature sensitivity.
- **Regression Baseline Modeling**: The use of statistical models to develop participant baselines as an alternative to PGE's "5 highest of 10 days with morning adjustment" methodology, which is the current baseline used for settlement.

- **Proxy Event Analysis**: Baselines were estimated for several proxy event days—days with weather similar to those of actual events—using PGE's settlement baseline approach and the regression model approach. Both an additive adjustment factor and a multiplicative adjustment factor were tested with each baseline method. The accuracy and bias were measured for all combinations.
- **Curtailment Response Speed Analysis**: An analysis of the degree to which participants are able to meet their curtailment targets quickly at the start of events, with particular interest in the sites' types of curtailment controls (manual versus automated).

These supplemental load analyses have potential implications for the program in several areas.

Load Characterization Findings

In general, the estimated impacts of those participants with high load variability and/or low temperature sensitivity are potentially highly inaccurate. There was clear heterogeneity among participants in terms of both load variability and temperature sensitivity. These characteristics have a meaningful relationship with the accuracy of baselines as was shown by the comparison of baselines (settlement and regression) using the proxy event days.

Load Characterization Recommendations

- Based on these findings, load characterization should be conducted seasonally on all existing participants to be better informed about the overall reliability of estimated load reductions, which could help guide program changes. For example, if at some point too many participants in the program exhibit less than ideal load characteristics, it might be necessary to consider alternative settlement approaches.
- The characterization is straightforward, so a second recommendation is that it might be worthwhile to characterize potential participants as part of a screening process to identify and target particular customers.
- The third recommendation, but one that would require far more substantial changes to the current program or a separate offering, would be for PGE to offer customers with high load variability and/or low weather sensitivity to select a firm service level to achieve, such as with PGE's Firm Load Reduction Pilot Program, rather than a specific amount of load to be shed.

Proxy Event Findings

With respect to the regression baseline modeling and the proxy event day analysis, there were two main findings. The first is that baseline methods can mitigate some of the issues with inaccuracy, but not substantially. The second is that although there were clear cases where one baseline method performed better than another, there are only a few participants where one baseline method was consistently the best across events. The comparison of adjustment factors not only found minimal differences between the additive and multiplicative approaches, but that in a substantial share of cases an unadjusted baseline performed best.

Proxy Event Recommendations

- Our recommendation based on this analysis is that unless there is some substantial change in the composition of program participants, the program can continue with the current settlement baseline with no concerns. While a regression baseline could perform better in some cases, the current settlement baseline's ease of implementation and explanation to participants is the clear advantage.
- The use of a multiplicative adjustment is a feasible change that PGE may wish to consider if it is more comfortable with this baseline adjustment approach, but the analysis showed that it is not going to make a significant difference in the program's estimated impacts or settlements for that matter.

Response Time Findings

Finally, the analysis of response times showed that those participants with automated curtailment not only had higher and more immediate realization rates, but that their impacts had far less uncertainly. This finding is not surprising, but it is an important validation that there are performance issues with manual controls and it highlights the importance of automation.

Response Time Recommendations

- Our recommendation is that PGE should prioritize maximizing participation for sites where automated controls are feasible to improve the certainty of achieving the desired load curtailment within 10 minutes of notification.

ES.2.3 Implementation: Improvements In-Place

Since the program's launch, PGE has continually made program improvements based on customer feedback, discussions with EnerNOC, and the results of evaluation studies. Over the course of the program's first five seasons, the following improvements have been implemented:

- **Bottlenecks in the commissioning process have been removed, thus reducing the timeframe required for enablement.** In previous discussions, customers identified delays in the installation of equipment, but subsequent discussions with EnerNOC staff identified this problem as a scheduling issue and undertook corrective actions. In recent interviews, new customers reported no problems with scheduling the installation visit, and on average reported a two- to three-month timeframe between enrollment and the enablement.

- **PGE now provides a list of pre-selected customers to EnerNOC based on a blind pull of customer load profiles.** To increase enrollment levels, PGE now provides EnerNOC with discrete load profiles to pre-identify potential candidates for participation. This is done in a manner that maintains confidentiality agreements regarding customer data.
- **Dispatchable standby generation customers are now being solicited to participate.** In the past, dispatchable standby generation customers were not solicited to participate, thus reducing the potential for nominated demand in the PGE territory. In May 2015, the program also began pursuing dispatchable standby generation customers. Several large-end users began participating in the fifth season on account of this initiative.
- **PGE incentivizes** Key Customer Managers (**KCMs) for the enrollment of large end-users.** Program growth has been slower than expected, especially among large end-users who offer the most potential for curtailable load. In order to increase enrollment, PGE has also begun providing financial incentives to KCMs who recruit large end-users. A monetary incentive of $1,500 is provided for the recruitment of end-users with 750 kW of load, and a $750 incentive is provided for end-users of 500 kW of load. At the time of this report, one such incentive had been awarded to a KCM.
- **Customers now receive notification to view performance 48 hours after an event.** Some customers lacked the information to determine whether participation was a worthwhile activity. Interviews with customers revealed that they were not checking their performance summary on the EnerNOC portal. The email notification acts as a reminder that they have this option available to them.
- **The time required to process invoices has been reduced, thus allowing faster payment to customers.** Interviews in earlier seasons revealed that customers lacked the payment information required to share and justify the cost-effectiveness of program participation to management. This improvement makes it more likely that customers will have timely access to information regarding payment.
- **The payment formula has been revised to provide greater incentives by rewarding customers for providing capacity rather than hourly performance.** Interviews revealed that some customers have been underwhelmed by the amount of the incentive payment received. The importance of the customer's bottom line should not be underestimated. This action seeks to compensate customers in a manner that justifies the time and effort involved in participation.

ES.2.4 Implementation: Additional Opportunities for Improvement

As the program continues to mature, there are still potential opportunities for further improvement. Most of the following opportunities have already been discussed with PGE:

- **Reach out to customers who have already declined participation.** Some customers have already turned down the opportunity to enroll in the Energy Partner program, but may reconsider participation now that some time has passed. PGE allows EnerNOC to contact customers multiple times, unless the customer is adamantly against further program communications.
- **Coordinate with Energy Trust of Oregon**. PGE views a partnership with Energy Trust of Oregon as a strategic fit that would benefit both parties. PGE will explore developing this relationship in 2016.
- **Expand enrollment to also include customers who can only participate in some program hours.** In the past, only customers who could participate in all program hours were considered for enrollment. As a result, many customers were considered a poor fit for the program and did not receive further consideration. A new strategy would permit customers to enroll if they could just meet some of the program hours (e.g. 2-5 p.m. rather than 2-6 p.m.). This opportunity would provide the program with additional source of nominated demand.
- **Leverage AMI data to reach potential participants.** In past seasons, small end-users with less than <200 kW of load have not been considered a good fit for the program structure. However, creative ways of using AMI data could be used to enable these smaller customers to participate. For example, such customers could participate using AMI data instead of meter data. This type of strategy is still under development, and such candidates have not yet been identified.
- **Fine-tune customer messaging.** PGE marketing studies have shown that while the program offers the right set of marketing messages, the value of these individual messages varies according to the target audience. PGE continues to fine-tune and weigh the importance of various program benefits (e.g., financial incentive, not losing control of the facility, sustainability) according to the role of the target audience.
- **Develop strategic partnerships with control companies and engineering firms.** Firms that design controls or energy management systems are in a unique position to validate the value of program participation. PGE expects to develop strategic relationships with these industry partners, as they play a key role in influencing customer choices.

1

Introduction

Portland General Electric's (PGE) Automated Demand Response (ADR) program, known as the Energy Partner program, enables participants to receive payments for reducing electricity consumption during peak usage periods. Program events may be called at PGE's discretion and typically coincide with peak demand on the electric grid (e.g., hot summer or cold winter days). The program is operated by a third party aggregator, EnerNOC Inc. (EnerNOC), which is responsible for turnkey program implementation. This includes recruiting eligible large non-residential PGE customers, installing curtailment hardware and software, and providing financial settlement services. The program aims to provide a total of 25 MW of peaking capacity to the PGE system by July1, 2017.

The program runs for a three-month period from July 1 through September 30 ("summer period") and for a three-month period from December 1 through the last day of February ("winter period") starting in Summer 2013. During the summer and winter periods, program events may be called: 1) during non-holiday weekdays from 12 p.m. to 10 p.m. Pacific Time for the summer period; and 2) during non-holiday weekdays from 6 a.m. to 11 a.m. and 4 p.m. to 9 p.m. Pacific Time for the winter period.

The program is designed to curtail load on the system during peak periods within 10 minutes of notification. Events are dispatched in one-hour blocks lasting between one and five hours. PGE may dispatch an event to begin at any minute within the available dispatch window. No more than one event may be called in any single day. PGE may not dispatch events for more than two consecutive days or more than 10 days per month during any summer period or winter period. PGE may not dispatch more than 40 hours of events during any summer period of winter period.

1.1.1 Customer Eligibility

Eligible customers include large non-residential customers on the following rate schedules:

- Schedule 89 – Large Non-Residential (> 1,000 kW) Standard Service,
- Schedule 85 – Large Non-Residential (>201 and <1001 kW) Standard Service,
- Schedule 83 – Large Non-Residential Standard Service (>30 and <200 kW),
- Schedule 49 – Large Non-Residential Irrigation and Drainage Pumping, and
- Schedule 47 – Small Non-Residential Irrigation and Drainage Pumping.

Starting in May 2015, distributed generation customers are also eligible to participate in the program.

PGE customers on the following rate schedules are ineligible to participate in the program:

- Schedule 86 – Demand Buy-Back
- Schedule 77 – Curtailment Tariff

Facilities participating in direct access are also ineligible for participation in Energy Partner.

Energy Partner event dispatch is limited to:

- Weekdays (excluding Western Electricity Coordinating Council holidays),
- One-hour blocks (between one and five hours),
- Up to 15 times per season,
- No more than two consecutive days, and
- No more than 40 hours per season.

PGE provides EnerNOC with not less than 10-minute dispatch notice through a direct connection between EnerNOC's systems and PGE's Command Center. Load reduction can be requested by PGE at any time for any time period during which Energy Partner dispatch is allowed.

Some common energy shifting and curtailment strategies include but are not limited to:

- Temporarily shifting non-critical production processes by a few hours,
- Shifting HVAC set points for a short period of time, and
- Adjusting variable frequency drives on pumps or motors for a short period of time.

The amount that a customer is paid is based on the level of participation relative to their nominated demand and varies according to how much energy is shifted and the frequency of events. The customer may override an event at no penalty, but participation is required to receive an incentive.

1.1.2 Evaluation of Program Activities

The Energy Partner program evaluation objectives are:

- Evaluate the load impacts associated with the Energy Partner program,
- Assess customer attitudes concerning their interactions with the third-party aggregator,
- Evaluate the implementation process of program hardware and software installation,
- Assess the customer communications associated with the Energy Partner program, and
- Evaluate the internal efficiency of program operations.

This Phase II report represents the second and last of two evaluation reports to be developed over the pilot period. This report covers the program's first five seasons.

2

Methods

2.1 Impact Analysis

The Phase II impact evaluation consists of the following elements:

A. Verification of program impacts based on the Energy Partner program's prescribed baseline methodology. Itron calculates individual participant Customer Baselines (CBL) and returns the observed event day shape, the baseline shape, and the load impact shape for each individual participant following each event.

   At the conclusion of each season, Itron summarizes all of the individual participants sites' individual event load impacts based on PGE's CBL methodology. Given that these individual impacts are believed to be good estimates[1], Itron believes there is no reason that these would not provide a good estimate of the aggregate impacts. Itron believes that the evidence is clear that using the CBL methodology is a cost-effective, accurate, and unbiased evaluation methodology. In the Phase I evaluation report, Itron recommended that alternative evaluation methods be considered in the future to confirm this assessment. In this evaluation, Itron has used a regression based CBL method to confirm its initial assessment. It also examines an alternative same-day adjustment mechanism.

B. Along with the individual site event load impact calculations, Itron has conducted a billing verification of PGE's implementation contractor, EnerNOC. The implementation contractor provided documentation on billing calculations to be used to verify monthly bills. Itron verified these calculations and provided PGE with site-specific recommendations for dispute. This activity is not the focus of this report and will not be discussed in any further detail.

There are several methods that can be used to quantify the load effects of the Energy Partner program. The key issue is how to derive the individual and aggregate baseline loads on event days from which the load curtailment can be estimated. A number of research studies in the past decade

[1] Based on prior research noted later.

have examined these CBL methodologies. The most prominent have been KEMA 2003,[2] Quantum 2004,[3] Quantum 2006,[4] LBNL 2008,[5] and KEMA 2011.[6]

The LBNL 2008 study built upon the earlier works and may well be the gold standard of CBL evaluations. This study found that a CBL methodology (simple average over the highest five out of 10 previous admissible days with morning adjustment), virtually the same as the one to be used for settlement purposes by the PGE Energy Partner program, had nearly the lowest bias and highest accuracy of any other methodology studied. The only other methodology that performed better was the regression-based approach as it captures load response to weather the best, but a regression-based approach is not very practical for continuous settlement purposes. Regression-based approaches are appropriate for program evaluation purposes.

The CBL methodology for the Energy Partner program has minor differences from that used in the LBNL study. These differences include: 1) using a morning adjustment based on the average usage of the three-hour period ending three hours prior to the start of the event period, instead of the average usage of the two hours immediately prior to the start of the event; and 2) an adjustment factor that is additive rather than multiplicative. The first difference should have minimal effect since the Energy Partner program is a day-of DR program with between 10 minutes and three hours notification, making gaming difficult. The second difference has been found in other studies to be of little significance.

Considering this, it appears that not only is the Energy Partner CBL methodology a solid choice for financial settlement purposes, it is also a good choice to use to evaluate the impacts of the program. As a result, Itron believes that, <u>as the base evaluation methodology</u>, the Energy Partner CBL methodology should be used to estimate the load impacts for each individual participant in the program in this report. Itron, after the fourth season, recommended that a regression-based

2 Goldberg M.L and G. Kennedy Agnew 2003. *Protocol Development for Demand-Response calculations: Findings and Recommendations.* Prepared for the California Energy Commission by KEMA-Xenergy. CEC 400-02-017F.

3 Working *Group 2 Demand Response Program Evaluation – Program Year 2004 Final Report*. Prepared for the Working Group 2 Measurement and Evaluation Committee, by Quantum Consulting Inc. and Summit Blue Consulting, LLC, 2004.

4 *Evaluation of 2005 Statewide Large Nonresidential Day-ahead and Reliability Demand Response Programs*. Prepared for Southern California Edison and the Working Group 2 Measurement and Evaluation Committee, by Quantum Consulting Inc. and Summit Blue Consulting, LLC, 2006.

5 Coughlin, K., M.A. Piette, C. Goldman, and S. Kiliccote 2008. *Estimating Demand Response Load Impacts: Evaluation of Baseline Load Models for Non-Residential Buildings in California*. Prepared for the California Energy Commission, by Demand Response Research Center, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-63728. http://emp.lbl.gov/sites/all/files/REPORT%20lbnl%20-%2063728.pdf

6 *PJM Empirical Analysis of Demand Response Baseline Methods.* Prepared for the PJM Markets Implementation Committee, by KEMA, Inc., April 20, 2011.

approach be implemented to confirm the accuracy of the Energy Partner CBL. PGE accepted this recommendation and the results from this analysis are included in this Phase II report.

2.2 Additional Load Analyses

In addition to the load impact analysis, the evaluation team conducted four supplemental load analyses for the Phase II report.

These additional tasks include:

- **Participant Load Characterization**: A classification of participant sites based on load variability and weather sensitivity.
- **Regression Baseline Modeling**: The use of statistical models to develop participant baselines as an alternative to PGE's "5 highest of 10 days with morning adjustment" methodology, which is the current baseline used for settlement.
- **Proxy Event Analysis**: The use of proxy event days to compare the accuracy and bias of different baseline methodologies.
- **Curtailment Response Speed Analysis**: An analysis of the degree to which participants are able to meet their curtailment targets quickly at the start of events.

More detailed descriptions of these tasks will be presented in their respective sections, but all of them relied on at least one of the following data sources:

- **Load Data**: Five-minute interval kWh by account number (PODID) from PGE's operations group. This particular set of data was used over the other sources because it covered the most extensive range of dates and accounts compared to the other sources. A summary of the number of participants in each program season, along with summaries of hourly kWh and counts of non-holiday weekdays, is presented in Table 2-1.
- **Weather Data**: Hourly temperature readings for Portland International Airport acquired from www.wunderground.com. These data were converted to five-minute readings using linear interpolation.
- **Enrollment and Event Information**: Enrollment and committed load reduction by participant from EnerNoc's monthly enrollment reports. The event information (date, notification time, and event start and end times) were compiled from numerous sources, including invoices and some email confirmations.
- **Participant Control Type**: Information on the type of control (manual versus automatic) employed at the participant sites, which was provided by EnerNOC.

Table 2-1: Summary of Available Interval Data by Program Season

Program Season	Participants	Hourly kW			Days of Data		
		Min	Mean	Max	Min	Mean	Max
Summer 2013	2	448	717	987	36	46	55
Winter 2013/2104	3	138	475	828	56	56	56
Summer 2014	16	108	508	1,192	58	58	58
Winter 2014/2015	36	109	402	2,382	40	40	40
Summer 2015	46	120	500	2,738	61	61	61

2.2.1 Participant Load Characterization

The purpose of this task is to characterize the program's participants in terms of the variability and temperature sensitivity of their load. The only meaningful disadvantage of using PGE's ADR CBL methodology for evaluating the impacts of the program is that this baseline load profile methodology typically will not perform well for customers with high levels of load variability and/or low levels of weather sensitivity. As no CBL methods will perform well for these customers, it is important to have some sense of how many of the programs participants do not lend themselves to reliable estimation of impacts using the settlement baseline.

This characterization of load variability and weather sensitivity are based on two metrics used by Lawrence Berkeley National Laboratories (LBNL) in a 2008 paper. The load variability for each participant is based on the average absolute percent deviation for each interval. The data used in the calculations included only non-holiday, non-event weekdays and only hours during the program's availability window for the season in question. For each participant, each five-minute interval's load was subtracted from that interval's average load for all available data for the season in question. The absolute value of the deviation was then converted to a percentage by dividing by the period average and then an average of these absolute percent deviations was calculate for each interval. Each participant's final variability metric was based on the average of this metric across all intervals. This metric is always positive and low numbers indicate less variability.

The weather sensitivity for each participant is determined by using the Spearman Rank Order Correlation (ROC[7]). This robust type of correlation, which looks at the relationship between the ranked order of temperature and usage, is preferable to the standard Pearson correlation because it gives equal weight the pairings. The ROCs were first calculated by participant, season, and five-minute interval and were based on the same subset of data used in the calculation of load variability. The final metric of weather sensitivity for a participant and season was based on the average ROC across all intervals. The separate calculation for each interval was used to avoid the influence of any spurious association due to hours of operation or manufacturing cycle. These

7 https://statistics.laerd.com/statistical-guides/spearmans-rank-order-correlation-statistical-guide.php

ROC values can range from -1.0, which indicates a perfect negative relationship, and 1.0, which indicates a perfect positive relationship.

2.2.2 Regression Baseline Modeling

As an alternative to the PGE's settlement baseline, Itron estimated baselines at the participant and event level using regression analysis using the following model specification:

$$
\begin{aligned}
Load_t = \beta 1 &+ \sum_{i=2}^{288} (\beta 2_i \times B_i) \\
&+ \sum_{i=1}^{96} \sum_{dt=2}^{5} \left(\beta 3_{dt,i} \times DType_{dt,t}\right) + \sum_{i=1}^{96} (\beta 4_i \times B_i \times HDH_t) + \sum_{i=1}^{96} (\beta 5_i \times B_i \\
&\times CDH_t) + \sum_{DR=1}^{E} \sum_{i=1}^{96} \left(\beta 6_{i,DR} \times B_i \times ADR_{DR,t}\right) + \epsilon_t
\end{aligned}
$$

Where:

> $Load_t$ represents a vector of observations on interval usage for a participants,
> B_i is a set of binary time variables that are 1 in interval i and 0 otherwise,
> $DType_{dt,\,t}$ is a set of day-type variables set to 1 on a specific day type and 0 otherwise,
> HDH_t is a cooling degree hour variable,[8]
> CDH_t is a cooling degree hour variable,
> $ADR_{Evt,\,t}$ is a set of binary variables set to 1 on an ADR event day and 0 otherwise,
> $\beta 1$, $\beta 2i$, $\beta 3_{dt,i}$, $\beta 4_{m,i}$, $\beta 5_i$, and $\beta 6_{i,DR}$ are unknown parameters to be estimated, and
> ϵ_t is the error term.

Two key factors that can vary are the amount of data used in estimation and the level of aggregation of the interval data. With the respect to the former, including more days of data to estimate the models might result in more accurate baselines, but could be more difficult to employ operationally due to the additional data and processing requirements. The level of aggregation is relevant because there might be noise in the five-minute interval data that is eliminated via aggregation, which could lead to overall better models. Itron estimated models using 30, 60, and 90 days of data for intervals of five minutes, 15 minutes, and one hour. After review of the results, the models used for reporting in this memo were based on 60 days of data using the five minute intervals.

8 Heating degree hours are typically defined as the maximum between zero and the difference between the average temperature for a given hour and a base temperature (AveT – Base). The base is a reference temperature for cooling, such as 50 degrees Fahrenheit. Alternative base temperatures can be used. Customer specific HDH values will be developed using data from the closest weather station to each participant.

2.2.3 Proxy Event Baseline Analysis

The comparison different baseline approaches (regression versus settlement, different adjustment approaches) using actual events has limited value. Without some sense of whether one approach is "better" compared to the others, it is difficult to ascribe much meaning to the results. As a means of assessing the different approaches, a proxy event analysis was conducted for five days using the data from Season 5 (Summer 2015). In addition to having the most participants and most completed data, season five also many non-event hot days, which is essential to replicate event-like conditions.

The selection of the proxy event days was based on the five hottest non-event weekdays in terms of daily maximum temperature. The proxy event days are representative of the weather conditions on typical event days. Baselines were estimated for these proxy event days using the settlement baseline approach and the regression model described previously. The method for the settlement baseline's additive adjustment was applied to both baselines approaches. Additionally, a multiplicative adjustment was calculated as an alternative the additive.

The assessment of the baselines was based on calculating the percent error ([actual kWh - baseline kWh] / actual kWh) and its absolute value in each interval during the availability window for each proxy event and participant. The percent error being a measure of bias and the absolute percent error being a measure of accuracy.

2.2.4 Curtailment Response Speed Analysis

For the final supplemental task, Itron analyzed the response speed of program participants for the season five events. The analysis was based on calculating the degree to which each participant achieves its nominated load shed over each event interval. The five-minute intervals are not sufficient to determine exactly how immediately participants respond to events, but do help to determine if they have fully responded within the 10-minute requirement.

Of particular interest in this analysis is the sites' types of curtailment controls, which for this analysis have been divided into those sites with manual controls and those with automated controls.

Itron's analysis is primarily visual and it looked at response times in two ways. The first view considers the participants in the aggregate and compare their collective impacts to the total nominated load curtailment to develop realization rates in each interval. Given that there is uncertainty in the individual impacts, this approach assumes that the errors generally even out and it provides a view of how quickly the overall population of participants respond to events.

The second view looks at the individual participants' response speed relative to the average. This approach is intended to reveal how much variation there is in response speed among the participants. This analysis examines more closely the differences between sites with manual versus automated controls.

2.3 In-Depth Interviews

The evaluation team conducted discussions with various program actors to characterize the key issues pertaining to the PGE Energy Partner program. Interviews were conducted with program participants (new and continuing participants), PGE program staff, PGE account managers, EnerNOC staff, and staff at Energy Trust of Oregon (Energy Trust). The number of interviews conducted with each program actor is presented in Table 2-2. The following subsections describe the nature of each of these discussions in greater detail.

Table 2-2: Overview of Interviews with Program Actors

Program Actor	Round One (After Season 2)	Round Two (After Season 3)	Round Three (After Season 4)	Round Four (After Season 5)
Participants	3	11	18	20
New	3	8	9	3
Continuing	-	3	9	17
PGE Program Staff	1	1	0	1
PGE Key Customer Managers	-	2	-	-
EnerNOC	1	1	0	1
Energy Trust of Oregon	-	-	-	2

2.3.1 Discussions with Program Participants

After each season, the evaluation team made an effort to conduct interviews with all new and continuing participants. In some cases, however, not all customer contacts were able to be reached. New customers were asked to characterize their experiences with the decision to enroll, the enablement process, curtailment events, notification, the payment process, customer satisfaction and any topics of interest, such as the ability to curtail with a 10-minute notification period. Continuing participants had a similar, but abbreviated interview that aimed to identify any changes in participation status and to monitor improvements in program implementation.

2.3.2 Discussions with PGE Program Staff

On three occasions, the evaluation team conducted in-depth interviews with PGE program staff members. These discussions focused on the enablement process, curtailment events, event notification, the payment process, and other topics of interest. The first interview was conducted with three PGE staff members (program evaluation, program manager, and marketing), while the second and third interviews were conducted with two different staff members (product development, load research and program evaluation) as a result of a staff change at PGE.

2.3.3 Discussions with PGE Key Customer Managers

Interviews with Key Customer Managers (KCMs) were not planned as part of the original evaluation plan, but after the second season, KCMs were asked to provide their perspective on customer recruitment. In addition to their duties as utility account managers, KCMs initiate program discussions with customers and formally refer them to EnerNOC. Two KCMs were interviewed as part of this evaluation.

2.3.4 Discussions with Program Implementer (EnerNOC)

The evaluation team conducted in-depth interviews with the EnerNOC program manager on three occasions to characterize and monitor the program's rollout and development. The framework of these discussions focused on the outreach approach, the customer decision-making process, the commissioning process, experience with curtailment events, and the payment process.

2.3.5 Discussions with Energy Trust of Oregon

During the course of the evaluation of the PGE Energy Partner program, several customers reported that their decision to participate was influenced by activities associated with Energy Trust. To follow up on these reports, Itron conducted interviews with two Energy Trust staff members after Season 5. The interviews explored Energy Trust's role in introducing demand response programs to customers and how Energy Trust and the Energy Partner Program might collaborate in the future.

3

Load Analysis

This Load Analysis section of the Energy Partner Phase II Evaluation report discusses a) the event impacts over Seasons 1 through 5, and b) the supplemental load analyses that were performed to gain insight into the participants and the performance of the program.

3.1 Summary of Event Impacts

This section summarizes the Energy Partner event impacts for Season 1 through Season 5. Seasons 1, 3, and 5 were summer seasons and Season 2 and 4 were winter seasons. The impacts presented are the verified load impacts resulting from the evaluation.

3.1.1 Season 1 Event Results

In the first season, the summer of 2013, the Energy Partner program called three events. These are summarized in Table 3-1. The program was successful in meeting its nominated load for all the events.

Table 3-1: Season 1 Events Summary

Event Date	Event Hours	Peak Event Day Temp.	Number of Participants	Nominated Load (kW)	Average Hourly Impact (kW)	Realization Rate
8/6/2013	4-6 p.m.	91º F	2	250	540	216%
8/21/2013	3-6 p.m.	90º F	2	250	347	139%
9/11/2013	4-7 p.m.	95º F	2	250	387	155%

Figure 3-1 through Figure 3-3 show the aggregate of the individual participant baselines and actual loads on each of the Season 1 events. They also show the sum of the individual calculated impacts next to the aggregate nominated load. It is necessary to keep in mind that the desirable impacts are shown as positive. It is also important to keep in mind that on an individual participant basis, the difference between the baseline and actual load is made zero if the difference is negative in the settlement calculations; i.e., the actual load is higher than the baseline load. This has the effect in the aggregate of showing a positive impact when the aggregate baseline and actual load suggest otherwise. All the graphs have been adjusted to show the event impacts as the simple subtraction of the adjusted baseline minus the actual event day loads. This helps to reveal any event snapback effects that may be occurring.

Figure 3-1: August 6, 2013 Aggregate Event Impact

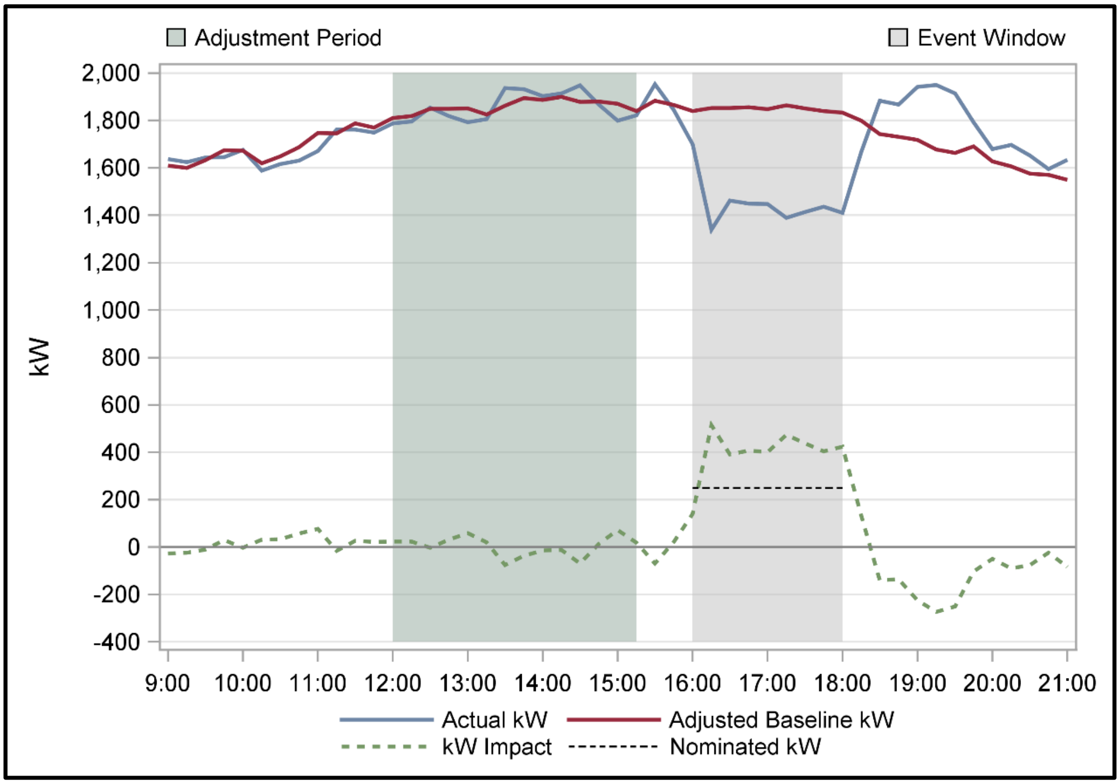


Figure 3-2: August 21, 2013 Aggregate Event Impact

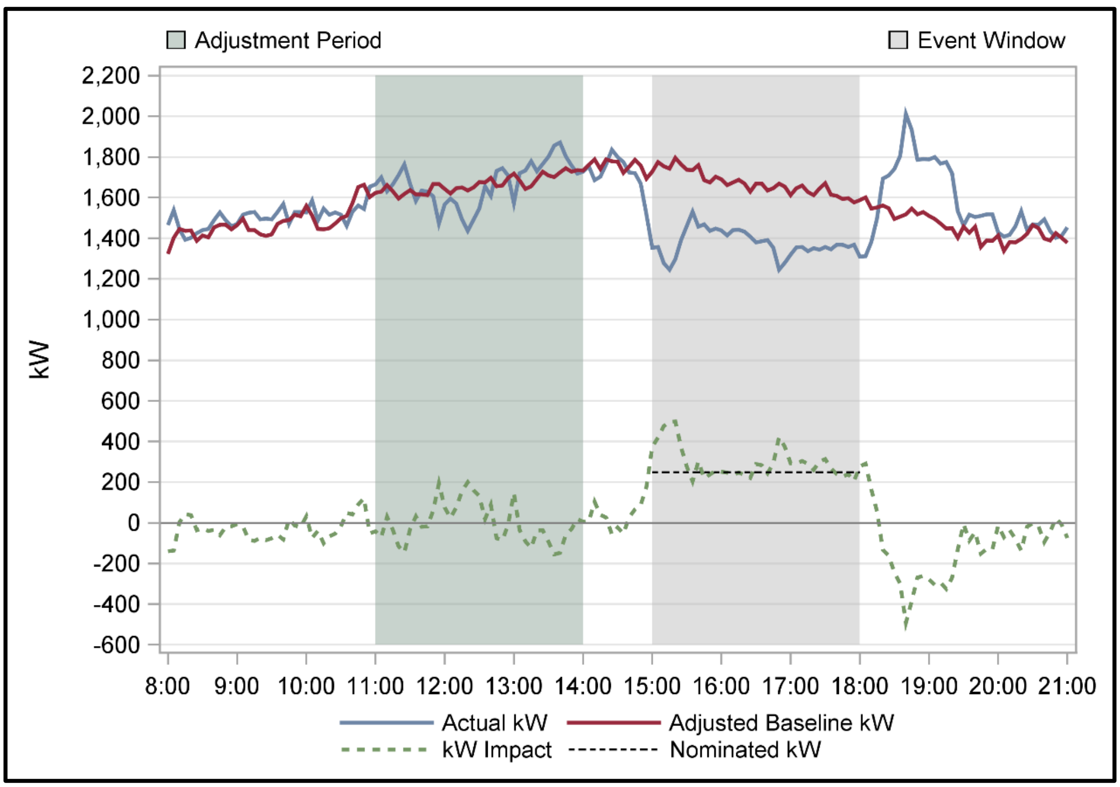
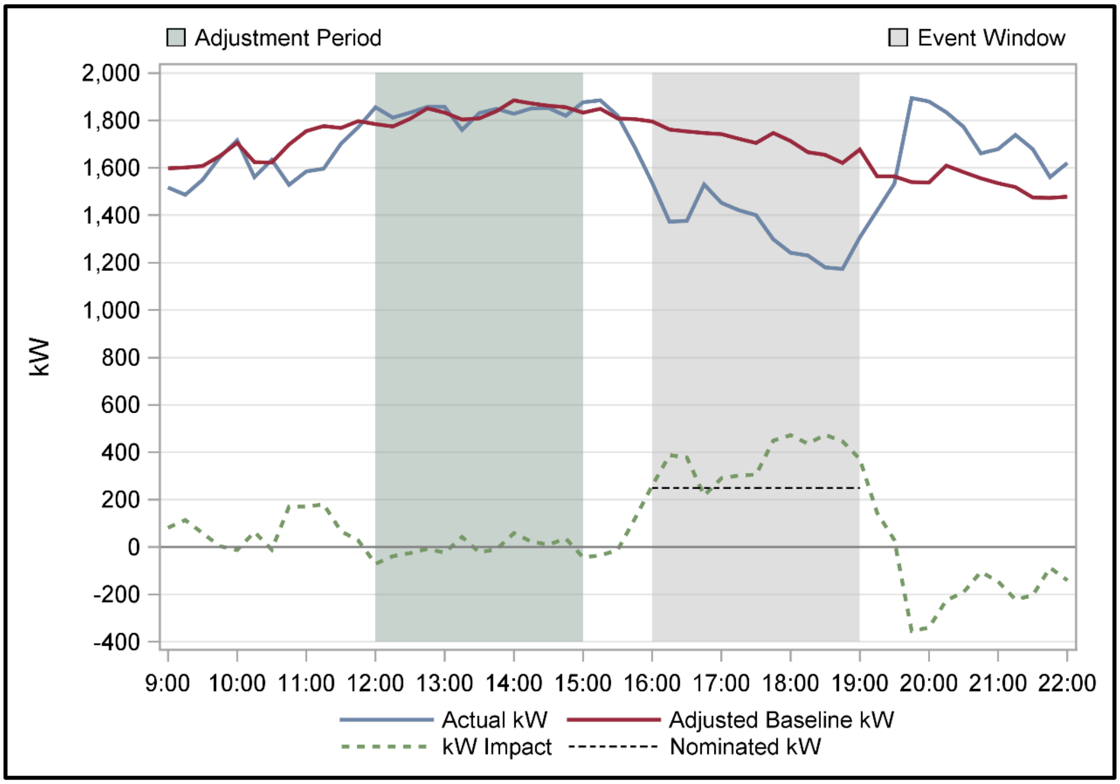


Figure 3-3: September 11, 2013 Aggregate Event Impact



3.1.2 Season 2 Event Results

Season 2 was the first winter season for the Energy Partner program. Season 2 had five events called in total: three in December and two in February. These are summarized in Table 3-2. The last two events in December were called on consecutive days as were the two in February. The December 9 event was called for the morning whereas the December 10 event was called for the afternoon. Both of the February events were called in the afternoon. The program was successful in meeting its nominated load for the first three events but not the last two. The two customers who had been enrolled in the prior season did not perform as well in February as they had in December. There is no obvious explanation for this lower performance as their demand did not change significantly between December and February. The newest participant was barely able to contribute during the February events due to their operating hours not being within the afternoon event window.

Table 3-2: Season 2 Events Summary

Event Date	Event Hours	Peak Event Day Temp.	Number of Participants	Nominated Load (kW)	Average Hourly Impact (kW)	Realization Rate
12/5/2013	5-8 p.m.	32º F	2	150	216	144%
12/9/2013	7-9 a.m.	29º F	2	150	338	225%
12/10/2013	6-8 p.m.	34º F	2	150	316	211%
2/5/2014	4-6 p.m.	29º F	3	300	283	94%
2/6/2014	4-6 p.m.	23º F	3	300	262	87%

Figure 3-4 through Figure 3-8 show the aggregate of the individual participant baselines and actual loads on each of the Season 2 events as well as the sum of the individual calculated impacts.

Figure 3-4: December 5, 2013 Aggregate Event Impact

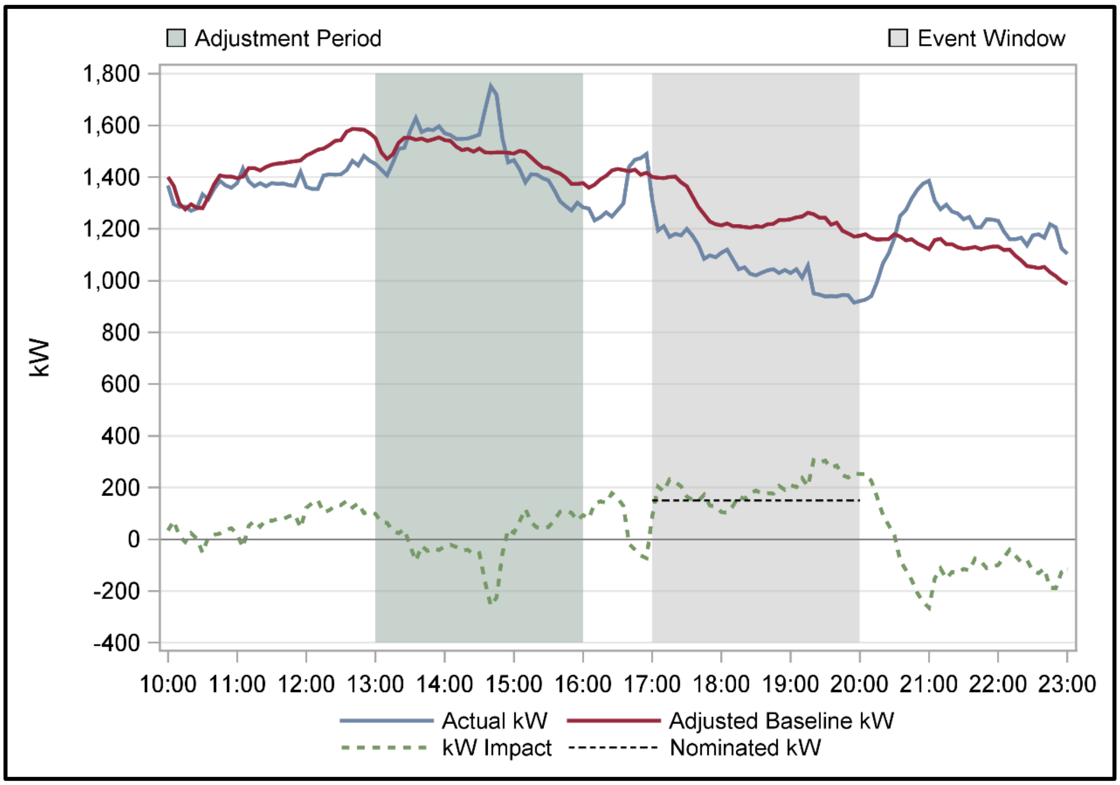


Figure 3-5: December 9, 2013 Aggregate Event Impact

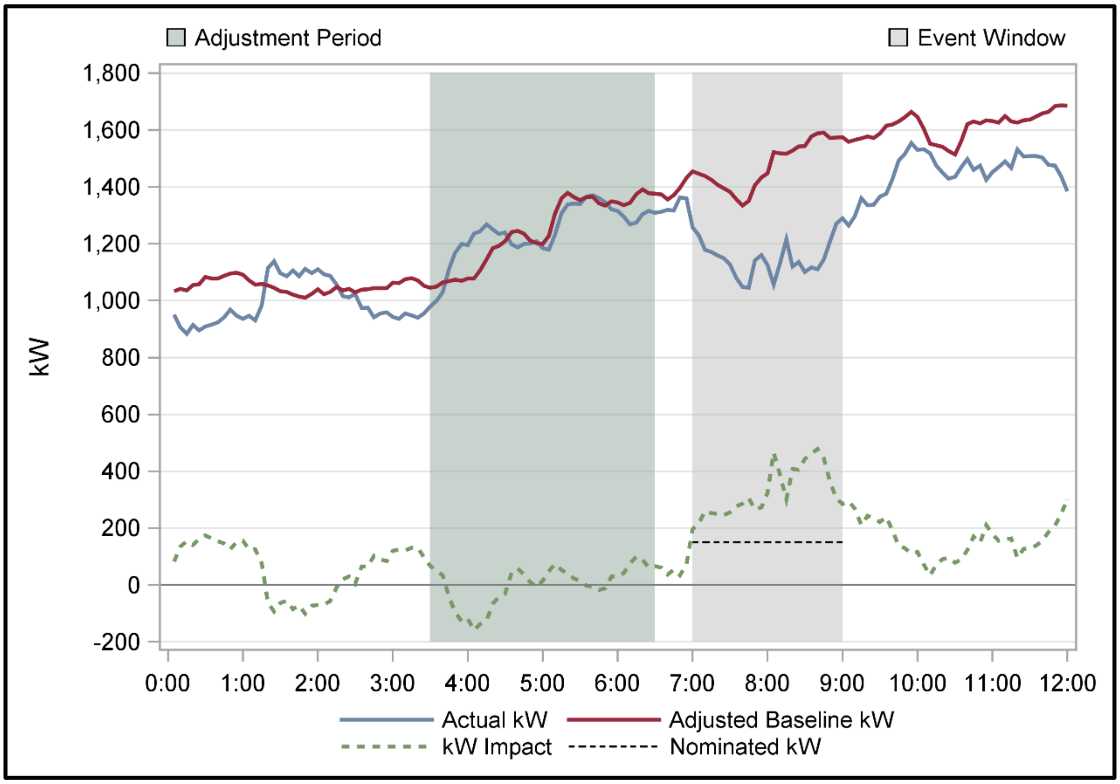


Figure 3-6: December 10, 2013 Aggregate Event Impact

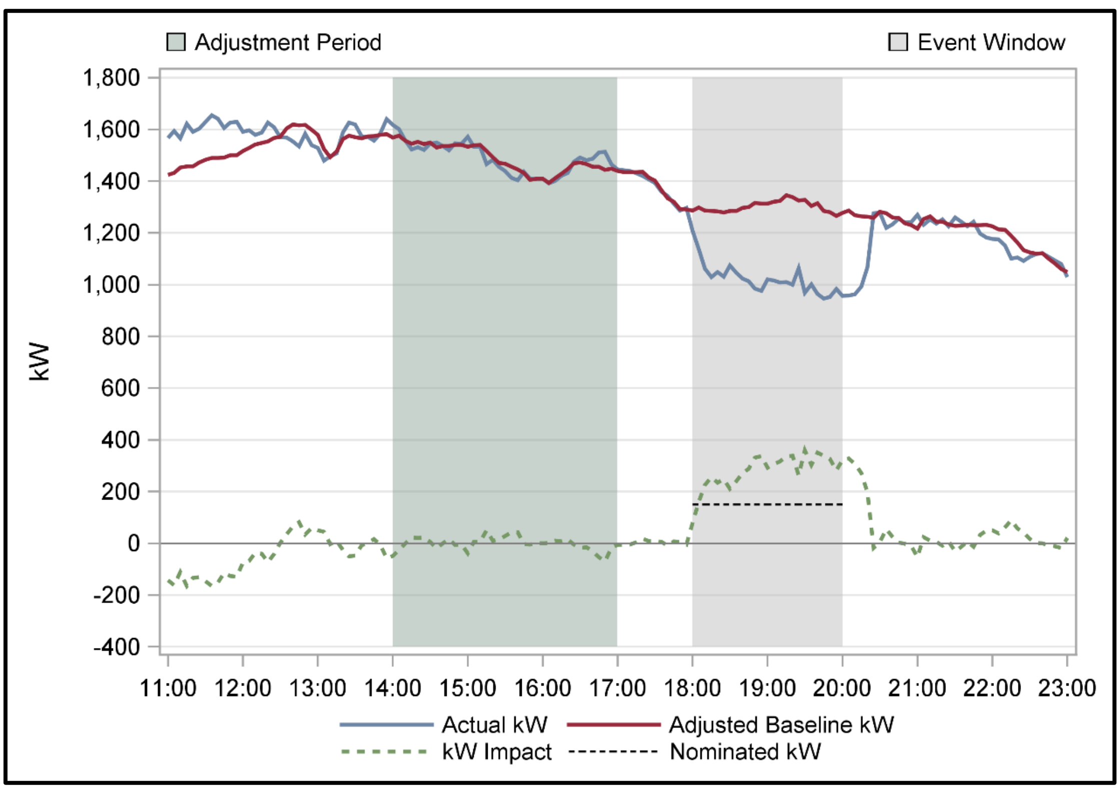


Figure 3-7: February 5, 2014 Aggregate Event Impact

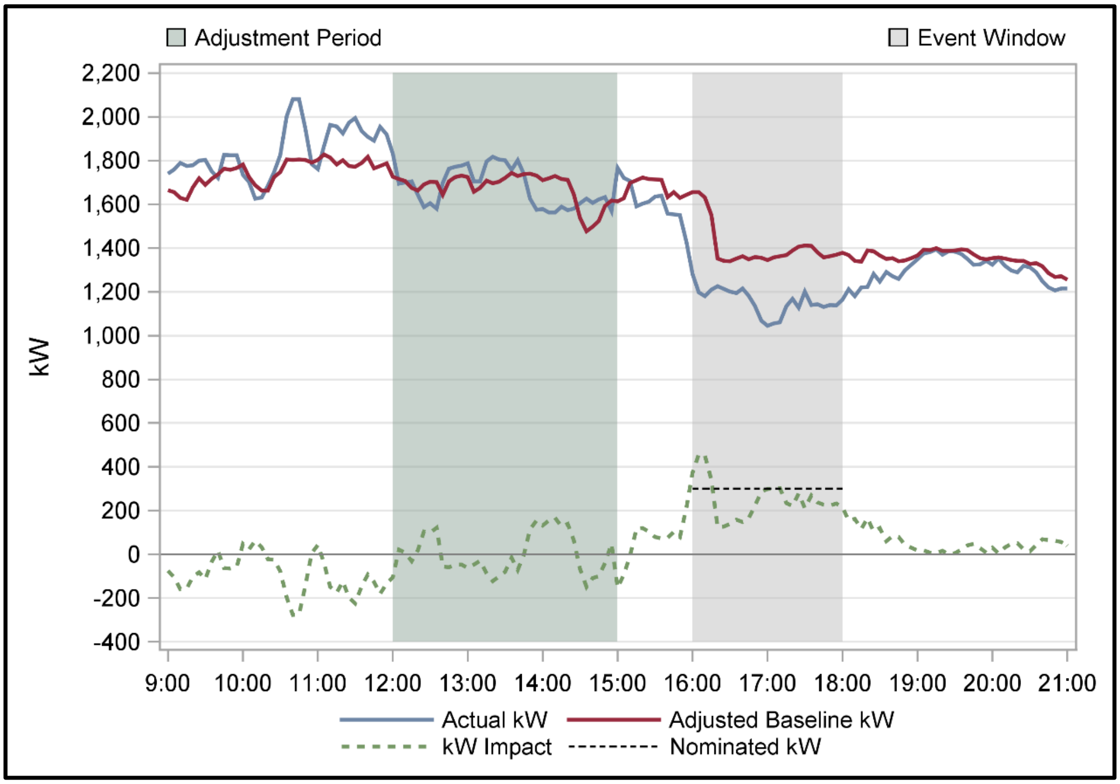
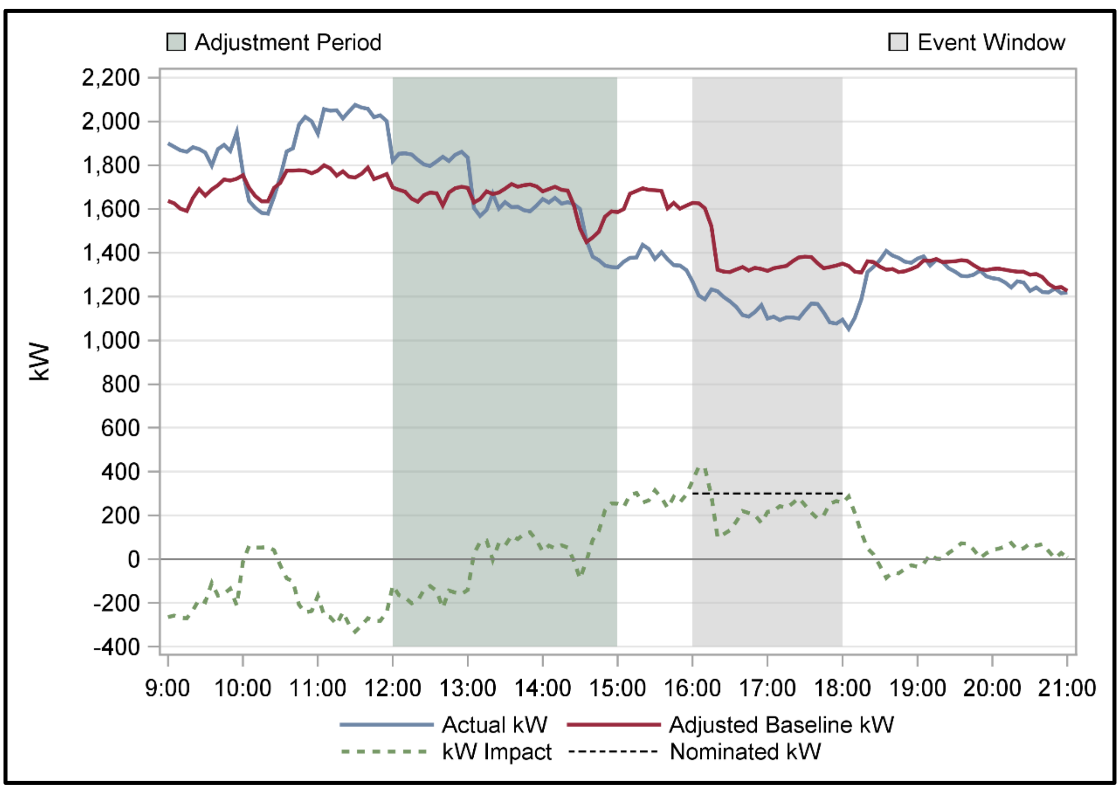


Figure 3-8: February 6, 2014 Aggregate Event Impact



3.1.3 Season 3 Event Results

Season 3 saw a significant increase in the number of participants and the nominated load compared to Season 2. Season 3 had six events called, five of which were called in July alone. These are summarized in Table 3-3. Even though the enrollment increased in August by an additional four participants, the nominated load was decreased by EnerNOC and the actual load impacts on an individual customer-basis decreased as well. The program was successful in meeting its nominated load on four of the six events. During this season, three new participants were added in the second month (August), but a few of the individual participants' nominated loads were adjusted downward lowering the overall nominated load for the portfolio for August.

At first glance, the July event performance appears to be correlated to temperature; as the peak temperature declined and then increased with successive events, the impacts followed the same trend. However, the load levels just prior to the start of the first three July events were all virtually the same suggesting that the loads may not be very weather sensitive. The overall aggregate load levels during the last two events of the season saw a significant increase. In the future, a thorough analysis of the characteristics and drivers of the participants' load levels is recommended as it may reveal further details to inform the program design for greater performance.

Table 3-3: Season 3 Events Summary

Event Date	Event Hours	Peak Event Day Temp.	Number of Participants	Nominated Load (kW)	Average Hourly Impact (kW)	Realization Rate
7/1/2014	4-6 p.m.	99º F	13	2,695	2,942	109%
7/8/2014	4-6 p.m.	88º F	13	2,695	2,624	97%
7/14/2014	3-7 p.m.	85º F	13	2,695	1,187	44%
7/28/2014	4-6 p.m.	92º F	13	2,695	2,373	88%
7/31/2014	2-6 p.m.	91º F	13	2,695	3,560	132%
8/26/2014	4-8 p.m.	93º F	17	2,520	3,009	119%

Figure 3-9 through Figure 3-14 show the aggregate impacts for each of the summer events in Season 3. The July 14 event had a considerably lower impact than the other events during this season. It was the third event in just two weeks right at the beginning of this season. According to PGE staff, some customers reported "event fatigue" during this timeframe, even though no such issues were mentioned by customers when interviewed several months later. Another reason that performance on July 14 event failed to meet expectations is that two water authorities could not curtail, likely due to minimum water level requirements.

Figure 3-9: July 1, 2014 Aggregate Event Impact

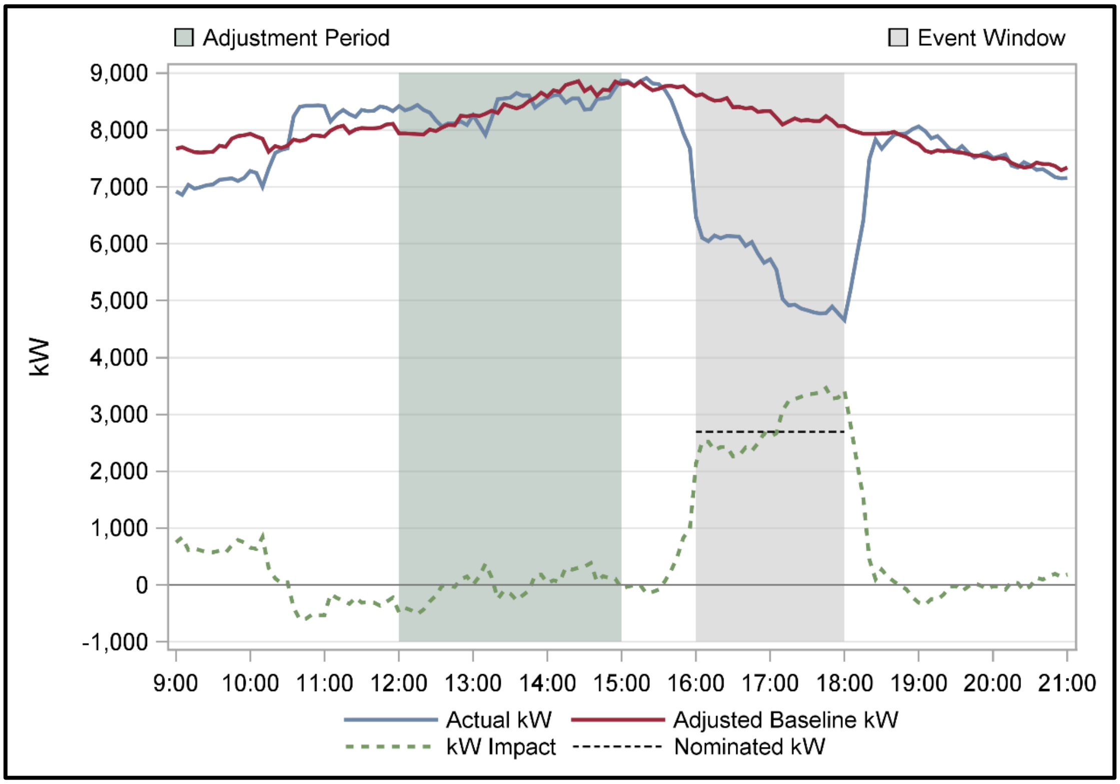


Figure 3-10: July 8, 2014 Aggregate Event Impact

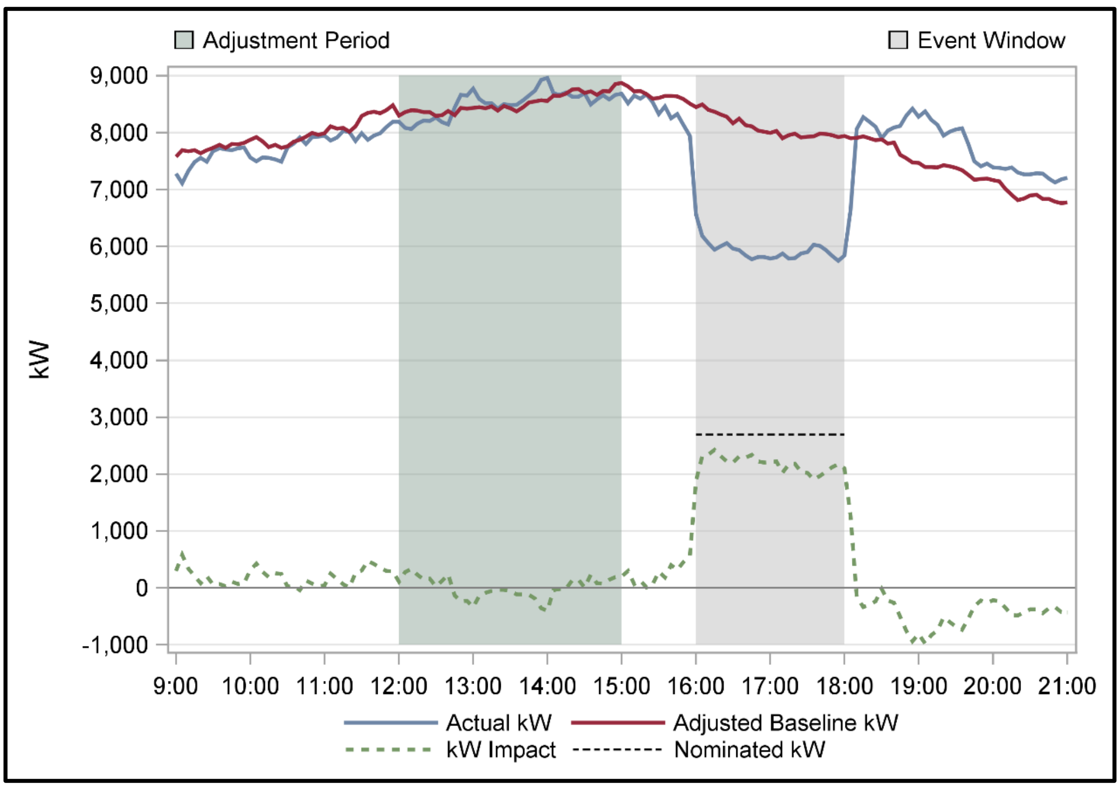


Figure 3-11: July 14, 2014 Aggregate Event Impact

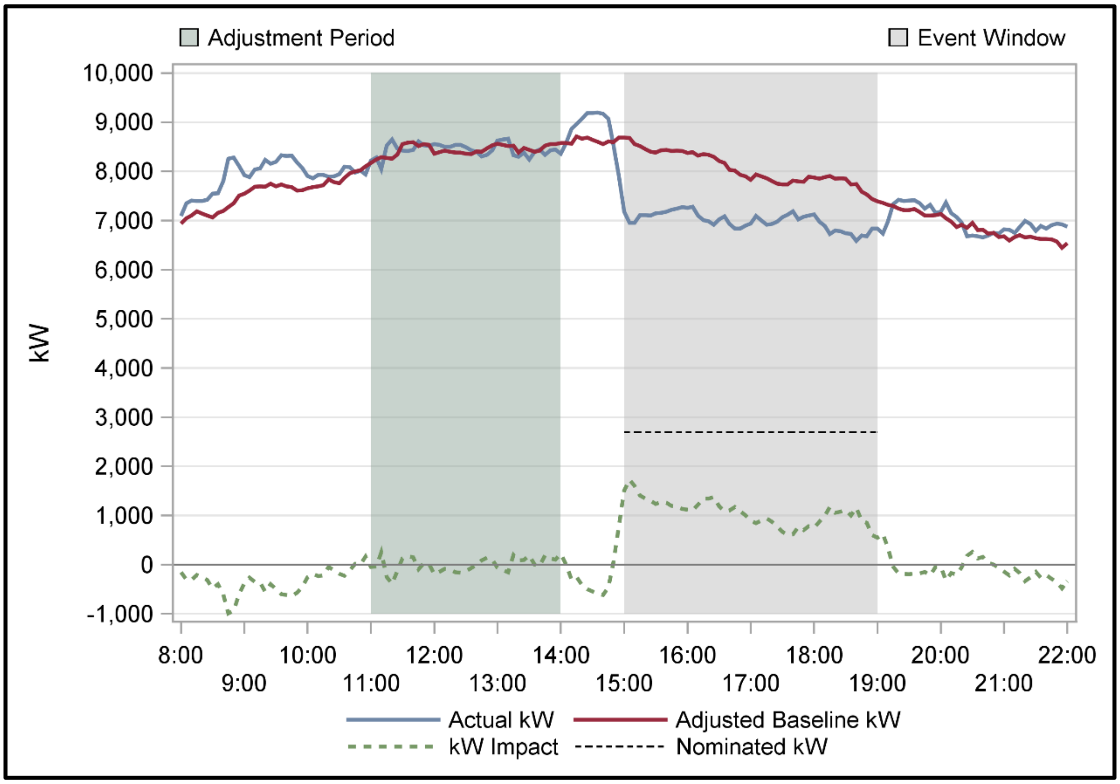


Figure 3-12: July 28, 2014 Aggregate Event Impact

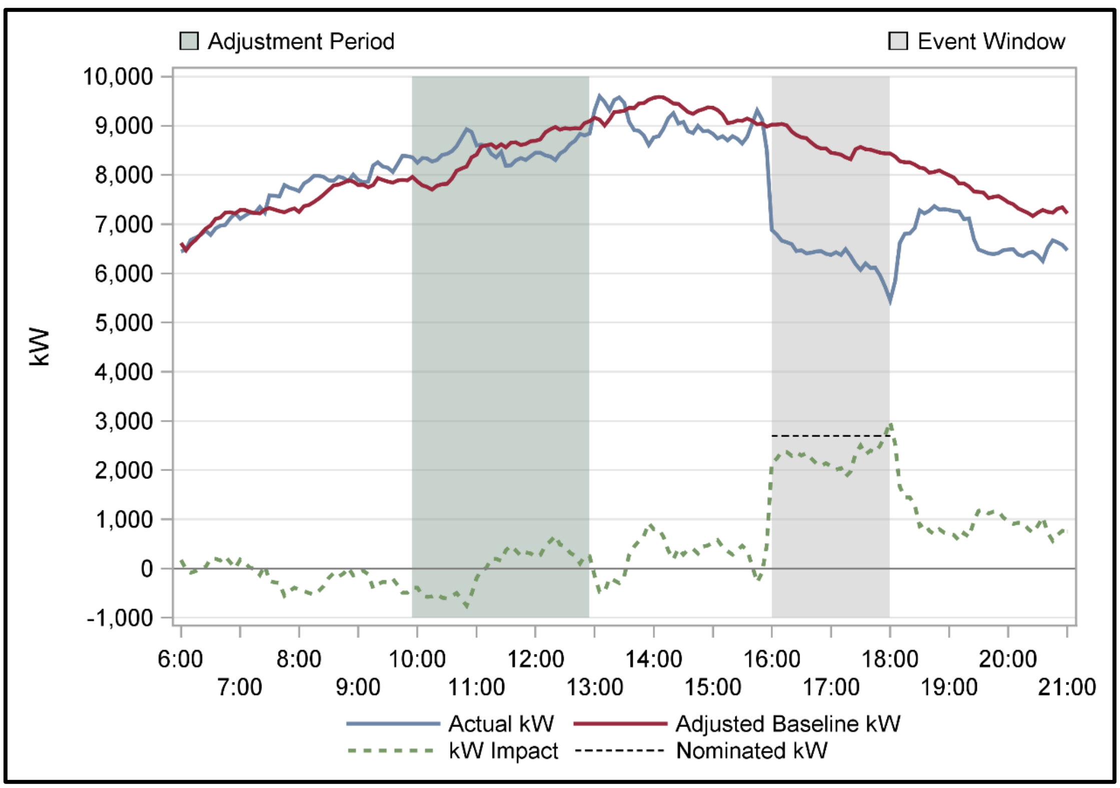


Figure 3-13: July 31, 2014 Aggregate Event Impact

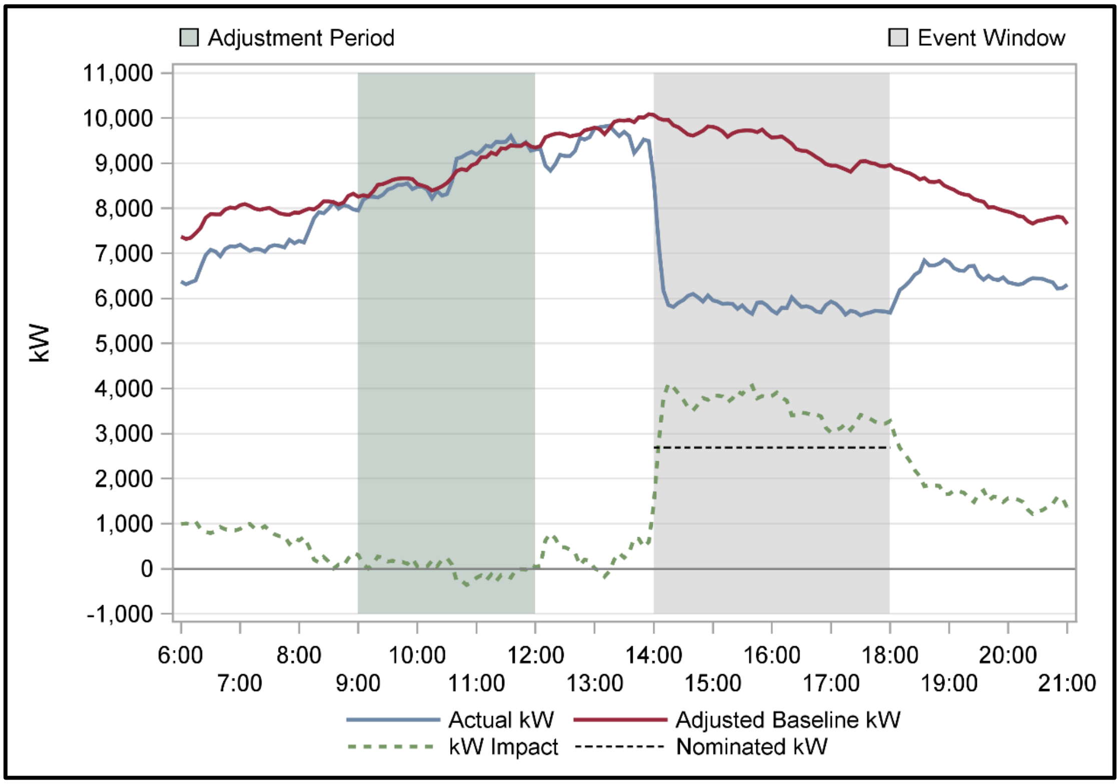
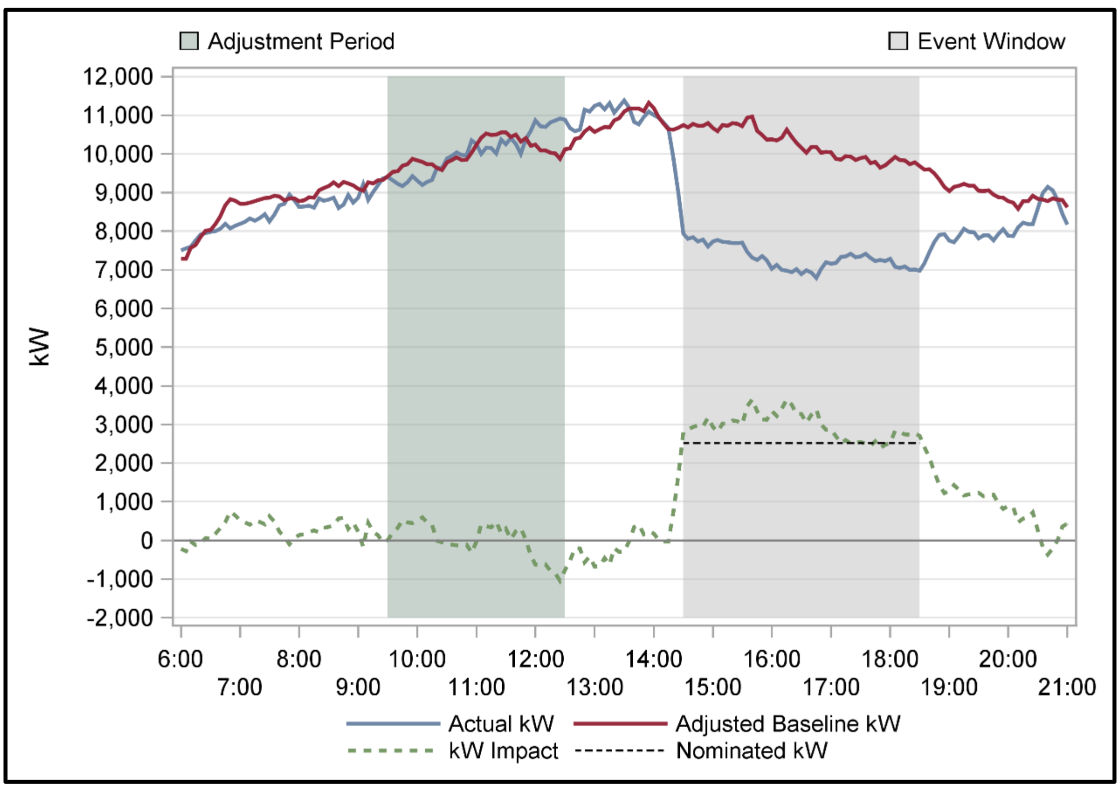


Figure 3-14: August 26, 2014 Aggregate Event Impact



3.1.4 Season 4 Event Results

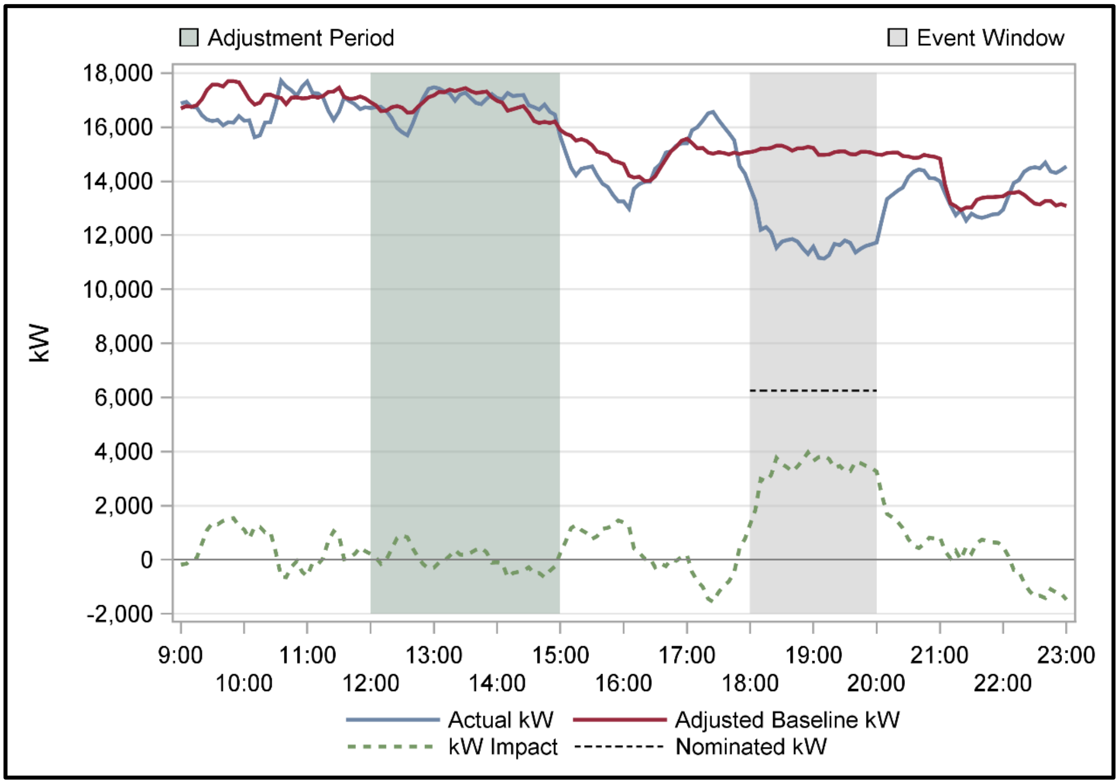
In Season 4, the enrollment for the program doubled since the end of Season 3. Only one event was called and this was on December 30. The realized load shed was only 68% of the nominated load. This low performance may be partially a result of the day falling between Christmas and New Year. Table 3-4 summarizes this single event in Season 4.

Table 3-4: Season 4 Events Summary

Event Date	Event Hours	Peak Event Day Temp.	Number of Participants	Nominated Load (kW)	Average Hourly Impact (kW)	Realization Rate
12/30/2015	6-8 p.m.	34	37	6,260	4,243	68%

The aggregate adjusted baseline load profile and the aggregate actual load profile for this single event day is shown graphically Figure 3-15.

Figure 3-15: December 30, 2014 Aggregate Event Impact



3.1.5 Season 5 Event Results

The enrollment in Season 5 increased significantly over the previous season. Four events were called during this summer season and the weighted realized load shed was 86% of the nominated load. A summary of the events for Season 5 is presented in Table 3-5 along with graphical illustrations of the event days in Figure 3-16 through Figure 3-19.

Table 3-5: Season 5 Events Summary

Event Date	Event Hours	Peak Event Day Temp.	Number of Participants	Nominated Load (kW)	Average Hourly Impact (kW)	Realization Rate
7/1/2015	3-7 p.m.	95	45	7,785	7,107	91%
7/2/2015	3-7 p.m.	97	45	7,785	7,431	95%
7/30/2015	3-7 p.m.	103	45	7,760	6,148	79%
8/12/2015	4-8 p.m.	91	46	9,205	7,404	80%

Figure 3-16: July 1, 2015 Aggregate Event Impact

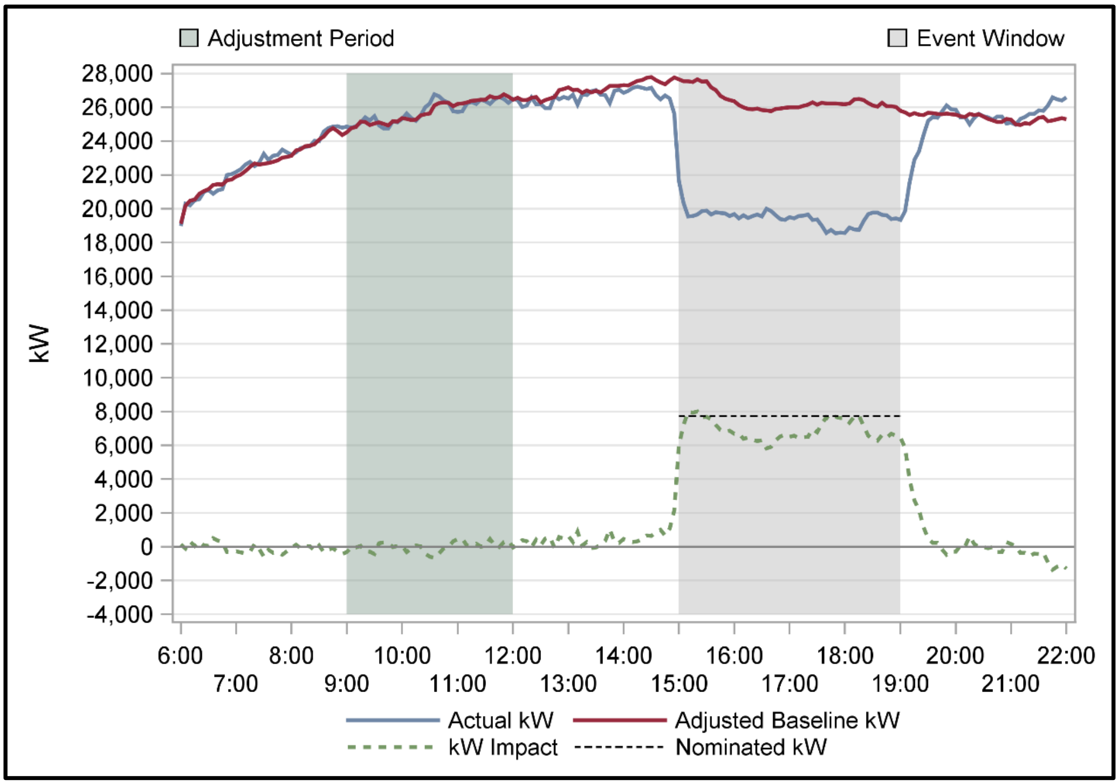


Figure 3-17: July 2, 2015 Aggregate Event Impact

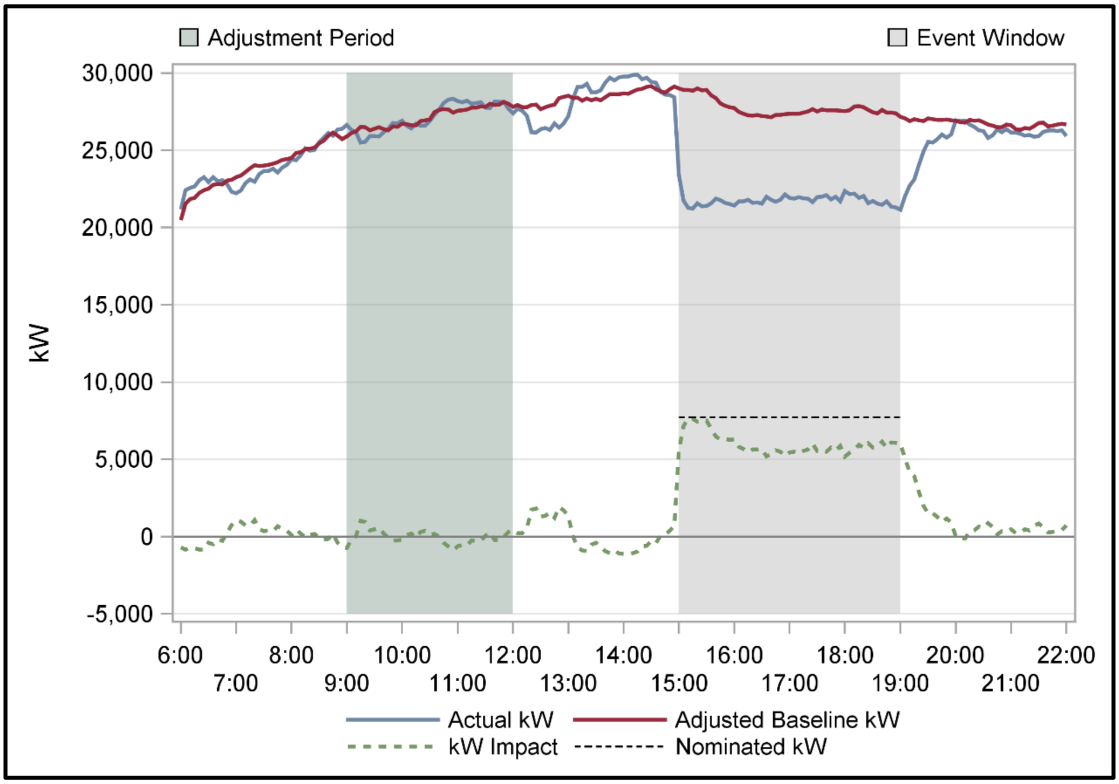


Figure 3-18: July 30, 2015 Aggregate Event Impact

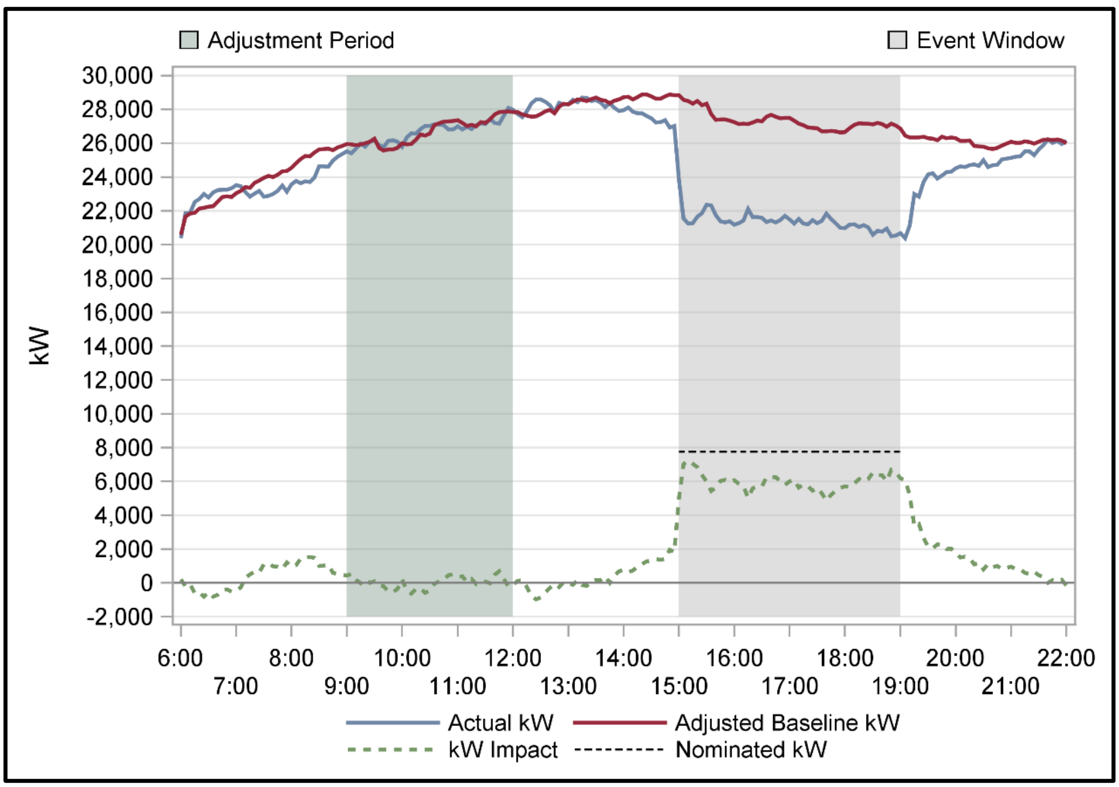
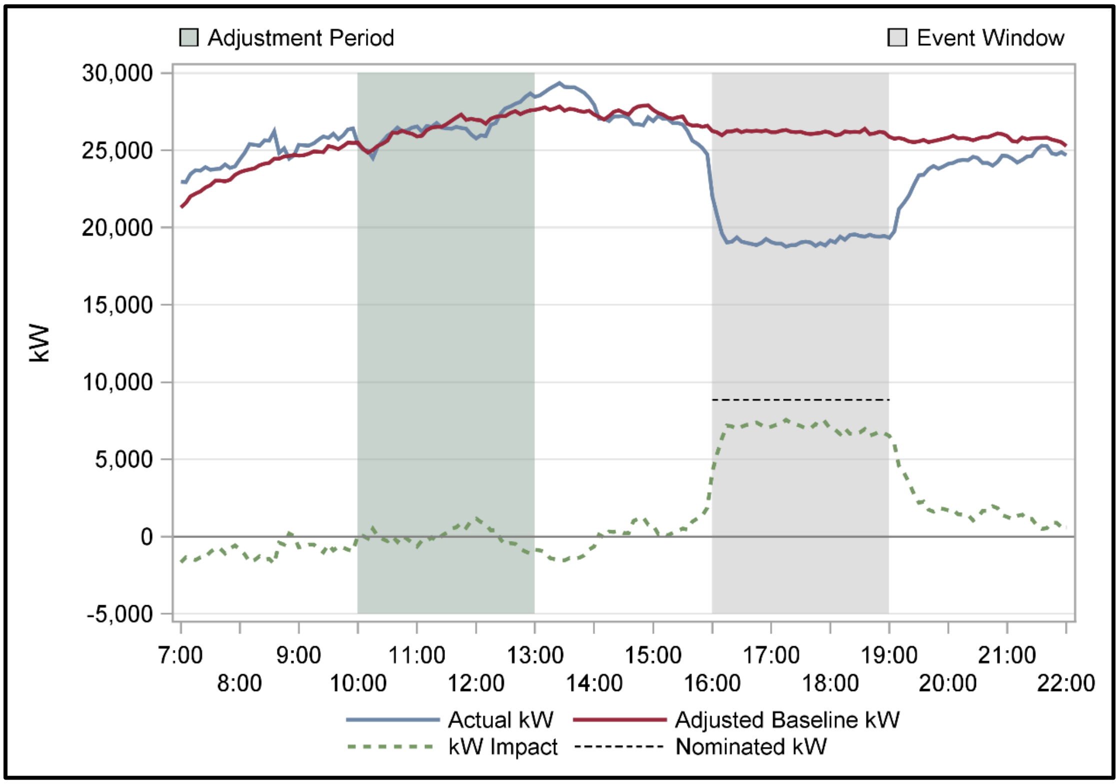


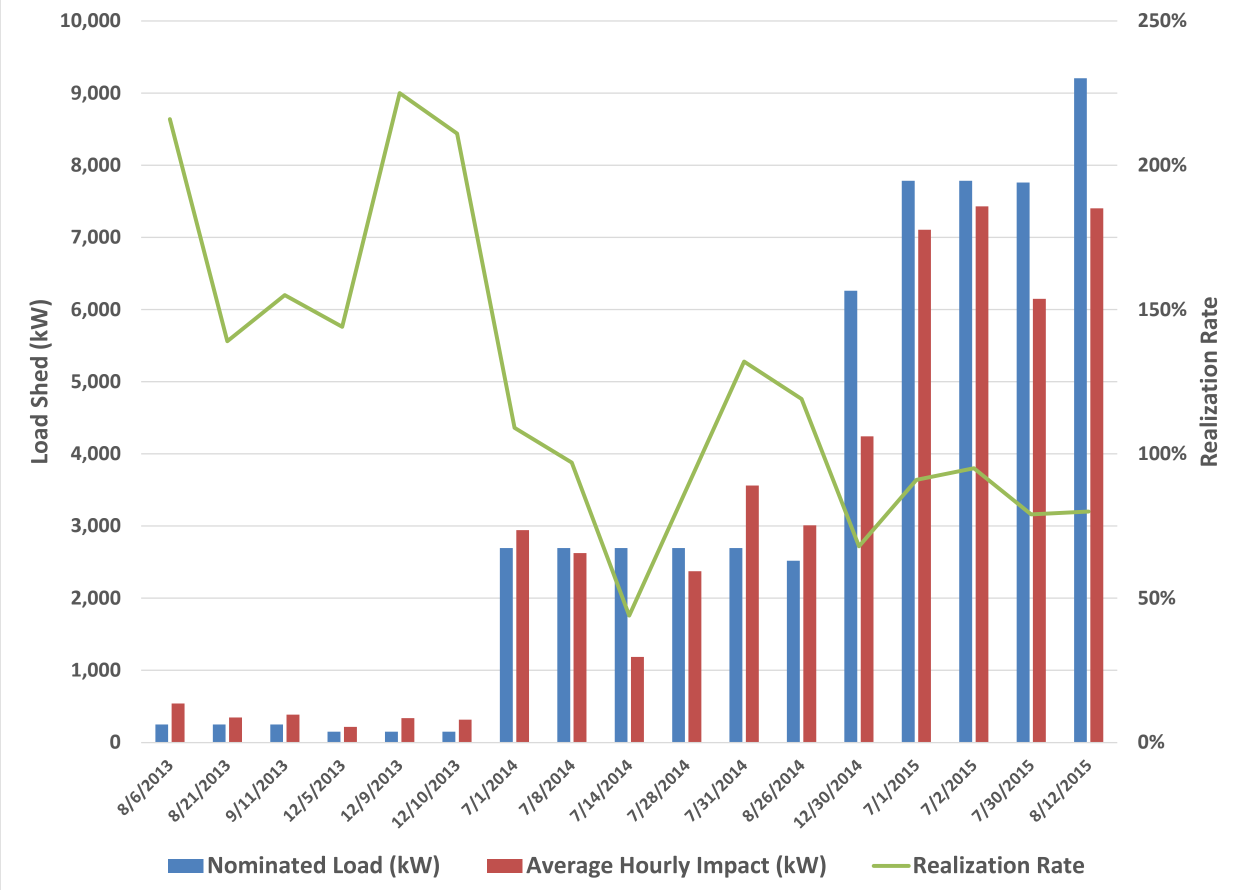
Figure 3-19: August 12, 2015 Aggregate Event Impact



3.1.6 Overview of Performance Results

The Energy Partner program's performance trend can be seen in Figure 3-20. The nominated load and actual load shed has increased over time. The realization rate of the impacts has declined over this period, but it appears to be leveling out. This is a function of the maturity of the program and number of customers enrolled. The performance should begin to stabilize due to the diversity that comes with increased enrollment and due to participants learning how they can respond. The supplemental analyses described in the next section will provide further insight into the performance of the program.

Figure 3-20: Load Shed Performance—Season 1 through Season 5



3.2 Supplemental Load Analyses

This section provides a summary of the results for four supplemental analyses conducted as part of the Impact Measurement and Verification of the ADR program. These additional tasks include:

- Participant Load Characterization,
- Regression Baseline Modeling,
- Proxy Event Analysis, and
- Curtailment Response Speed Analysis.

The findings from these analyses are presented in their respective sections below.

3.2.1 Participant Load Characterization

In the Phase I report, Itron discussed how the variability of the loads within the event window across the weekdays of a season have implications on how accurate the calculated baselines will be at representing the load in the absence of an Energy Partner event. Figure 3-21 shows one customer's (Customer A) actual load on the July 31, 2014 event, their adjusted baseline, and the difference between the actual and baseline or the load impact. The shaded area on the left side is the window in which the adjustment factor for the baseline is determined. The shaded area on the right is the event window. In this case, the baseline appears to be a good representation of what the load would have been during the event window had an event not be called. Customer A's coefficient of variation (CV) for the event window across the season is 8%. Figure 3-22 shows the load profiles for the days that contributed to the baseline load profile. As depicted by the graph, there is some variability about the unadjusted baseline, but in general, the contributing days are very similar to the resulting baseline.

Figure 3-21: Customer A: July 31, 2014 Baseline, Actual, and Difference

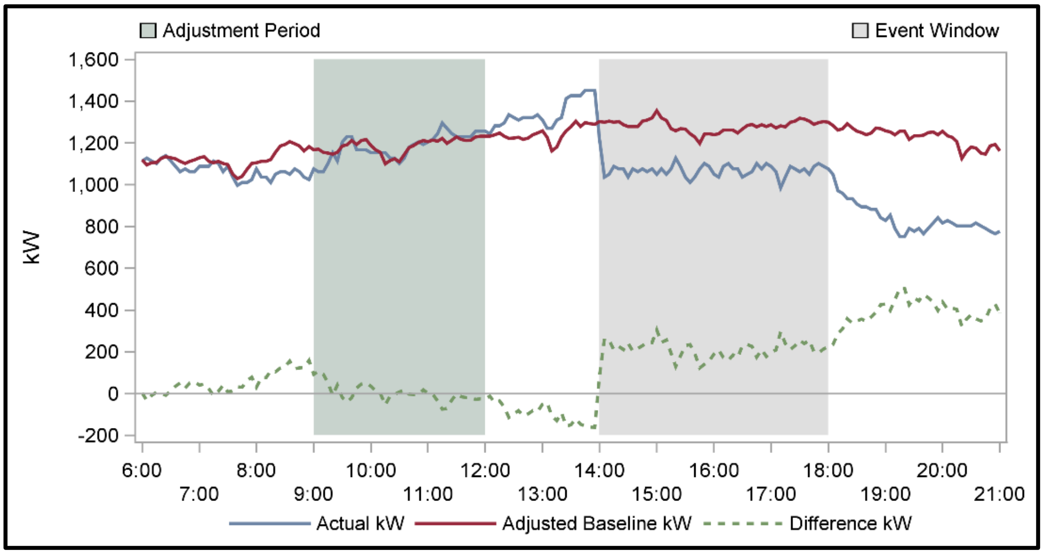
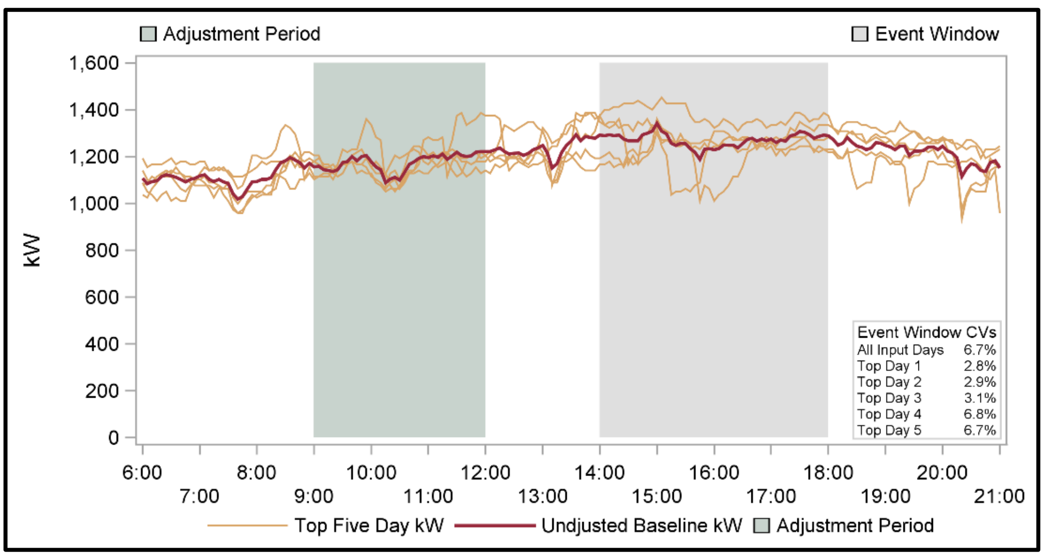
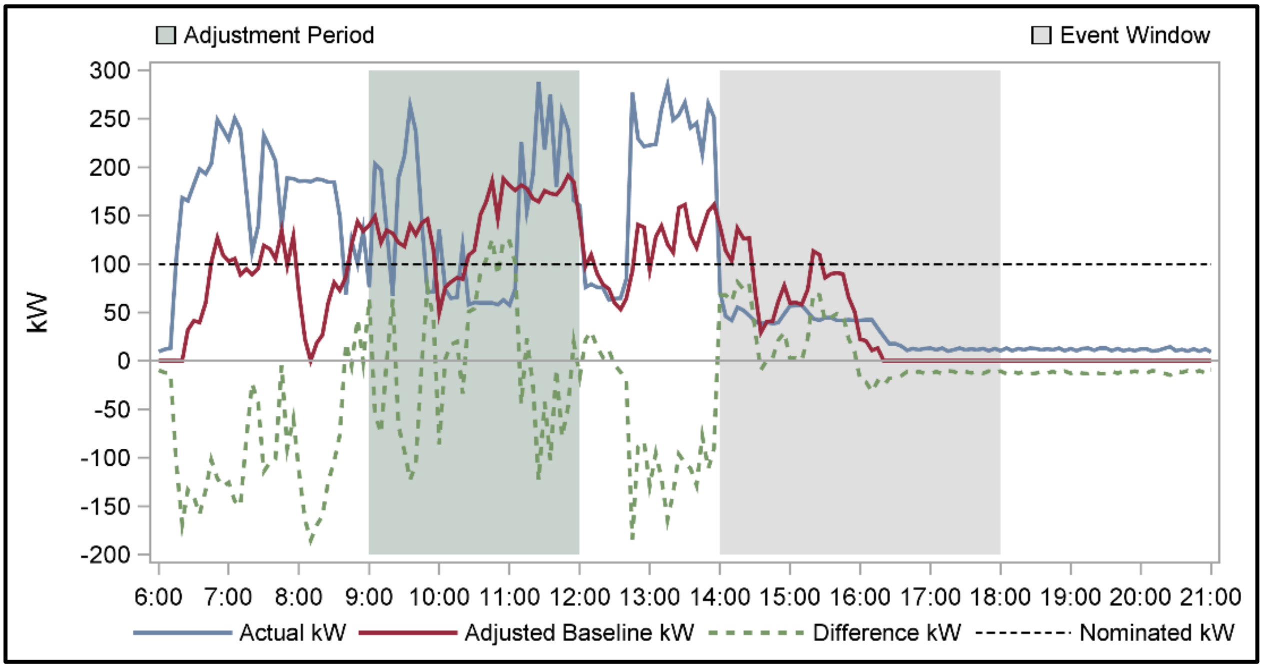


Figure 3-22: Customer A: July 31, 2014 Baseline and Contributor Load Profiles



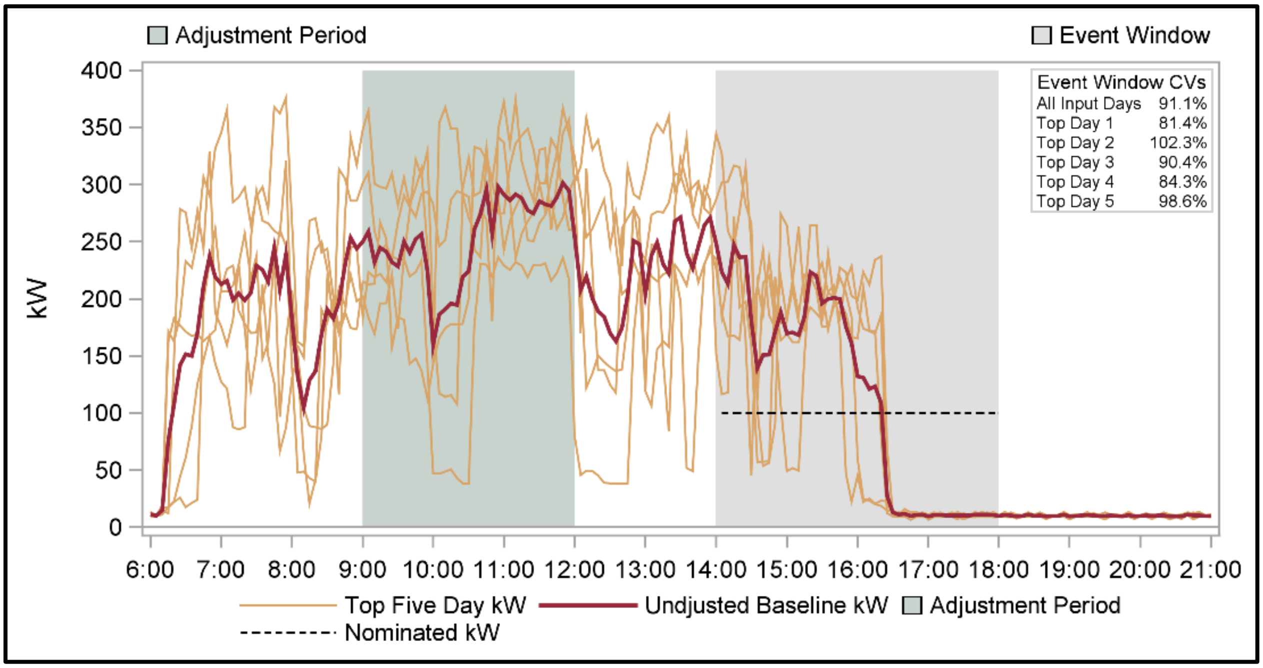
In contrast, Figure 3-23 shows the adjusted baseline, the actual load, and the load impact for another participant (Customer B). In this case, the load is volatile, but there is a pattern to it that the adjusted baseline has capture to some extent. Figure 3-24 shows the load profiles that contributed to this participant's baseline. It is clear that this customer's loads are very irregular and the baseline estimate may or may not be a good representation of what the customer's load would have been had an event not been called. These two graphs also show how the load volatility can result in an adjusted baseline that has negative values. One could conclude that this customer is not a good candidate for this program just on the basis of the volatility of their load, not to mention that they appear not to operate at a significant level for much of the time during the event window.

Figure 3-23: Customer B*: July 31, 2014 Baseline, Actual, and Difference



* Customer is no longer in the program.

Figure 3-24: Customer B: July 31, 2014 Baseline and Contributor Load Profiles



The Load Characterization supplemental analysis in this Phase II report takes a closer look at characterizing customer load volatility. The purpose of this task is to characterize the program's participants in terms of the load variability and temperature sensitivity of their load. The load variability for each participant is based on the average absolute percent deviation for each interval. Specifically, for each participant, the mean absolute percent deviation is calculated separately for each interval in the availability window (12:00 PM to 10:00 PM) for all of non-holiday weekdays in season 5 that were not actual events. The final variability metric is the mean of these mean absolute percent deviations, so they can range from zero on upwards, with larger values indicating higher variability.

The temperature sensitivity for each participant is determined by using the Spearman Rank Order Correlation (ROC). Again, these are calculated separately for each interval and the final metric is based on the mean of the individual interval ROCs. These two metrics were chosen because of they have been used in other baseline evaluation studies.[1]

The variability and the temperature sensitivity characterization was conducted separately for all five of the program seasons, but the main body of this report examines only Season 5, which had the highest participation and the most complete set of data with which to conduct the analysis

[1] Coughlin, K., M.A. Piette, C. Goldman, and S. Kiliccote 2008. *Estimating Demand Response Load Impacts: Evaluation of Baseline Load Models for Non-Residential Buildings in California*. Prepared for the California Energy Commission, by Demand Response Research Center, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-63728. http://emp.lbl.gov/sites/all/files/REPORT%20lbnl%20-%2063728.pdf

(see Table 3-6). The 46 participants reflect those presented in EnerNoc's final invoice for August 2015.

After calculating both variability and temperature sensitivity metrics, the participants were assigned to three separate and roughly equal-sized groups for each metric to indicate "Low," "Medium," or "High." It is important to clarify that these classifications are not based on any objective criteria for what constitutes "high" or "low." That is, the designation of "high" means that the participant exhibited high variability or temperature sensitivity relative to the other participants, but it does not necessarily have meaning in an objective sense. In spite of this, it is evident that for both metrics there was sufficient variability among participants to lend meaning to these groups. Table 3-6 provides a cross tabulation of the minimum, mean, and maximum values for the metrics by temperature sensitivity and variability group, with the bottom row providing a summary for all 46 participants. The range from minimum to maximum shows substantial variation. For example, the ROC that measures temperature sensitivity ranges from a low of -0.2, which indicates a small and negative relationship with temperatures, to a high of 0.940, which shows an almost perfect relationship between temperatures and load. Likewise, the metric for load variability ranges from 2.7% to 110%. Closer examination of the table provides additional evidence that the metrics and the group classifications are likely meaningful characterizations of the participants–such as the substantial difference in the group mean values for both metrics–but this will become more evident as these groups are incorporated into the other analysis tasks.

Table 3-6: Summary of Variability and Temperature Sensitivity Metrics

Variability Group	Temperature Sensitivity Group	Number of Participants	Load Variability			Temperature Sensitivity (ROC)		
			Min	Mean	Max	Min	Mean	Max
High	**Medium**	6	18.5%	31.0%	50.7%	0.216	0.421	0.570
	Low	9	18.3%	40.3%	111.0%	-0.200	-0.019	0.185
	All	15	18.3%	36.6%	111.0%	-0.200	0.157	0.570
Medium	**High**	8	10.6%	11.6%	12.7%	0.594	0.783	0.940
	Medium	5	9.4%	12.5%	16.4%	0.379	0.424	0.556
	Low	3	12.5%	15.3%	18.1%	-0.158	-0.036	0.063
	All	16	9.4%	12.5%	18.1%	-0.158	0.517	0.940
Low	**High**	7	4.4%	6.5%	8.5%	0.688	0.745	0.807
	Medium	5	2.7%	7.2%	9.3%	0.209	0.423	0.572
	Low	3	4.1%	6.5%	8.2%	-0.112	0.015	0.163
	All	15	2.7%	6.7%	9.3%	-0.112	0.492	0.807
All	**High**	15	4.4%	9.2%	12.7%	0.594	0.765	0.940
	Medium	16	2.7%	17.8%	50.7%	0.209	0.422	0.572
	Low	15	4.1%	28.6%	111.0%	-0.200	-0.016	0.185
	All	46	2.7%	18.5%	111.0%	-0.200	0.391	0.940

While the tabular summary in Table 3-6 provides an overall sense of how the groups differ, data visualization can help to depict what these groups mean in terms of the load characteristics for individual participants. Figure 3-25 through Figure 3-28 present load average load profiles for four participants in different variability and temperature sensitivity groups. The average load is surrounded by an inner band indicating the interquartile range of observations (the 25th to 75th percentiles) and an outer band showing the 10th and 90th percentiles. Figure 3-25 depicts the load for a participant with high variability and medium temperature sensitivity (there was no participant "high" in both groups). The bands associated with the two percentile ranges give a good idea of what high variability means; throughout the availability window the values associated with the 10th and 90th percentiles are roughly 30% to 50% different from the mean. The temperature sensitivity is not as easy to discern, but there is a fairly steady increase in the load during the afternoon hours when temperatures rise.

Figure 3-25: Load Profile for Participant with High Variability and Medium Temperature Sensitivity

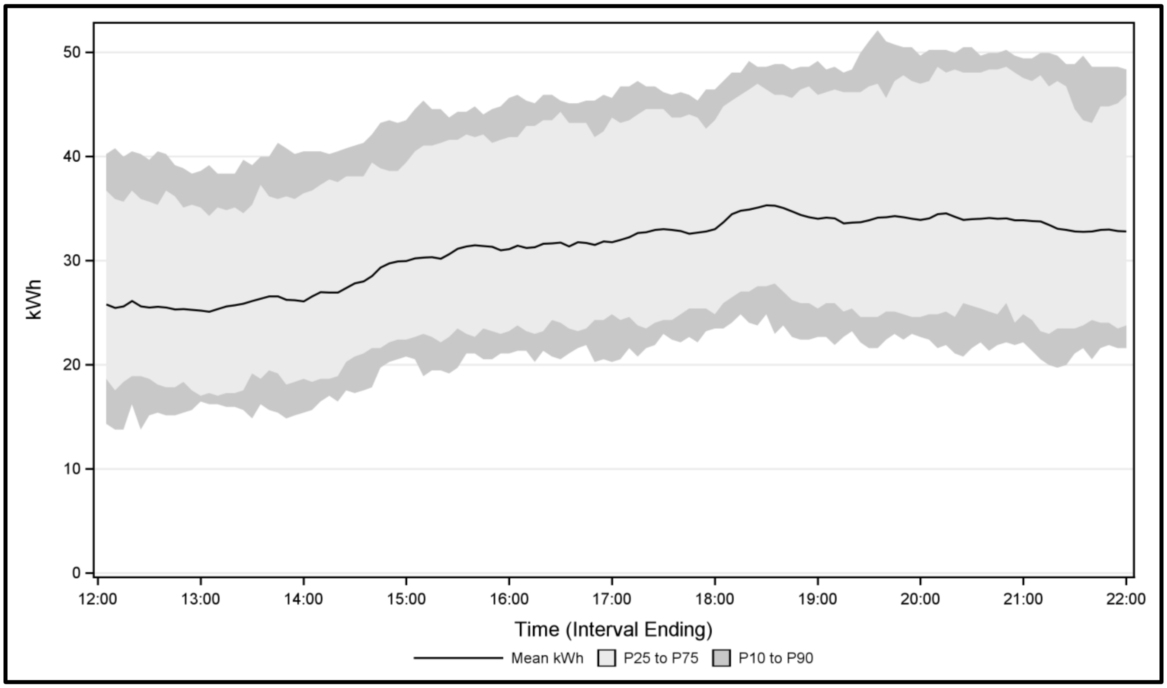


Figure 3-26 depicts a different type of high variability. Instead of a consistent level of variability throughout the day, this participant has a relatively narrow band associated with the interquartile range, but for certain periods during the day there are very large declines in the load as shown by the 10th percentile. The participant's insensitivity to temperature is visible in the lack of any upward trend in average load for the afternoon hours.

Figure 3-26: Load Profile for Participant with High Variability and Low Temperature Sensitivity

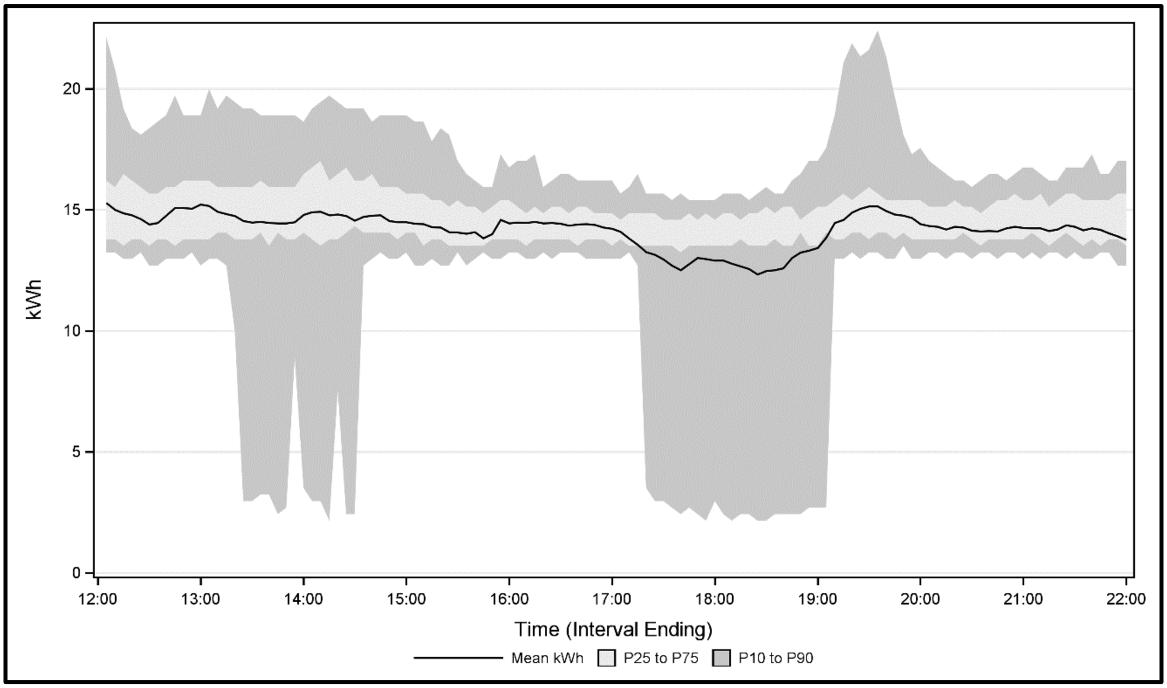


Figure 3-27 and Figure 3-28 are both load profiles for participants with low variability, but with high and low temperature sensitivity, respectively. In both figures, the narrow percentile bands show the lack of variability, but in Figure 3-27 the load's relationship to temperature is subtle but visible in the rise in average load before the evening hours. In contrast, Figure 3-28 has a generally flat average load with no clear association with hotter afternoon temperatures.

Figure 3-27: Load Profile for Participant with Low Variability and High Temperature sensitivity

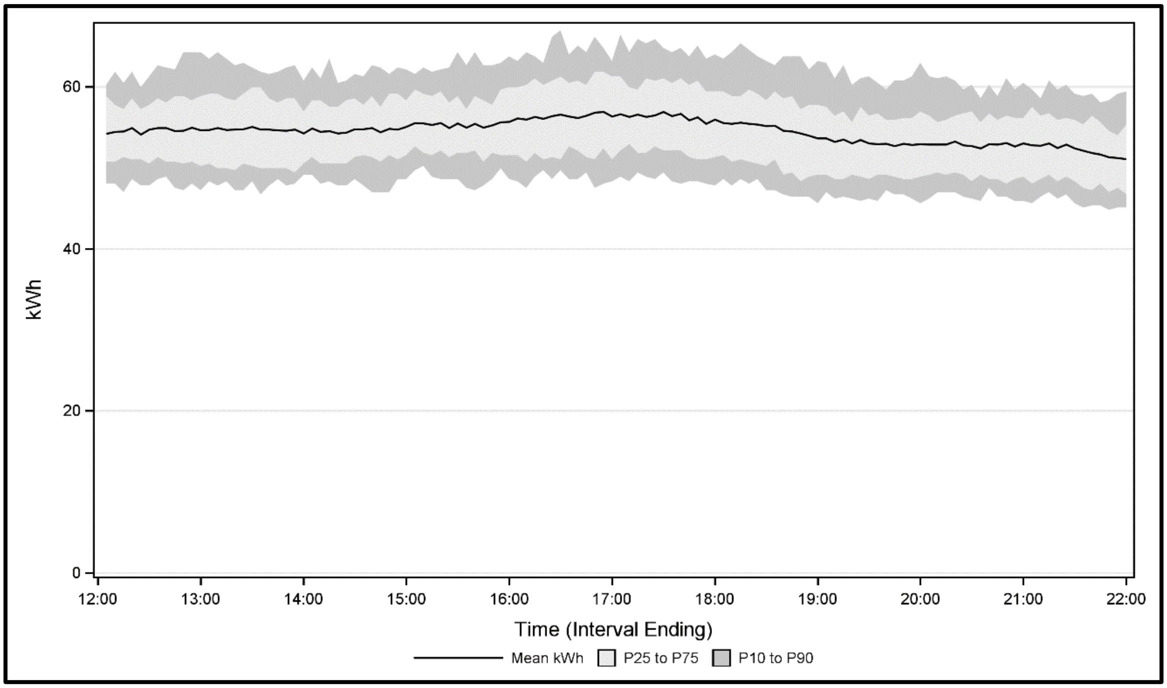
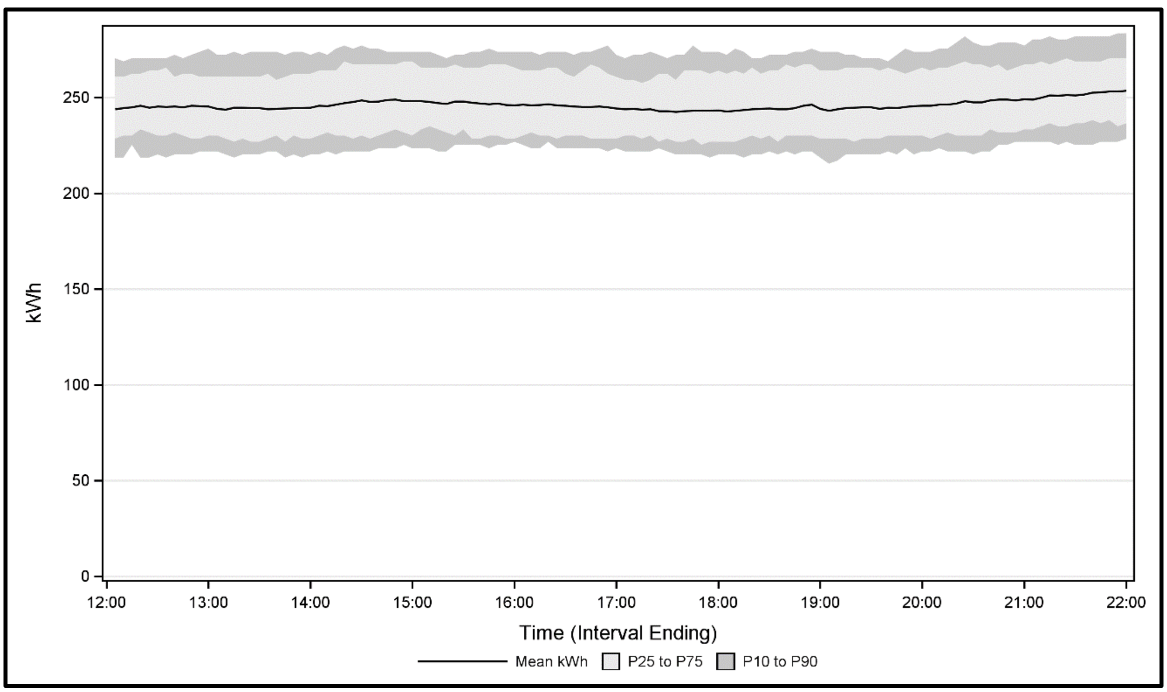


Figure 3-28: Load Profile for Participant with Low Variability and Low Temperature sensitivity



3.2.2 Regression Baseline & Proxy Event Baseline Analyses

The comparison of different baseline approaches (regression versus settlement, different adjustment approaches) using actual events has limited value. Without some sense of whether one approach is "better" compared to the others, it is difficult to ascribe much meaning to the results. As a means of assessing the different approaches, a proxy event analysis was conducted for five days using the data from Season 5 (summer 2015). In addition to having the most participants and most completed data, Season 5 also included many non-event hot days, which is essential to replicate event-like conditions.

The selection of the proxy event days was based on the five hottest non-event weekdays in terms of daily maximum temperature. Table 3-7 shows a comparison of average and maximum temperatures proxy event days with the four actual event days for summer of 2015. In terms of average daily temperatures, the actual events were slightly warmer than the proxy event days, but the two sets were the same in terms of the average of the maximum daily temperatures. Overall, the proxy event days are likely representative of weather conditions on typical event days.

Table 3-7: Temperature Summary for Actual and Proxy Event Days in Season 5

Day Type	Date	Average Daily Temperature °F	Maximum Daily Temperature °F	Average of Average Daily Temperature °F	Average of Maximum Daily Temperature °F
Actual Event	7/1/2015	78.0	95.0	80.0	96.3
	7/2/2015	81.2	97.0		
	7/30/2015	83.0	102.2		
	8/12/2015	77.9	91.0		
Proxy Event	7/29/2015	79.2	96.1	78.3	96.3
	7/31/2015	82.5	100.4		
	8/18/2015	77.4	95.0		
	8/19/2015	77.9	96.1		
	9/11/2015	74.7	93.9		

Baselines were estimated for these proxy event days using the settlement baseline approach and the regression model described previously. The method for the settlement baseline's additive adjustment was applied to both baselines approaches. Additionally, a multiplicative adjustment was calculated as an alternative. Because these events are hypothetical, an adjustment window starting at 12:00 p.m. was assumed, as this was consistent with the actual events in 2015. Unadjusted versions of both baseline approaches were retained to see how well the approaches worked without either additive or multiplicative adjustments.

Assessment of the baselines was based on calculating the percent error ([actual kW - baseline kW] / actual kW) and its absolute value in each interval during the availability window for each proxy event and participant–the percent error being a measure of bias and the absolute percent error being a measure of accuracy. These were then summarized by event and participant to get the mean percent error and mean absolute percent error across all intervals to serve as metrics for how well the baselines performed for each participant and event. The use of both percent error and absolute percent error as fit metrics has value for evaluating the baselines. While the mean percent error will be zero if the differences between the actual load and the baseline balance each other out, a non-zero value will indicate if the baseline is biased high (negative) or low (positive). The absolute percent error provides a better measure of overall accuracy, as the errors do not cancel each other out. The summarization of these metrics across all participants includes both mean and median statistics, as comparing the two helps provide a sense of whether there are substantial outliers.

Table 3-8 provides a summary of the different baseline metrics by baseline type, adjustment method, and event date. For the unadjusted baselines, the regression has overall better performance for both the percent error and absolute percent error. For example, the average and median (middle value) percent error are -4.9% and -1.0% for the regression baseline, which indicates an upward bias due in part to some large outliers. In contrast, the settlement baseline has an average percent error of -11.2%, showing a substantially larger bias upwards. This is due to much larger outliers, however, as the median value is 1.7%. With respect to the absolute percent error, the regression baselines perform better overall for both the average (19.1% for regression versus 23.7% for the settlement baseline) and median values (8.1% for regression versus 9% for the settlement baseline). While this is mostly true for the individual events, the variability across event dates suggests that these are still volatile metrics. With adjustments applied, the differences between the regression and settlement baselines become smaller and the overall best average fit depends on the metric, statistic, and level of summary in question.

Table 3-8: Summary of Metrics by Baseline Method and Proxy Event Day

Adjustment and Even Date		Percent Error (Bias)				Absolute Percent Error (Accuracy)			
		Regression		Settlement		Regression		Settlement	
		Mean	Median	Mean	Median	Mean	Median	Mean	Median
None	7/29/2015	1.1%	-3.0%	0.9%	3.4%	12.4%	8.1%	12.8%	9.7%
	7/31/2015	-0.9%	-1.0%	-8.7%	3.5%	18.9%	9.0%	24.3%	10.8%
	8/18/2015	-2.9%	-0.6%	-14.2%	1.0%	16.2%	6.6%	24.5%	7.5%
	8/19/2015	-1.0%	-0.7%	-7.9%	0.7%	14.4%	7.8%	17.5%	8.7%
	9/11/2015	-21.0%	-0.9%	-26.2%	1.3%	34.1%	8.4%	39.2%	9.2%
	All	-4.9%	-1.0%	-11.2%	1.7%	19.2%	8.1%	23.7%	9.0%
Additive	7/29/2015	-7.6%	-2.6%	-2.0%	0.5%	19.4%	8.5%	15.2%	8.9%
	7/31/2015	-10.5%	0.1%	-6.7%	-1.3%	24.1%	11.5%	19.1%	8.2%
	8/18/2015	-6.8%	0.7%	-10.5%	1.3%	16.9%	6.5%	21.0%	8.0%
	8/19/2015	-2.0%	-0.4%	-6.2%	-1.2%	13.5%	6.6%	15.7%	5.9%
	9/11/2015	-1.3%	1.7%	-6.2%	-0.7%	19.3%	7.4%	20.2%	7.8%
	All	-5.6%	-0.3%	-6.3%	-0.1%	18.6%	8.0%	18.2%	7.7%
Multiplicative	7/29/2015	-4.1%	-2.4%	-1.1%	0.1%	16.6%	9.4%	14.5%	8.9%
	7/31/2015	-7.1%	0.5%	-8.1%	-1.9%	21.2%	11.6%	19.7%	8.7%
	8/18/2015	-6.8%	0.9%	-13.2%	1.2%	16.5%	7.1%	23.4%	8.4%
	8/19/2015	-0.9%	-0.4%	-7.1%	-1.6%	12.8%	6.6%	16.3%	6.5%
	9/11/2015	-2.6%	1.4%	-9.1%	-0.4%	18.9%	7.7%	21.3%	8.0%
	All	-4.3%	-0.0%	-7.7%	-0.2%	17.2%	8.0%	19.0%	7.9%

The baseline fit metrics allow for a validation of the variability and temperature sensitivity characterizations developed. One of the justifications for exploring the characterizations of participants was to see if there are participants for whom the settlement baseline type is poorly suited. Table 3-9 and Table 3-10 show summaries of the two fit metrics across all events for the variability and temperature sensitivity groups for the unadjusted and additive adjustment baselines, respectively. Results for the multiplicative adjustment have been omitted because the additive adjustment, which is the official approach for the settlement baseline, had highly similar results.

Overall, the summaries corroborate the idea that the highly variable participants will present difficulties for the settlement baseline. For example, the mean absolute percent error for the unadjusted settlement baseline for all of the high variability participants is 53.1% compared to 12.7% for the medium group and 5.9% for the low. The additive adjustment mitigates the inaccuracy of the baselines, but the high variability participants still have considerably worse settlement baselines (39.2% mean absolute percent error compared to 10.4% and 5.6% for medium and low, respectively).

Table 3-9: Summary of Metrics by Baseline Method for Unadjusted Baselines by Variability and Temperature Sensitivity Groups

Variability Group	Temperature Sensitivity Group	Percent Error (Bias)				Absolute Percent Error (Accuracy)			
		Regression		Settlement		Regression		Settlement	
		Mean	Median	Mean	Median	Mean	Median	Mean	Median
High	Medium	-11.9%	-8.2%	-8.7%	-6.0%	26.2%	21.8%	23.8%	18.0%
	Low	-11.7%	2.2%	-54.2%	-7.8%	47.8%	28.1%	72.7%	28.0%
	All	-11.8%	-3.4%	-36.0%	-6.4%	39.2%	23.4%	53.1%	21.5%
Medium	High	-3.0%	-3.2%	7.6%	8.0%	6.0%	5.6%	9.0%	8.7%
	Medium	-9.7%	4.1%	-8.5%	0.9%	21.7%	7.9%	18.0%	7.7%
	Low	8.4%	7.8%	-4.6%	-4.0%	16.0%	10.7%	13.9%	9.0%
	All	-3.0%	-0.6%	0.3%	5.4%	12.8%	7.0%	12.7%	8.7%
Low	High	-1.7%	-1.5%	3.8%	3.7%	4.2%	4.0%	4.5%	4.2%
	Medium	-1.7%	-1.0%	-1.8%	0.2%	7.8%	6.6%	8.1%	6.4%
	Low	6.0%	6.5%	0.3%	2.5%	7.6%	6.9%	5.6%	3.2%
	All	-0.2%	-0.9%	1.2%	2.5%	6.1%	4.7%	5.9%	4.4%
All	High	-2.4%	-2.3%	5.8%	5.1%	5.2%	4.5%	6.9%	5.9%
	Medium	-8.0%	-1.4%	-6.5%	0.1%	19.1%	10.0%	17.1%	9.5%
	Low	-4.1%	7.1%	-33.4%	-3.5%	33.4%	20.1%	47.5%	18.8%
	All	-4.9%	-1.0%	-11.2%	1.7%	19.2%	8.1%	23.7%	9.0%

Table 3-10: Summary of Metrics by Baseline Method for Additive Adjustment Baselines by Variability and Temperature Sensitivity Groups

Variability Group	Temperature Sensitivity Group	Interval Percent Error (Bias)				Interval Absolute Percent Error (Accuracy)			
		Regression		Settlement		Regression		Settlement	
		Mean	Median	Mean	Median	Mean	Median	Mean	Median
High	**Medium**	-15.5%	-8.2%	-23.1%	-11.4%	28.0%	20.8%	29.3%	15.4%
	Low	-12.9%	-4.4%	-13.3%	-7.0%	47.8%	29.1%	45.9%	32.2%
	All	-14.0%	-6.6%	-17.2%	-9.1%	39.9%	25.9%	39.2%	24.3%
Medium	**High**	1.5%	1.5%	3.9%	4.6%	5.6%	4.8%	6.9%	6.9%
	Medium	-8.2%	0.5%	-7.2%	0.5%	16.5%	7.0%	15.4%	7.2%
	Low	-3.5%	-3.8%	-3.8%	-2.9%	13.9%	11.6%	11.4%	8.0%
	All	-2.5%	0.8%	-1.0%	1.6%	10.6%	6.2%	10.4%	7.3%
Low	**High**	1.1%	0.9%	0.3%	0.7%	3.6%	3.4%	3.4%	3.2%
	Medium	-2.6%	-1.5%	-2.5%	-1.3%	10.1%	5.5%	9.5%	6.1%
	Low	-1.7%	-1.3%	-2.1%	-0.1%	5.0%	4.2%	4.2%	3.1%
	All	-0.7%	0.3%	-1.1%	0.0%	6.0%	3.8%	5.6%	3.6%
All	**High**	1.3%	1.1%	2.2%	1.5%	4.6%	4.0%	5.3%	4.4%
	Medium	-9.2%	-2.3%	-11.7%	-1.0%	18.8%	10.9%	18.8%	8.0%
	Low	-8.8%	-2.7%	-9.1%	-3.0%	32.5%	20.1%	30.6%	19.2%
	All	-5.6%	-0.3%	-6.3%	-0.1%	18.6%	8.0%	18.2%	7.7%

The results in Table 3-9 and Table 3-10 also validate the temperature sensitivity classifications. The participants with high temperature sensitivity have much better baseline performance for both settlement and regression baselines. These results for temperature sensitivity are easily observed in the lower right of both tables, but in general these summaries clearly validate the general supposition that high variability and low temperature sensitivity present complications for both types of baselines. Furthermore, these results show that the adjustment generally improves the fit, but not nearly to the point that the accuracy is comparable to the low variability and/or high temperature sensitivity participants.

In the results presented thus far, there is a log of underlying variability that obscures that for each participant and event one of the baselines is "better" in terms of the fit metrics. The 46 participants and five proxy events amount to a total of 230 comparisons where one baseline can be selected as "better" than the other. As another means of summarizing which baseline methods are best, Table 3-11 presents the counts of how often the regression or settlement baselines were deemed better based on the different metric and statistic for the unadjusted baselines and the two adjustment types.

Table 3-11: Overall Frequency of Best Baseline by Adjustment, Metric, and Statistic

Metric/Stat/Model		None			Additive			Multiplicative		
		# Selected Best	# Selected Best	Mean Fit Metric	# Selected Best	# Selected Best	Mean Fit Metric	# Selected Best	# Selected Best	Mean Fit Metric
Percent Error (Bias)	Regression	133	57.8%	-8.3%	116	50.4%	-1.9%	112	48.7%	-1.4%
	Settlement	97	42.2%	-2.2%	114	49.6%	-5.0%	118	51.3%	-4.4%
Absolute Percent Error (Accuracy)	Regression	115	50.0%	19.6%	107	46.5%	13.8%	106	46.1%	12.7%
	Settlement	115	50.0%	12.7%	123	53.5%	15.4%	124	53.9%	14.8%

Note: "Baseline Adjustment" spans the None, Additive and Multiplicative column groups.

For the unadjusted baselines, based on the average percent error, the regression baseline was selected as best nearly 58% of the time. However, the use of the percent error is primarily to see if there is bias, which is not always the primary concern in assessing baseline performance. In terms of the overall accuracy, the unadjusted baselines were each selected exactly half the time for both methods. When adjustments are applied, the settlement baseline was selected more often than the regression model, though not by a very large margin.

Overall, there is not any overwhelming evidence to suggest the use of one baseline over another or even necessarily any particular adjustment. Given this ambiguity, the next question is whether there is any evidence that any one method was consistently selected as the best for an individual participant. Alternately, the question is whether any participants had the same baseline—either regression or settlement–selected as best for all five of the proxy events. To address this issue, Table 3-12, Table 3-13, and Table 3-14 show by variability and temperature sensitivity groups the frequency of participants based on the number of times they selected a particular baseline method as best for the unadjusted, additive adjustment, and multiplicative adjustment baselines, respectively. The summaries have the additional benefit of providing the overall numbers presented in Table 3-12 by the temperature sensitivity and variability groups.

Table 3-12: Frequency Selected "Best" per Participant by Unadjusted Baseline Type Using Absolute Percent Error

Variability Group/Temperature sensitivity Group/# Times Selected Best			Baseline Type: Regression # Selected	Regression % Selected Overall	Regression % Selected by Model	Regression Average of Fit Metric	Settlement # Selected	Settlement % Selected Overall	Settlement % Selected by Model	Settlement Average of Fit Metric
High	**All**	**1**	3	10.3%	21.4%	17.8%	4	13.8%	26.7%	20.6%
		2	3	10.3%	21.4%	33.1%	4	13.8%	26.7%	27.3%
		3	4	13.8%	28.6%	44.4%	3	10.3%	20.0%	26.5%
		4	4	13.8%	28.6%	62.2%	3	10.3%	20.0%	18.1%
		5	0	0.0%	0.0%	0.0%	1	3.4%	6.7%	9.7%
		All Events	37	49.3%	100.0%	41.4%	38	50.7%	100.0%	22.4%
Medium	**All**	**1**	0	0.0%	0.0%	0.0%	5	17.2%	35.7%	5.8%
		2	6	20.7%	40.0%	10.3%	2	6.9%	14.3%	9.8%
		3	2	6.9%	13.3%	6.8%	6	20.7%	42.9%	6.9%
		4	5	17.2%	33.3%	6.5%	0	0.0%	0.0%	0.0%
		5	2	6.9%	13.3%	3.6%	1	3.4%	7.1%	49.6%
		All Events	48	60.0%	100.0%	7.7%	32	40.0%	100.0%	10.0%
Low	**All**	**1**	5	17.9%	38.5%	4.1%	3	10.7%	20.0%	4.4%
		2	2	7.1%	15.4%	3.7%	3	10.7%	20.0%	12.1%
		3	3	10.7%	23.1%	7.3%	2	7.1%	13.3%	3.1%
		4	3	10.7%	23.1%	3.7%	5	17.9%	33.3%	4.5%
		5	0	0.0%	0.0%	0.0%	2	7.1%	13.3%	1.6%
		All Events	30	40.0%	100.0%	4.7%	45	60.0%	100.0%	5.4%
All	**High**	**1**	1	3.7%	7.1%	5.5%	7	25.9%	53.8%	5.4%
		2	3	11.1%	21.4%	4.1%	1	3.7%	7.7%	5.5%
		3	1	3.7%	7.1%	4.8%	3	11.1%	23.1%	3.8%
		4	7	25.9%	50.0%	5.1%	1	3.7%	7.7%	3.2%
		5	2	7.4%	14.3%	3.6%	1	3.7%	7.7%	1.8%
		All Events	48	64.0%	100.0%	4.7%	27	36.0%	100.0%	4.6%
	Medium	**1**	2	6.9%	15.4%	7.2%	2	6.9%	12.5%	7.6%
		2	5	17.2%	38.5%	18.8%	4	13.8%	25.0%	15.5%
		3	4	13.8%	30.8%	17.9%	5	17.2%	31.3%	12.0%
		4	2	6.9%	15.4%	10.3%	2	6.9%	12.5%	9.4%
		5	0	0.0%	0.0%	0.0%	3	10.3%	18.8%	20.2%
		All Events	32	40.0%	100.0%	15.4%	48	60.0%	100.0%	13.5%
	Low	**1**	5	16.7%	33.3%	10.8%	3	10.0%	20.0%	24.0%
		2	3	10.0%	20.0%	20.9%	4	13.3%	26.7%	24.4%
		3	4	13.3%	26.7%	34.2%	3	10.0%	20.0%	18.7%
		4	3	10.0%	20.0%	78.7%	5	16.7%	33.3%	11.0%
		5	0	0.0%	0.0%	0.0%	0	0.0%	0.0%	0.0%
		All Events	35	46.7%	100.0%	32.6%	40	53.3%	100.0%	18.7%
	All	**1**	8	9.3%	19.0%	9.2%	12	14.0%	27.3%	10.4%
		2	11	12.8%	26.2%	15.3%	9	10.5%	20.5%	18.3%
		3	9	10.5%	21.4%	23.7%	11	12.8%	25.0%	11.6%
		4	12	14.0%	28.6%	24.4%	8	9.3%	18.2%	9.6%
		5	2	2.3%	4.8%	3.6%	4	4.7%	9.1%	15.6%
		All Events	115	50.0%	100.0%	18.0%	115	50.0%	100.0%	12.7%

Table 3-13: Frequency Selected "Best" per Participant by Additive Adjustment Baseline Type Using Median Absolute Percent Error

Variability Group/Temperature sensitivity Group/# Times Selected Best			Baseline Type: Regression # Selected	Regression % Selected Overall	Regression % Selected by Model	Regression Average of Fit Metric	Settlement # Selected	Settlement % Selected Overall	Settlement % Selected by Model	Settlement Average of Fit Metric
High	**All**	**1**	5	17.2%	35.7%	19.6%	3	10.3%	20.0%	28.2%
		2	3	10.3%	21.4%	38.2%	3	10.3%	20.0%	45.2%
		3	3	10.3%	21.4%	36.4%	3	10.3%	20.0%	45.5%
		4	3	10.3%	21.4%	32.1%	5	17.2%	33.3%	22.5%
		5	0	0.0%	0.0%	0.0%	1	3.4%	6.7%	8.4%
		All Events	32	42.7%	100.0%	29.9%	43	57.3%	100.0%	31.9%
Medium	**All**	**1**	1	3.4%	7.1%	13.4%	3	10.3%	20.0%	4.9%
		2	3	10.3%	21.4%	4.4%	6	20.7%	40.0%	7.5%
		3	6	20.7%	42.9%	6.6%	3	10.3%	20.0%	4.7%
		4	3	10.3%	21.4%	4.7%	1	3.4%	6.7%	12.2%
		5	1	3.4%	7.1%	3.9%	2	6.9%	13.3%	27.5%
		All Events	42	52.5%	100.0%	6.1%	38	47.5%	100.0%	9.4%
Low	**All**	**1**	5	16.7%	33.3%	4.3%	2	6.7%	13.3%	3.5%
		2	4	13.3%	26.7%	3.4%	4	13.3%	26.7%	6.4%
		3	4	13.3%	26.7%	6.2%	4	13.3%	26.7%	4.1%
		4	2	6.7%	13.3%	9.7%	5	16.7%	33.3%	2.6%
		5	0	0.0%	0.0%	0.0%	0	0.0%	0.0%	0.0%
		All Events	33	44.0%	100.0%	5.3%	42	56.0%	100.0%	4.1%
All	**High**	**1**	3	10.3%	20.0%	2.6%	3	10.3%	21.4%	4.9%
		2	4	13.8%	26.7%	3.1%	4	13.8%	28.6%	3.9%
		3	4	13.8%	26.7%	5.2%	4	13.8%	28.6%	3.9%
		4	3	10.3%	20.0%	4.7%	3	10.3%	21.4%	2.4%
		5	1	3.4%	6.7%	3.9%	0	0.0%	0.0%	0.0%
		All Events	40	53.3%	100.0%	3.9%	35	46.7%	100.0%	3.8%
	Medium	**1**	5	16.7%	35.7%	16.8%	2	6.7%	12.5%	11.0%
		2	3	10.0%	21.4%	4.8%	4	13.3%	25.0%	12.5%
		3	4	13.3%	28.6%	10.3%	3	10.0%	18.8%	4.9%
		4	2	6.7%	14.3%	34.0%	5	16.7%	31.3%	17.4%
		5	0	0.0%	0.0%	0.0%	2	6.7%	12.5%	25.9%
		All Events	31	38.8%	100.0%	14.8%	49	61.3%	100.0%	14.1%
	Low	**1**	3	10.3%	21.4%	13.9%	3	10.3%	20.0%	23.2%
		2	3	10.3%	21.4%	38.2%	5	17.2%	33.3%	28.1%
		3	5	17.2%	35.7%	22.4%	3	10.3%	20.0%	45.5%
		4	3	10.3%	21.4%	15.9%	3	10.3%	20.0%	14.6%
		5	0	0.0%	0.0%	0.0%	1	3.4%	6.7%	11.7%
		All Events	36	48.0%	100.0%	22.6%	39	52.0%	100.0%	26.8%
	All	**1**	11	12.5%	25.6%	12.1%	8	9.1%	17.8%	13.3%
		2	10	11.4%	23.3%	14.1%	13	14.8%	28.9%	15.9%
		3	13	14.8%	30.2%	13.4%	10	11.4%	22.2%	16.7%
		4	8	9.1%	18.6%	16.2%	11	12.5%	24.4%	12.5%
		5	1	1.1%	2.3%	3.9%	3	3.4%	6.7%	21.2%
		All Events	107	46.5%	100.0%	13.5%	123	53.5%	100.0%	15.1%

Table 3-14: Frequency Selected "Best" per Participant by Multiplicative Adjustment Baseline Type Using Median Absolute Percent Error

Variability Group/Temperature sensitivity Group/# Times Selected Best			Baseline Type: Regression				Baseline Type: Settlement			
			# Selected	% Selected Overall	% Selected by Model	Average of Fit Metric	# Selected	% Selected Overall	% Selected by Model	Average of Fit Metric
High	**All**	**1**	6	20.0%	40.0%	30.4%	3	10.0%	20.0%	24.1%
		2	4	13.3%	26.7%	24.4%	2	6.7%	13.3%	47.0%
		3	2	6.7%	13.3%	18.7%	4	13.3%	26.7%	27.3%
		4	3	10.0%	20.0%	32.3%	6	20.0%	40.0%	25.5%
		5	0	0.0%	0.0%	0.0%	0	0.0%	0.0%	0.0%
		All Events	32	42.7%	100.0%	27.6%	43	57.3%	100.0%	28.5%
Medium	**All**	**1**	0	0.0%	0.0%	0.0%	2	6.7%	12.5%	7.1%
		2	3	10.0%	21.4%	6.7%	9	30.0%	56.3%	7.0%
		3	9	30.0%	64.3%	6.7%	3	10.0%	18.8%	6.2%
		4	2	6.7%	14.3%	5.0%	0	0.0%	0.0%	0.0%
		5	0	0.0%	0.0%	0.0%	2	6.7%	12.5%	27.7%
		All Events	41	51.3%	100.0%	6.5%	39	48.8%	100.0%	9.5%
Low	**All**	**1**	6	20.0%	40.0%	3.9%	2	6.7%	13.3%	3.6%
		2	2	6.7%	13.3%	3.6%	5	16.7%	33.3%	5.8%
		3	5	16.7%	33.3%	6.0%	2	6.7%	13.3%	4.8%
		4	2	6.7%	13.3%	9.7%	6	20.0%	40.0%	2.7%
		5	0	0.0%	0.0%	0.0%	0	0.0%	0.0%	0.0%
		All Events	33	44.0%	100.0%	5.3%	42	56.0%	100.0%	4.1%
All	**High**	**1**	4	13.3%	26.7%	2.4%	2	6.7%	13.3%	7.1%
		2	3	10.0%	20.0%	3.3%	6	20.0%	40.0%	4.6%
		3	6	20.0%	40.0%	5.4%	3	10.0%	20.0%	3.8%
		4	2	6.7%	13.3%	5.0%	4	13.3%	26.7%	2.6%
		5	0	0.0%	0.0%	0.0%	0	0.0%	0.0%	0.0%
		All Events	36	48.0%	100.0%	4.1%	39	52.0%	100.0%	4.2%
	Medium	**1**	4	12.9%	26.7%	18.7%	2	6.5%	12.5%	12.4%
		2	3	9.7%	20.0%	9.0%	6	19.4%	37.5%	9.9%
		3	6	19.4%	40.0%	8.8%	3	9.7%	18.8%	9.6%
		4	2	6.5%	13.3%	35.4%	4	12.9%	25.0%	17.9%
		5	0	0.0%	0.0%	0.0%	1	3.2%	6.3%	43.5%
		All Events	36	45.0%	100.0%	15.0%	44	55.0%	100.0%	14.3%
	Low	**1**	4	13.8%	28.6%	30.4%	3	10.3%	20.0%	18.2%
		2	3	10.3%	21.4%	29.4%	4	13.8%	26.7%	24.9%
		3	4	13.8%	28.6%	10.7%	3	10.3%	20.0%	32.4%
		4	3	10.3%	21.4%	15.2%	4	13.8%	26.7%	21.8%
		5	0	0.0%	0.0%	0.0%	1	3.4%	6.7%	11.9%
		All Events	34	45.3%	100.0%	21.3%	41	54.7%	100.0%	23.4%
	All	**1**	12	13.3%	27.3%	17.2%	7	7.8%	15.2%	13.4%
		2	9	10.0%	20.5%	13.9%	16	17.8%	34.8%	11.7%
		3	16	17.8%	36.4%	8.0%	9	10.0%	19.6%	15.3%
		4	7	7.8%	15.9%	18.1%	12	13.3%	26.1%	14.1%
		5	0	0.0%	0.0%	0.0%	2	2.2%	4.3%	27.7%
		All Events	106	46.1%	100.0%	13.3%	124	53.9%	100.0%	13.9%

There is a substantial amount of data in these tables, but the discussion will be limited to the main takeaways. Firstly, there are very few participants who consistently had the same baseline method as best. For the unadjusted baselines, there were only two participants who always had the regression baseline as best and four who always had the settlement baseline as best. After applying adjustments, even fewer cases occurred. For the additive baseline, only one participant always selected regression and three always selected regression. For the multiplicative baseline, only two participants selected the settlement baseline as best for all five proxy events.

If one expands the definition of consistency to baselines selected for four or more events and then looks into the variability and temperature sensitivity groups, there are more meaningful findings. For example, for the high variability group for the additive adjustment (Table 3-13), the settlement baseline was selected as best for 43 of 75 comparisons (57%) and of those, 21 were associated with six participants where this baseline performed better for at least four of the proxy events. In contrast, 35.7% of the cases where regression was the better baseline for this high variability group were based on participants selecting this baseline for just one proxy event. A similar contrast was not evident for the group of high temperature sensitivity participants. Again, looking at the results for the additive adjustment, the overall total number of comparisons leaned slightly towards regression (53.3%), but for both regression and settlement baselines, more than two-thirds of the participants had selected the baseline no more than three times.

Overall, the results suggest that there are few compelling reasons to assume that one baseline method should be selected over the other. There are a few clear cut cases for a handful of participants, but for the majority of participants the best baseline often comes down to idiosyncrasies in the load that are far too complex to model in a way that could be made operational from a program point of view. For situations where one baseline method works well, the other generally also produces a similar baseline. For situations where a baseline method performs poorly, the other method generally also performs poorly.

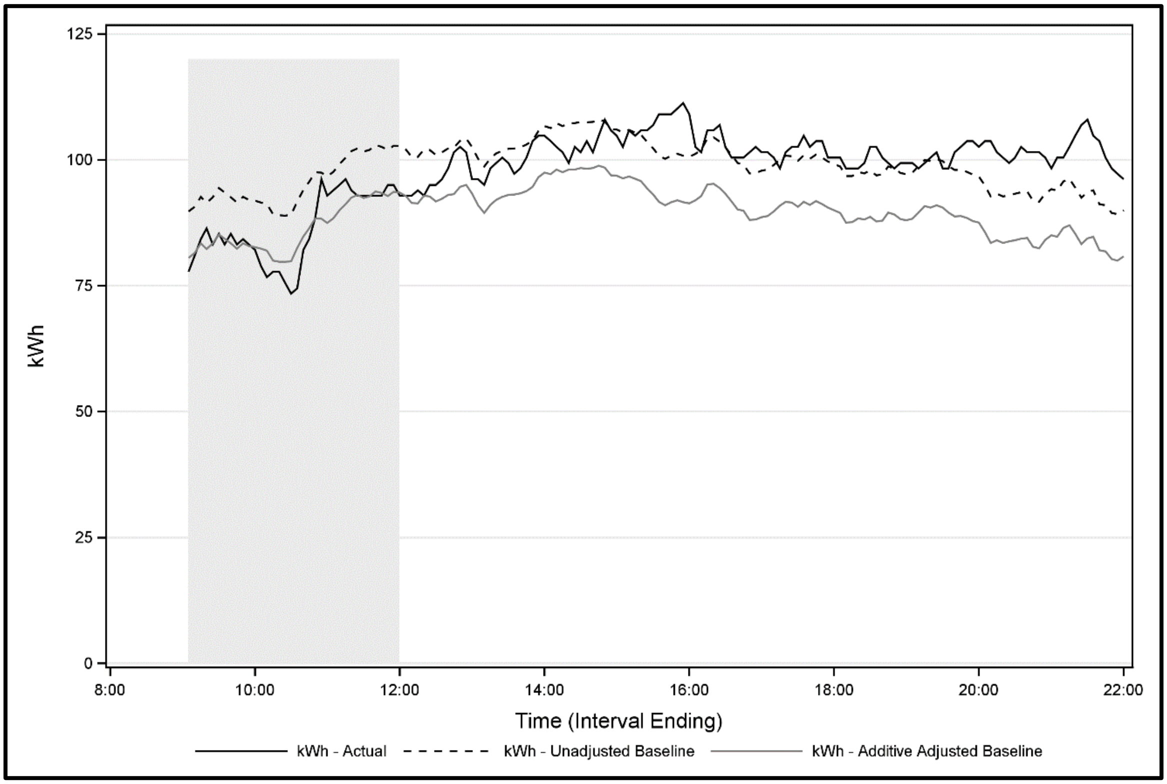
As a final topic using the proxy event baselines, the approach of selecting the “best” baseline by method was applied to the type of adjustment. These results are presented in Table 3-15. While adjustments are generally assumed to improve the performance of a baseline, this proved to be the case for only a slight majority of the cases. For example, using the absolute percent error to select the best performing adjustment, the unadjusted baselines were selected 44.8% and 43.9% of the time for the regression and settlement baseline, respectively. Furthermore, neither type of adjustment stood out as clearly superior to the other. In some cases the additive baseline was selected more than the multiplicative and in others the reverse occurred, but overall the two were roughly equal.

Table 3-15: Overall Frequency of Best Adjustment by Baseline, Metric, and Statistic

Metric/Stat/Model		Regression			Settlement		
		# Selected Best	# Selected Best	Mean Fit Metric	# Selected Best	# Selected Best	Mean Fit Metric
Percent Error	**None**	107	46.5%	-1.5%	104	45.2%	-2.9%
	Additive	65	28.3%	-3.6%	58	25.2%	-11.3%
	Multiplicative	58	25.2%	-0.5%	68	29.6%	1.1%
Absolute Percent Error	**None**	103	44.8%	13.9%	101	43.9%	13.9%
	Additive	67	29.1%	12.5%	62	27.0%	18.1%
	Multiplicative	60	26.1%	14.3%	67	29.1%	11.7%

Given that adjustments are intended to improve baseline performance, it is worth taking the time to illustrate an example of how an adjustment can adversely affect a baseline's accuracy. Figure 3-29 shows the actual load along with both unadjusted and adjusted baselines for a single participant on one of the proxy events. During the adjustment period, which is identified by the gray shaded area, one can clearly see that the unadjusted baseline is higher than the actual load. This results in a negative downward adjustment. However, as the availability window begins the actual load and the unadjusted baseline actually converge, this results in an adjusted baseline that substantially underestimates the load.

Figure 3-29: Example of Adjustment Leading to Less Accurate Baseline – Regression



Comparison of Alternative Baselines on Impacts for Actual Events for Season Five

The regression baselines and the alternative adjustment types were also used to calculate impacts for the actual events in Season 5 (summer 2015). Table 3-16 provides a summary of the total impacts by event date and overall for both settlement and regression baselines. Given that the proxy event analysis showed that unadjusted baselines performed best very often, the impacts based on the unadjusted baselines are presented along with the two types of adjustments.

Table 3-16: Comparison of Total kWh Impacts by Event and Baseline Method and Adjustment

Event Date	Unadjusted Baselines		Additive Adjustment Baselines		Multiplicative Adjustment Baselines	
	Total Settlement kWh	**Total Regression kWh**	**Total Settlement kWh**	**Total Regression kWh**	**Total Settlement kWh**	**Total Regression kWh**
7/1/2015	27,959	23,216	***28,501***	28,508	28,927	28,393
7/2/2015	23,973	22,620	***30,005***	27,045	30,793	26,997
7/30/2015	20,618	22,593	***24,620***	27,289	26,540	27,970
8/12/2015	25,119	17,176	***22,211***	18,579	22,259	18,246
Total	**97,669**	**85,604**	***105,338***	**101,421**	**108,518**	**101,605**

The settlement baseline with the additive adjustment reflects the impacts as invoiced by EnerNOC and are presented in bold italic text. Overall, only the unadjusted baselines have impacts that differ from the invoiced totals by more than 4%. However, within the individual events there are many cases where the differences associated with the regression baselines are more than 10%. For example, the additive adjustment on the regression baseline on July 30 results in impacts that are more than 10% higher and for August 12 the impacts are more than 10% lower. Overall, the larger differences are seen in comparisons of the baseline type or of the unadjusted baselines with either one of the adjustments. Within the same baseline type, the two adjustment types rarely result in a large difference and never more than 10%.

The differences in total impacts are based on individual impacts for four events for up to 46 different participants. To visualize how these many impact estimates vary, Figure 3-30 provides scatter plots to compare the regression and settlement impacts by adjustment type and event date. While most of the impacts appear to be similar—as indicated by their proximity to the diagonal line—there are clearly many substantial discrepancies. In some cases it is clear that adjustments reduce the number of discrepancies, but there are also instances where larger discrepancies appear after the adjustments have been applied.

Figure 3-30: Scatter Plot of Regression and Settlement Impacts by Adjustment Type

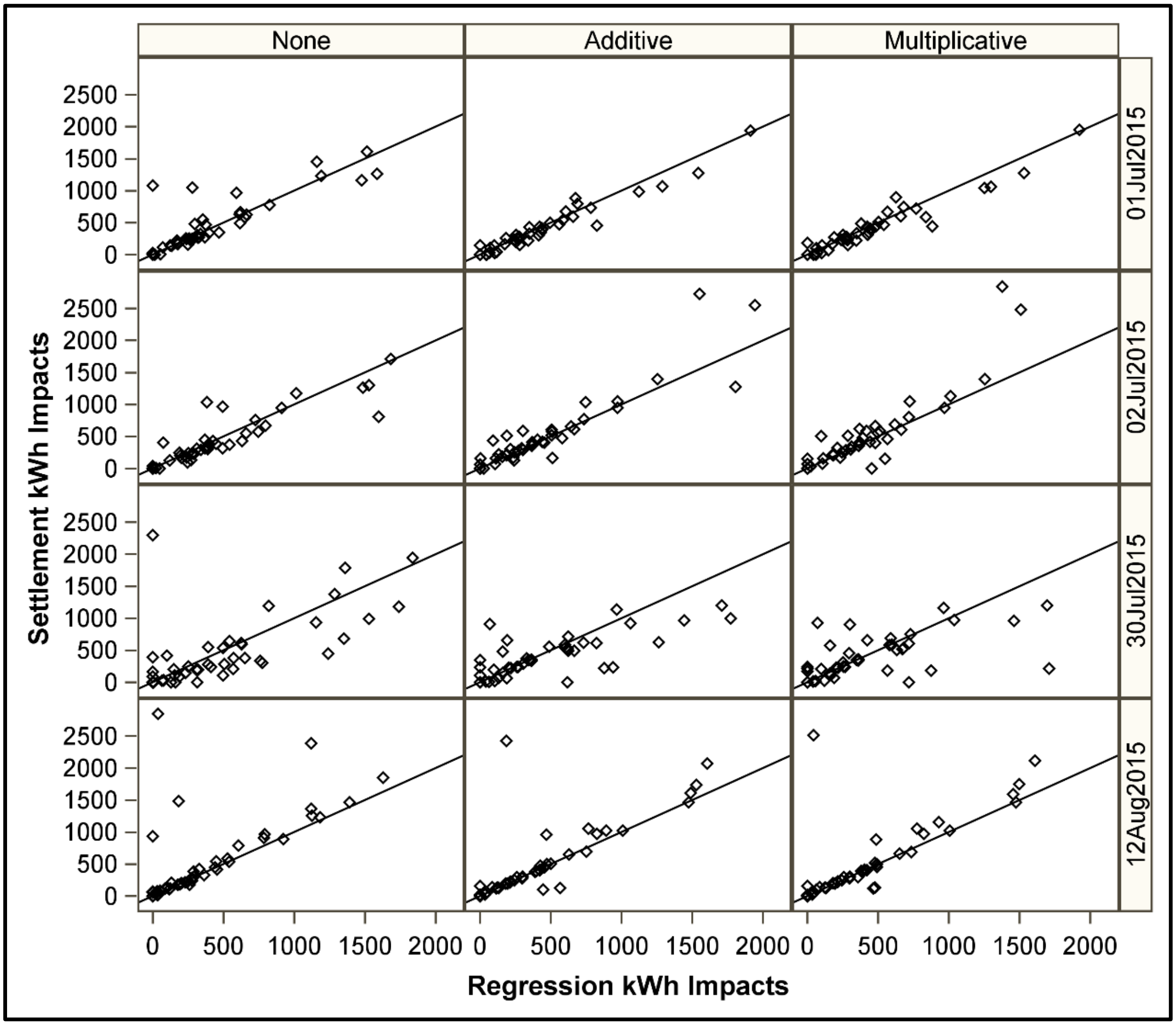
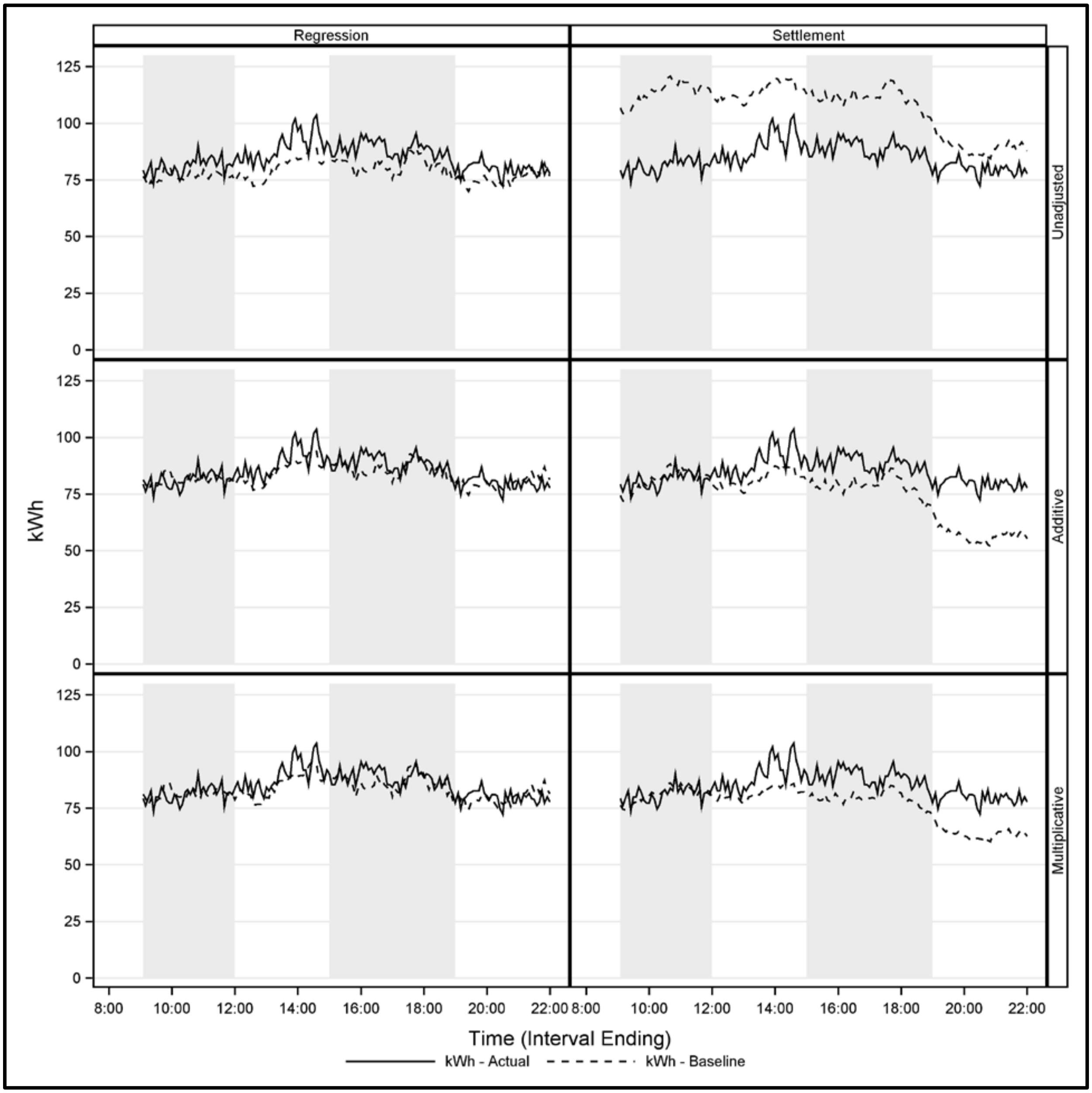
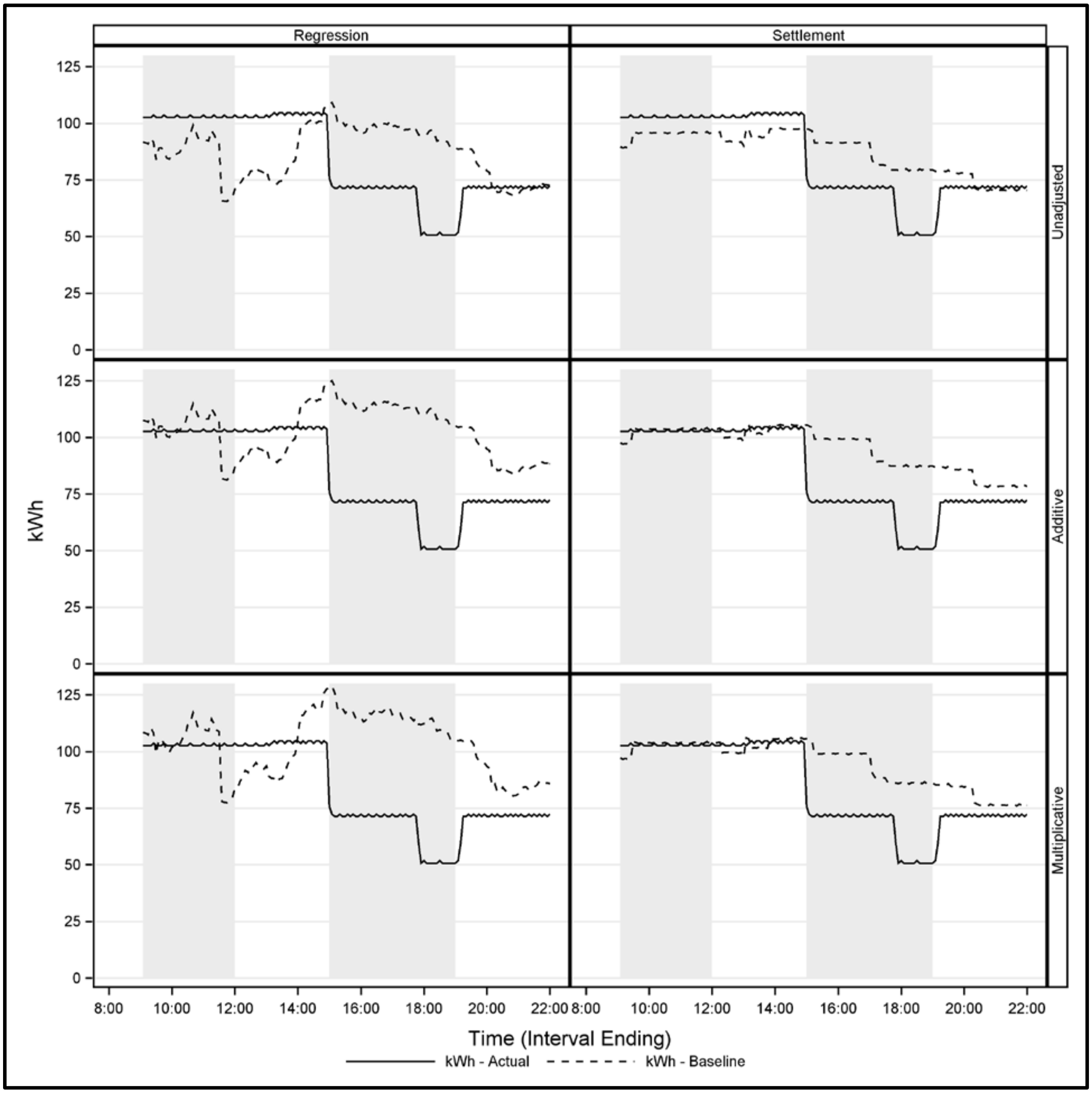


Figure 3-31: Example of Large Initial Discrepancy in kWh Impacts by Baseline Mitigated by Adjustment



The discrepancies are not an indication of one baseline type being wrong. They simply reflect that, for many participants, the baseline methods do not always perform well and that, in many cases, the anomalies in the data can lead to adjustments that actually hamper baseline performance.

Figure 3-32: Example of Adjustment Leading to Larger Discrepancy in kWh Impacts by Baseline



3.2.3 Curtailment Response Speed Analysis

For the final supplemental task, Itron analyzed the response speed of program participants for the Season 5 events. The analysis was based on calculating the degree to which each participant achieves their nominated load shed over each event interval. The five-minute intervals are not sufficient to determine exactly how immediately participants respond to events, but do help to determine if they have fully responded within the 10-minute requirement.

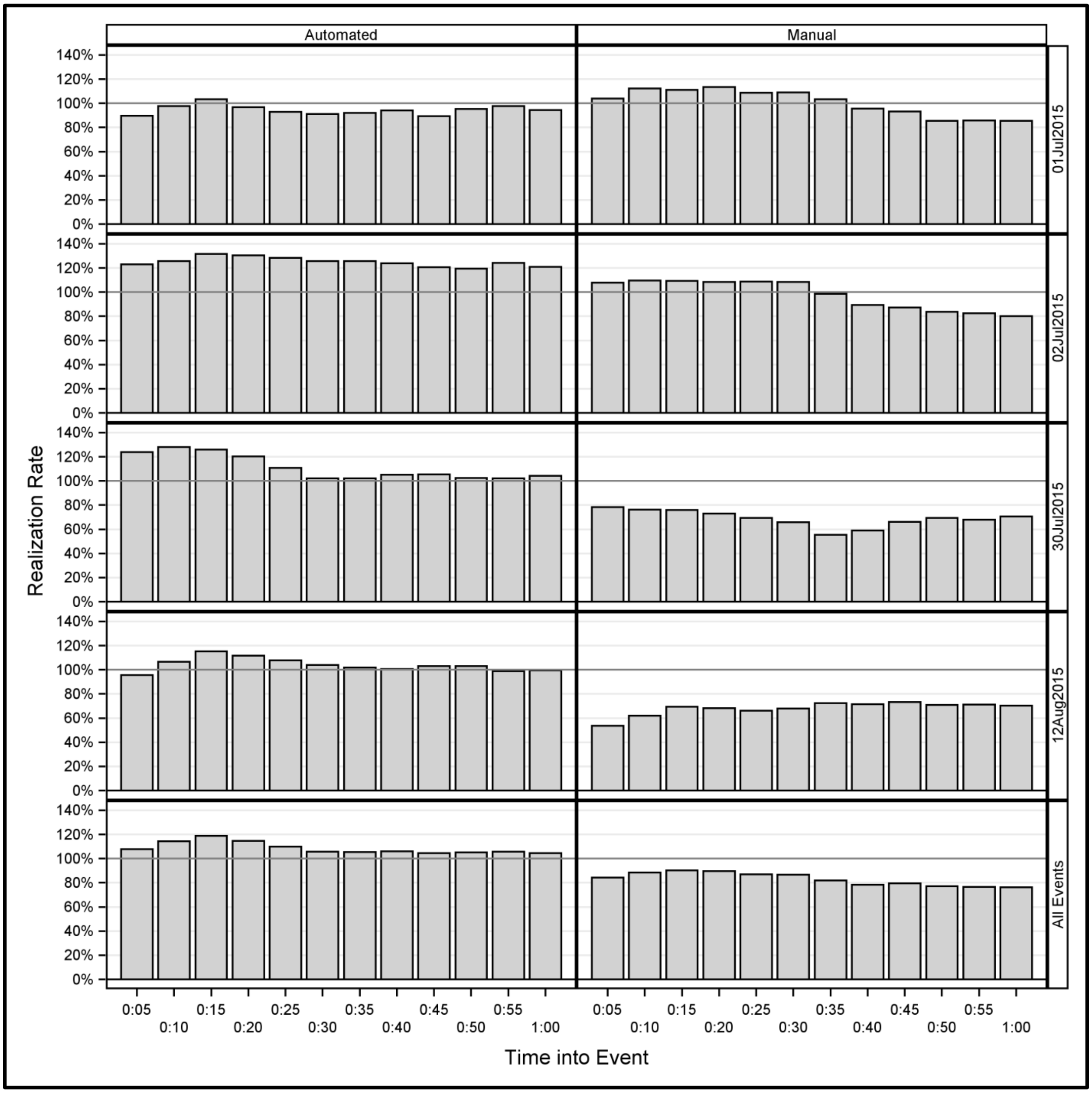
Of particular interest in this analysis is the sites' types of curtailment controls, which for this analysis have been divided into those sites with manual controls and those with automated controls. As shown in Table 3-17, the 46 Season 5 participants are almost evenly divided between the two groups, with 24 participants with manual control and 22 automated. Because the previous analysis has shown that the impacts associated with high variability and/or low temperature sensitivity have more uncertainty, the counts are also shown by the variability and temperature sensitivity groups. It is worth noting that of the 24 manual participants, 12 are in the high variability group and 14 are in the low temperature sensitivity group.

Table 3-17: Count of Participants by Control Type with Variability and Temperature Sensitivity Groups

Variability Group	Temperature Sensitivity Group	Control Type			
		Automated		Manual	
		Participants	Mean 5-Minute kWh	Participants	Mean 5-Minute kWh
High	**Medium**	3	31	3	41
	Low	NA	NA	9	37
	All	3	31	12	38
Medium	**High**	7	30	1	37
	Medium	4	30	1	105
	Low	NA	NA	3	64
	All	11	30	5	67
Low	**High**	6	31	1	54
	Medium	1	22	4	36
	Low	1	145	2	146
	All	8	44	7	70
All	**High**	13	30	2	46
	Medium	8	29	8	47
	Low	1	145	14	58
	All	22	35	24	53

Itron's analysis is primarily visual and it looked at response times in two ways. The first was to consider the participants in the aggregate and compare their collective impacts to the total nominated load curtailment to develop realization rates in each interval. Given that there is uncertainty in the individual impacts, this approach assumes that the errors generally even out and it provides a view of how quickly the overall population of participants respond to events. The results from this approach are shown in Figure 3-33, which shows the realization rates by interval by control type and event date (and across all events). The time series on the x axis represents the time transpired since the start of the event, which allows events with different starting times to be compared and aggregated more easily.

Figure 3-33: Average Aggregation Realization Rate by Event Date



Across all events, the realization rates shown in Figure 3-33 suggest far better response times for the participants with automated controls. They have a realization rate greater than 100% just five minutes into the events, compared to the manual control participants that fall well short of 100% realization rates throughout the first hour. This is an intuitive result given that automated controls would logically be more likely to curtail load in a timely fashion. For the individual event days, however, the picture is not as consistent. For example, for the first two events the manual control participants did achieve a 100% realization rate at the outset of the event, but the subsequent events were markedly lower. Moreover, while the automated participants were more similar across event days, for the July 1 event they did fall slightly short of a 100% realization rate in the events initial minutes.

The aggregate realization rates presented thus far are composed of up to 46 separate event impacts and while the uncertainty around those impacts is an important caveat, there is still value in seeing the variability in individual participant performance. Figure 3-34 shows the average of the participant-level realization rates by control type and event date. The figure also provides gray bars representing the interquartile range, which represents the range between which half of the values lie.

In terms of the average of participant realization rates, the picture is very similar to the aggregate realization rates. However, the variability underlying those average values—as depicted by the width of the interquartile ranges—says a lot about the reliability of actually counting on those impacts. For the automated control participants, the bottom of the interquartile range is across all events and represents a realization rate of around 80% at the lowest, which means that 75% of the participants are achieving at least 80% of the nominated load reduction. In contrast, the manual control participants have a 25^{th} percentile that is more often around a 20% realization rate. On average they do not perform that differently, but there is far more uncertainty in their levels of curtailed load.

Figure 3-34: Average of Participant Realization Rates by Event Date

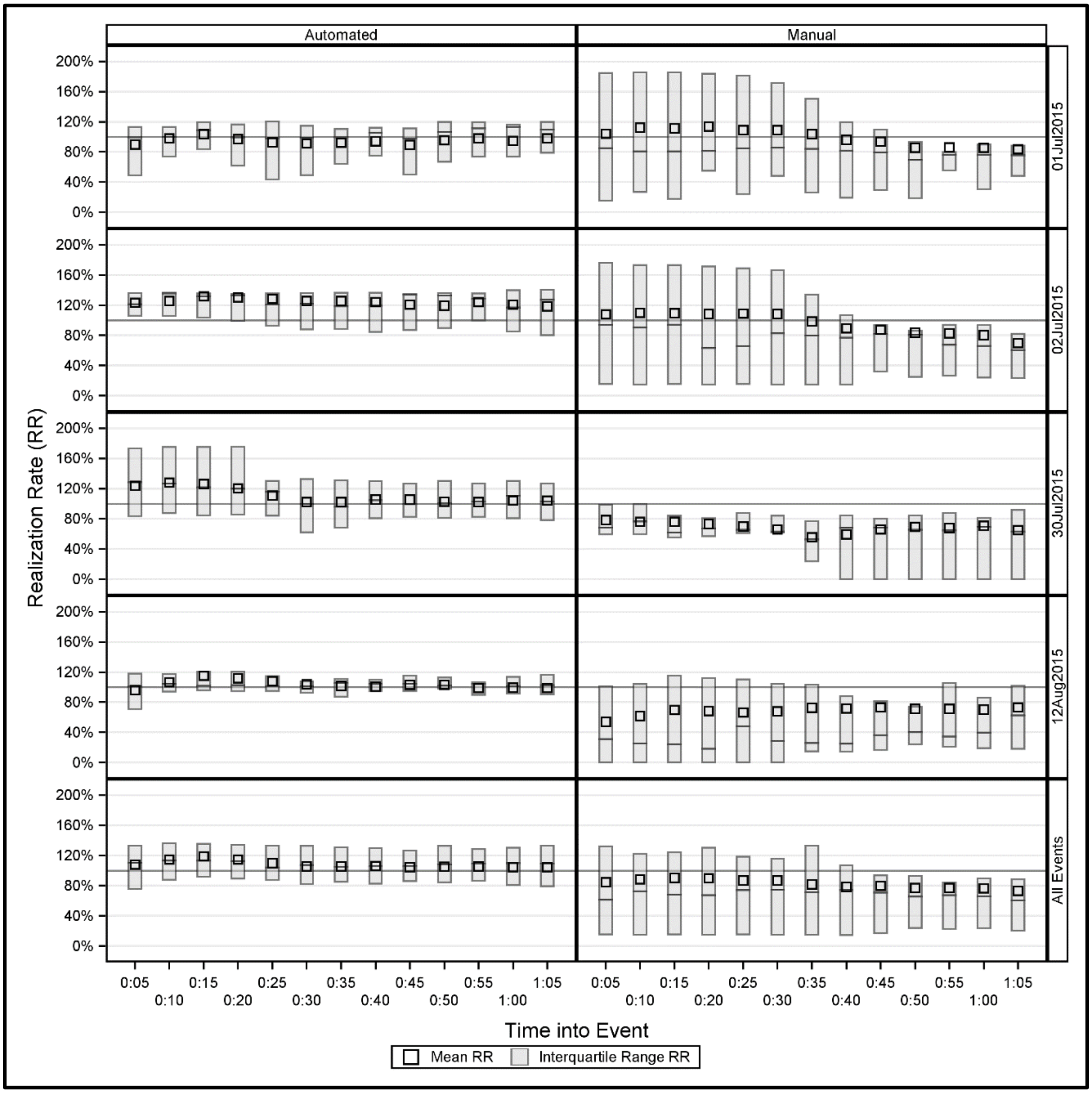
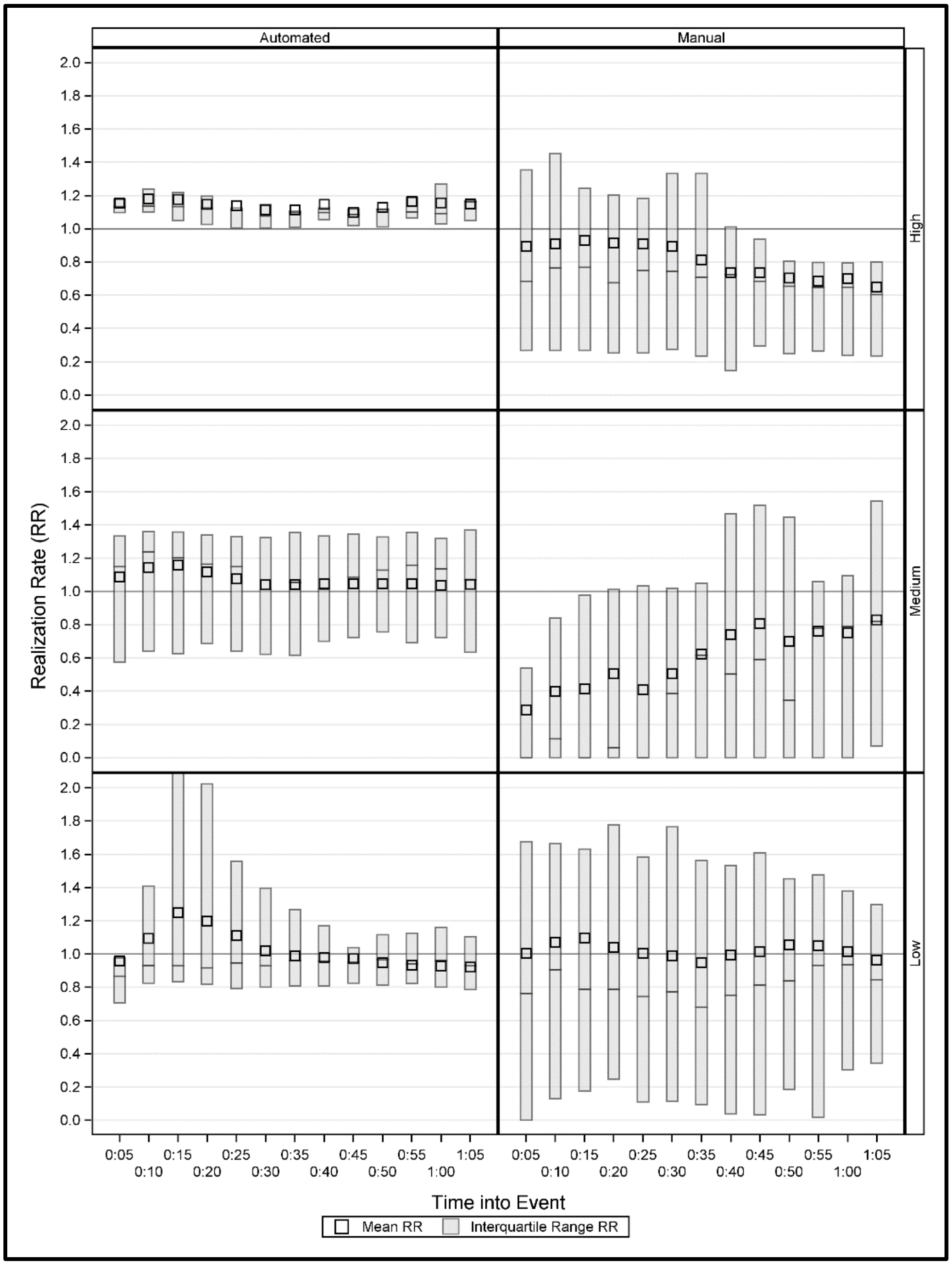


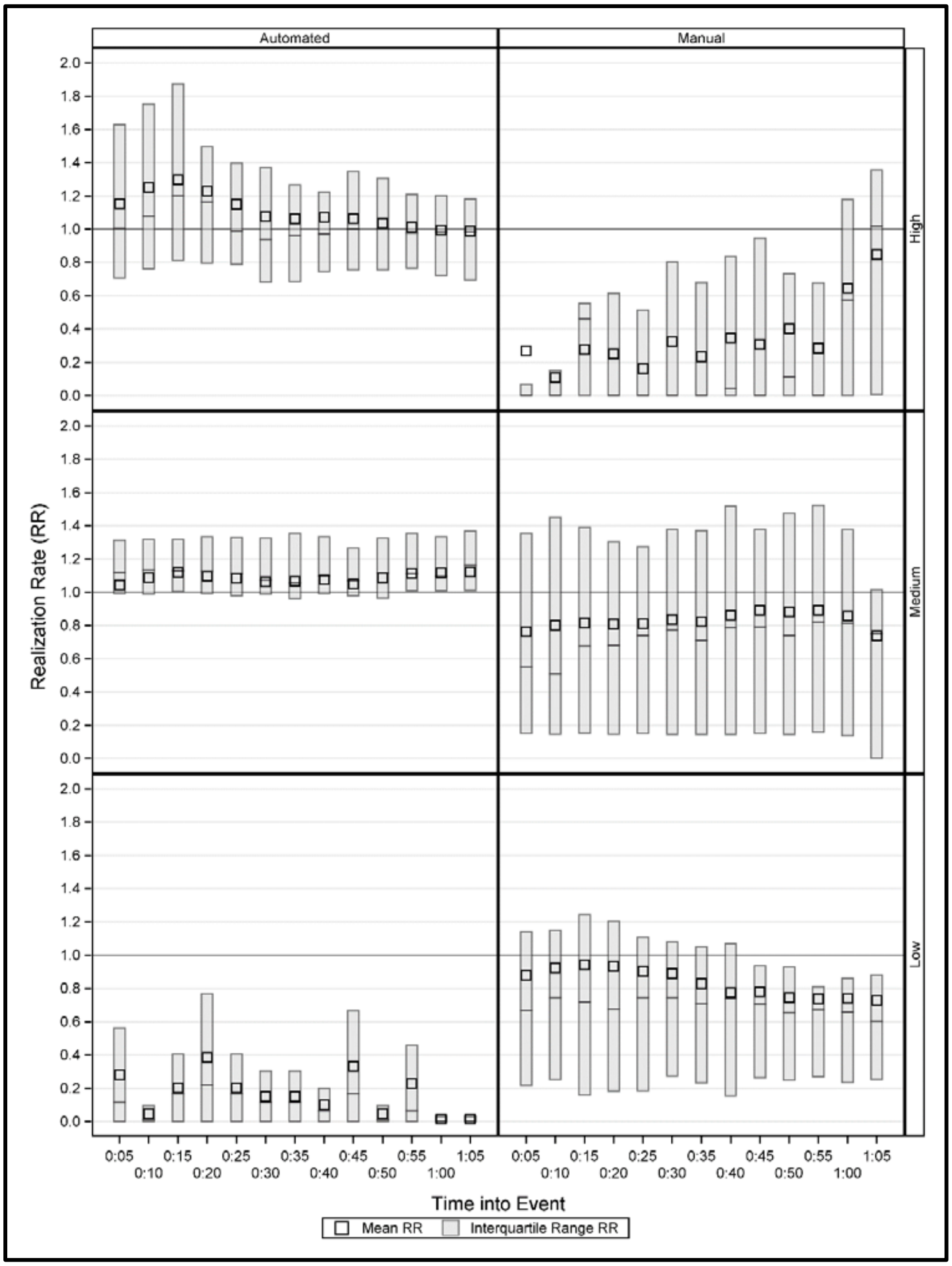
Figure 3-35 and Figure 3-36 show the realization rates for all events based on the variability and temperature sensitivity groups, respectively. One caution is that some of the frames are based on very few participants (see Table 3-17), but there are still some results of interest. For example, for the variability groups the comparatively higher realization rates associated with the automated participants is still evident, but the breakout does show that this is not perfectly consistent. The low variability sites, which are about evenly split between automated and manual curtailment, are fairly comparable in terms of average realization rates, though he automated group still exhibits far less variability. Additionally, when one considers that the proxy event analysis showed that these low variability participants had more accurate baselines, it means that the comparison of these realization rates is less likely to be distorted by inaccurate baselines.

Figure 3-35: Average of Participant Realization Rates by Variability Group



There are some features worth noting with the temperature sensitivity groups as well. For example, the automated curtailment with low temperature sensitivity participants, the realization rates over the intervals are low and erratic. And while this is based on the events for just one participant it does show that there are poor performers even among those with automated curtailment. Another interesting result is that there is more variability in the realization rates for participants with high temperature sensitivity and automated curtailment – 13 overall – relative to the overall group of automated curtailment participants.

Figure 3-36: Average of Participant Realization Rates by Temperature Sensitivity Group



3.3 Recommendations and Opportunities for Improvement

The load analyses presented above have potential implications for the program in several areas.

Beginning with the characterization of load, there was clear heterogeneity among participants in terms of both variability and temperature sensitivity. On its own this finding has little immediate relevance, but the comparison of baselines using the proxy event day analysis showed that these characteristics have a meaningful relationship with the accuracy of baselines. In general, the estimated impacts of those participants with high load variability and/or low temperature sensitivity are potentially highly inaccurate.

One recommendation based on these findings is that this characterization should be conducted seasonally on all existing participants to be better informed about the overall reliability of estimated load reductions, which could help guide program change. For example, if at some point too many participants in the program exhibit less than ideal load characteristics, it might be necessary to consider alternative settlement approaches. The characterization is straightforward, so a second recommendation is that it might be worthwhile to characterize potential participants as part of a screening process to identify and target particular customers. The third recommendation, but one that would require far more substantial changes to the program, would be for PGE to require for these participants that a firm service level be achieved, such as with PGE’s Firm Load Reduction Pilot program, rather than a specific amount of load to be shed.

In terms of the alternative baseline methods, there were two main findings. First, baseline methods can mitigate some of the issues with inaccuracy, but not substantially. Second, although there were clear cases where one baseline method performed better than another, there are only a few participants where the best baseline method was consistent across events. The comparison of adjustments not only found minimal differences between the additive and multiplicative approaches, but that in a substantial share of cases and unadjusted baseline performed best.

Our recommendation based on this analysis is that unless there is some substantial change in the composition of program participants, the program can continue with the current settlement baseline with no concerns. While a regression baseline could perform better in some cases, the current settlement baseline’s ease of implementation and explanation give is the clear advantage. The use of a multiplicative adjustment is a feasible change that PGE may wish to consider if it is more comfortable with this baseline adjustment approach, but the analysis showed that it is not going to make a significant difference in the program’s estimated impacts or settlements for that matter.

Finally, the analysis of response times showed that those participants with automated curtailment not only had higher and more immediate realization rates, but that their impacts had far less uncertainly. This finding is not surprising, but it is an important validation that there are performance issues with manual controls and it highlights the importance of automation. The recommendation is that PGE should prioritize maximizing participation for sites where automated controls are feasible.

4

Program Implementation

This section presents the evaluation of the implementation of the Energy Partner program. Findings from this evaluation are divided into two phases. Phase I represents the evaluation activities conducted during the first three seasons of program implementation. These findings have already been presented in the first evaluation report. Phase II includes the new evaluation activities that were conducted on behalf of Seasons 4 and 5.

4.1 Overview of Program Goals

The program is not expected to meet its program goal of 25 MW by 2017. The program had achieved 87% of its goal (13MW of 15MW) as of the end of the evaluation period in December 2015.

4.2 Customer Outreach and Enrollment

4.2.1 Status of Program Outreach Efforts

As of the August 2015 nomination report submitted by EnerNOC, there were 27 participants (i.e., enrolled customer organizations), representing 46 participating facilities (i.e., unique participating locations). One customer officially dropped out of the program before the start of the third season. Two customers who did not officially drop out but reported that they were unlikely to continue participation have been retained in the nomination report but have been nominated at 0 kW. These figures are summarized in the table below.

Table 4-1: Participation Overview, as of August 2015 Nomination Report

Status	Number of Customers	Facilities Represented
Participants	27	46
Officially Dropped Out	1	1
Unlikely to Continue Participation	2	2

4.2.2 Outreach Approach

Awareness of Demand Response among PGE Customers

Phase I (Seasons 1 through 3)

During the program rollout, the greatest barrier was the lack of awareness regarding the program and demand response in general. PGE customers were less familiar with demand response programs compared to customers in other states that have had demand response programs for several years. Because of their lack of familiarity, PGE customers were more likely to refuse participation based on unsubstantiated fears, such as losing control of equipment or shutting down facilities without consent. As a result, the sales cycle has been longer because PGE customers require more education and outreach. On the other hand, customers who were aware of demand response were likely to have learned about it through participation in associations, such as Energy Trust of Oregon, or through participation in demand response programs in other states.

Phase II (Seasons 4 and 5)

While customer awareness of demand response has increased since the program's launch, awareness is still not at the level encountered in mature markets, such as California. PGE staff mentioned an anecdote in which a potential Energy Partner participant was so skeptical of program outreach, that he stopped communications with EnerNOC staff until he could independently verify the legitimacy of the program. On the other hand, a PGE customer who had previous experience with demand response in California, had no apprehensions and readily sought out demand response. A PGE staff member cautioned that any comparisons between the PGE and mature markets should be limited, as the sales cycle can be much longer in the PGE territory. He continued, "*Introducing a new marketing concept is hard work, so comparing it to areas with higher awareness and different pricing structures, isn't a fair comparison, because in territories with more awareness, the same amount of work would have yielded more success.*"

To improve awareness, PGE staff have conducted outreach at events, such as one organized in 2015 by the Northwest Food Processors Association where PGE staff networked with control vendors and engineering firms. PGE communicates with these partners to keep them informed of program offerings and how demand response could benefit their customers by offsetting the cost of a controls and/or energy management systems. PGE expects to do more of this outreach in 2016.

Marketing Message

Phase I

In the early stages of the program, EnerNOC and PGE coordinated to craft a customized program message that reflected demand response in a positive light by focusing on sustainability and improved grid management, rather than messages about preventing blackouts and avoiding grid instability. To attract customer interest in the program, Key Customer Managers (KCMs) encouraged customers to think about program participation as a way to keep energy costs stable by avoiding the need for PGE to expand its energy capacity. KCMs also stated that the financial incentives of participation may not be large enough to interest all customers so they must find other ways to appeal to their customers, such as promoting the social benefits of being a good community partner.

Phase II

PGE recently completed a marketing study to identify how to best package key program messages (e.g., sustainability, financial benefits, social good, etc.) to the target audience. The results of this study showed that the group of messages was appropriate but that the loading order of these messages varied depending on the audience. Some of these findings were counterintuitive. For example, a staff member in the financial department might be more interested in retaining control of facility operations rather the economics of participation, whereas a facilities manager might be most interested in the financial benefits. PGE intends to continue to fine-tune their marketing strategy.

Pool of Potential Participants

Phase I

According to EnerNOC, the limited portfolio size of potential participants was the main reason that the program has not met its goals. According to EnerNOC, "*When we first bid on the program, EnerNOC didn't fully understand the market and its size, so we didn't understand the market potential and portfolio characteristics.*" Of a population of 16,617 meters, only 610 meters pre-qualified on the basis of having at least 200 kW of average load. From this pool of pre-qualified meters, several customer types were disqualified on account of being a poor fit for the program. School districts do not make ideal candidates because their hours of operation do not coincide with peak periods (e.g. 4 p.m. to 7 p.m. in the summer). Commercial offices also do not have hours of operation concurrent with peak periods, and have a limited ability to curtail. Furthermore, commercial office customers often lease their buildings so that enrollment may require the cooperation of the leasing company as well. Another issue is that the PGE territory has many high-tech companies, which are challenging to enroll because they may have strict operating procedures that preclude the ability to curtail during event hours.

At the onset of the program, EnerNOC also did not fully appreciate PGE's desire to manage outreach to key accounts. PGE maintains a high level of involvement with managed accounts, who may only be contacted by EnerNOC staff after a KCM has determined customer interest in participating. EnerNOC reported that indirect access to these customers slowed program growth in the first two seasons. For example, the program's "low-hanging fruit" is industrial customers, as these customers are likely to have large loads and the ability to curtail on a consistent basis. However, customers in this small group are more likely to be managed accounts that require an introduction from a key customer manager.

On the other hand, the ability of KCMs to leverage personal relationships with customers has replaced EnerNOC's need to rely upon the industry partnerships that are a necessary component of programs implemented in other territories. In the third season of program implementation, EnerNOC also began increasing outreach to unmanaged accounts, which may be contacted directly by EnerNOC without a KCM referral.

Phase II

According PGE, some of the assumptions used to estimate the pool of program candidates led to an overestimation of eligible participants. For one, a large end-user may be part of the Portland municipal area, and therefore included in the regional potential study, but is ineligible for participation if it receives service from a provider other than PGE. In one such case, a customer with 4MW of load was included in the potential study even though it was ineligible for the program because it electric service from a municipality. Another false assumption in estimating the potential for demand response in PGE's service territory is that the methodology used did not take into account that some of the largest end-users are direct-access customers, who are ineligible. As the Energy Partner is a generation-avoidance program, these customers are not considered potential program candidates.

To increase enrollment levels, PGE has launched several outreach initiatives to increase customer enrollment. In May 2015, the program also began offering distributed generation customers the opportunity to participate. Several large end-users began participating in the fifth season on account of this initiative.

Another practice is that PGE now provides EnerNOC with a blind pull of usage data (i.e. discrete load profiles without identifying customer characteristics). EnerNOC reviews this data to identify load profiles that would be a good fit for participation and then PGE matches the profiles with customer names in a way that preserves customer confidentiality agreements.

PGE has also begun providing financial incentives to KCMs who recruit large end-users. A monetary incentive of $1,500 is provided for the recruitment of end-users with 750 kW of load, and a $750 incentive is provided for end-users of 500 kW of load.

Since April 2015, PGE has also given EnerNOC permission to contact all but the few PGE customers who have adamantly refused participation. As a result, EnerNOC plans to revisit managed accounts who initially refused to participate in earlier seasons to reassess their interest in demand response and to see if anything has changed.

4.2.3 Factors in the Customer Decision to Enroll

Phase I

Customer Motivations and Concerns

Customers cited two main factors in the decision to participate – the financial incentive and the social benefits associated with demand response. However, customer perspectives varied in how they weighed the respective benefits of these two motivating factors. Some customers placed more value in the program's social benefits, such as "*being a good community partner,*" and "*helping reduce costs related to grid infrastructure.*" Other customers saw equal value in the social and financial benefits, and according to one customer, "*It's an opportunity to save money for the company and give back to the community by keeping utility costs down*." On the other hand, other customers were primarily motivated by the financial incentive, even if they were grateful for the social benefits provided by the program. An industrial customer stated, "*While the social and financial benefits are both important, management is really just interested in the financial aspect*."

Customers were also concerned about how curtailment might affect facility operations or compromise the comfort of its occupants. Discussions between facility staff and the decision-makers had to resolve any possible impacts on daily operations before program participation was considered. These discussions addressed operations needs pertaining to lighting, refrigeration, or battery charging equipment and how program hours might coincide with uninterruptible facility processes. However, customers reported that EnerNOC reassured them by focusing on the program's flexibility and the fact that curtailment was not obligatory during events. One customer said, "*It was pretty straightforward, because we just looked at the easiest things that we could do with zero impact on our operations with the understanding that we could decline participation at any time*."

Some customers, such as those in process manufacturing, presented challenges as they may be reluctant to shut down operations for extended periods of time. EnerNOC worked with these customers to develop unobtrusive curtailment strategies. In one such example, a manufacturing facility adopted a strategy that temporarily shut down forklift charging stations, so that curtailment had minimal impact on necessary operations. In another example, a water authority stated that the decision to participate was more complicated because it posed a small risk to its service territory. The customer stated, "*The real risk was that it would cost our ratepayers, in which case it would have violated our ethics to participate in the program.*" The customer stated that these risks had to be considered, especially in extreme circumstances when water supply would be needed to combat wildfires.

Phase II

The Role of Energy Trust of Oregon in the Customer Decision to Participate

Several customers reported that their decision to participate was influenced by activities associated with Energy Trust of Oregon (Energy Trust). To follow up on these reports, the evaluation team conducted interviews with Energy Trust to explore its role in introducing demand response programs to customers and how Energy Trust and the PGE Energy Partner program might collaborate in the future.

The mission of Energy Trust is to administer energy efficiency programs on behalf of the Oregon IOUs. Discussions with Energy Trust staff indicated that any interaction with the PGE Energy Partner program occurred incidentally through Strategic Energy Management (SEM) workshops. These SEM workshops convene six times per year and involve cohorts of 8 to 12 companies of various sizes in a given industry. Of the 120 SEM workshop attendees, 90 are PGE customers. On behalf of Energy Trust, contractors provide year-long training to SEM cohorts, facilitate peer-to-peer discussions, and visit participants with the goal of improving their operations, maintenance, purchasing practices, and policies with respect to energy efficiency.

At the launch of the Energy Partner program, a PGE staff member presented the program at an SEM workshop. Energy Trust reported that cohorts discussed demand response opportunities amongst themselves and ultimately viewed the program with mixed impressions. According to Energy Trust staff, some attendees tried to participate but reported frustration that they did not meet eligibility requirements in terms of demand and rate schedules. Consequently, these customers gave feedback to Energy Trust that the presentation was not a valuable use of their time. Energy Trust also noted that SEM cohorts are not set up according to demand size and rate schedules but rather are comprised of many disparate types of end-users.

As far as reasons for participation are concerned, a staff member at Energy Trust found it unrealistic that SEM attendees would be motivated to participate for the system benefits that the program provides. According to the staff member, system benefits, such as reduced demand during peak periods and reduced grid infrastructure costs, do not figure directly into the customer decision-making process. Reported feedback from Energy Trust customers indicates that customers want a value proposition that the program should fairly compensate them for the effort involved in disrupting operations. According to program staff at Energy Trust, there have been mixed reviews from customers about whether the current program achieves this objective. Furthermore, Energy Trust indicated that SEM cohorts also require assurance that they can retain their autonomy over their operations.

Despite the concerns voiced above, Energy Trust reported that it is very open to collaborating with the Energy Partner program, and indicated that SEM workshops could be a valuable outreach platform. A staff member said that SEM cohorts make ideal demand response candidates because they are sophisticated consumers of energy with an interest in finding added value in terms of energy management. Members of SEM cohorts are also more likely to have an existing knowledge of the benefits of energy management, familiarity with their energy consumption data, onsite staff educated in energy decision, and may have already taken steps to get an aligned corporate commitment to energy improvements.

EnerNOC is open to the idea of working with Energy Trust on any potential coordinated outreach plans, such as giving presentations to participants of their SEM groups. EnerNOC believes that coordinating with Energy Trust would result in more customers, especially as Energy Trust offers incentives for energy managements systems, which would serve as an opportunity to introduce the program. EnerNOC would defer to PGE to take the lead in leading any potential coordination strategy, but if coordination occurred, EnerNOC would like to pre-identify customers that are eligible in terms of average load and hours of operations, so as to focus efforts on customers who are best suited for demand response.

While Energy Trust is very open to collaborating on the Energy Partner program, a staff member made two stipulations: 1) PGE should be very up front and direct about who is being asked to enroll; and 2) PGE needs to make the value proposition very clear to clarify the effort required and the benefits of participation. Any future collaborations between the PGE Energy Partner program and Energy Trust should seek to resolve these issues before reaching a joint plan.

PGE views a partnership with Energy Trust as a strategic fit that would benefit both parties. While Energy Trust offers programs that provide building energy management controls that can enable curtailment, the Energy Partner program provides additional incentives that could offset the cost of integrating with such equipment. According to PGE, the best strategy would be to pre-identify customers who are a good fit for the program, and share this data with Energy Trust to coordinate a strategy. However, PGE admits, "*Early on in the program, PGE was not actively promoting working with Energy Trust as much as we should have, but we've straightened it out and are moving forward*."

4.3 Overview of the Commissioning Process

During the first seasons of program implementation, PGE staff characterized the commissioning process as slow and in need of improvement. However, starting in the third season, an increased focus on the individual steps of enablement, especially meter installation, has made the overall process more efficient. According to EnerNOC the overall timeframe from project start to completion was reduced from 23 weeks in the first season to 12 weeks by the end of the third season. The following subsections provide an overview of the steps involved in the commissioning process.

- **Delivering a Proposal to the Customer.** Once the customer gives approval to share energy-usage data, EnerNOC evaluates potential curtailment strategies based on energy usage and delivers a proposal to the customer for signature.
- **Development of a Curtailment Plan.** To assess a customer's potential for load reduction, EnerNOC conducts a walkthrough of facility operations and examines its equipment during a qualification visit. A curtailment plan is developed for each customer according to what equipment may be shut down during program hours while minimizing the impact to operations.
- **Installation of Data Collection Equipment.** PGE installs pulse-meter equipment on the customer meter to enable the collection of interval load data. Following the installation of pulse equipment, EnerNOC's equipment is installed by a third-party subcontractor. In the first two seasons, delays in hardware installations occurred, as the subcontractor had been anticipating more sites and thus deferred site visits in order to schedule multiple sites in clusters to minimize scheduling costs. However, EnerNOC resolved the issue with the installation subcontractor so that such delays did not persist in to subsequent seasons.
- **Acceptance Testing.** EnerNOC establishes and verifies communication between the EnerNOC control center and the customer's control systems or energy management system. After an acceptance test is conducted to ensure that the equipment is curtailing load as expected, EnerNOC reviews the results with the customer and suggests methods of improving future performance, if necessary.

4.4 Participation in Events

4.4.1 Notification and Response Time

Phase I

In general, customers received notification one to three hours before a curtailment event begins. One customer expressed a preference for earlier notification before events and said, *"If we had at least five hours or 24 hours, we could easily meet the requirements. If we know ahead of time, then we can plan ahead."* In terms of notification method, customers found the system of email, text and phone call notifications to be sufficient, if not excessive.

Phase II

Customer interviews also sought to determine how many participants are able to curtail within a 10-minute notification period. While two-thirds of respondents stated that it was possible to curtail within ten minutes of notification, most of these customers said that a timely response was dependent on one or more conditions. For example, some customers could only curtail load within ten minutes if the facility manager was onsite and available at the time of notification. Several customers indicated that they could curtail in a 10-minute period provided that production processes were inactive at the time of the event. The ability to curtail in a 10-minute period also varied according to response method. Approximately 83% of automated-response customers (5 out of 6 customers) and 58% of manual-response customers (10 out of 16 customer) said it was possible to curtail within ten minutes of notification.

For many customers, prompt curtailment was not a yes/no outcome, but a matter of degrees. Some customers are able to curtail, but only a portion of their nominated demand, within the 10-minute period. One such customer said, *"Some equipment can be turned off in 10 minutes, but the main contributor to our curtailment plan needs an hour to go offline."* For other customers, the brief notification period reduced their likelihood (e.g. 50%) of being able to curtail. This was especially true among customers for whom curtailment entails not starting equipment rather than shutting down equipment. Such customers especially benefitted from a longer notification period. According to a production manager, *"A 10-minute notification period makes it more likely that we've already started running the equipment, but if it's a one- to two-hour window we have more time to look at our production need and determine if we can participate."*

Other customers noted that being pre-notified several days in advance was an important factor in the ability to curtail within ten minutes. A water bureau indicated that pre-notification increases the likelihood of his facility being able to curtail from 50% (without pre-notification) to 90% (with pre-notification). This respondent said, *"These water plants are designed to stop and start, but to do so requires a lot of effort because there are a lot of biological and chemical processes in effect, so we don't want to shut down in the middle of a run. If we expect an event, we can fill the reservoir so that we can terminate service."*

Considering all the conditions stated above, less than one-fifth of respondents indicated that they could unequivocally curtail the full amount of nominated demand in a 10-minute period. And even so, these customers stated a strong preference for a 15-30 minute notification period. One customer said that *"While we can live with 10 minutes, we prefer more time, because 10 minutes is too much pressure."* One-third of customers are not able to curtail within a 10-minute period under even the best circumstances. These customers cited the requirements associated with manual shut down and ramp down procedures as the main reasons why they could not curtail in ten minutes.

PGE has not yet tested the viability of a 10-minute notification period because unseasonably warm winter temperatures have not present ideal conditions for testing. Ideally, testing would occur during a peak demand period in the midst of a cold snap. However, PGE still intends to perform such a test even if the weather does not cooperate. EnerNOC stated that while it will be challenging for some customers, others such as Home Depot and Albertson's are expected to respond automatically within 10 minutes. EnerNOC acknowledges that the portfolio was developed without discriminating based on required response time, so it is still learning about customers' ability to do so in a short time frame.

4.4.2 Customer Experiences with Events

Phase I

While customers reported that their experience with demand response events met expectations, several customers reported incidents of "growing pains" with the program. One customer said, "*When we started participating, we found that we couldn't switch off as much power as anticipated because the circuit breakers didn't control the equipment as expected.*" Another customer indicated that miscommunication occurred when there was a shift change during the course of an event, and the equipment was not restarted as it should have been. Customers also cited deadlines, or process requirements, as the main reasons they chose not to curtail during certain events. *"We prioritize our customers and workflow over participation,"* said one customer, *"so if it's not convenient for a particular event, we just don't participate*."

Another topic of concern raised during discussions with PGE and EnerNOC was the issue of program hours. Some program hours are problematic in that demand peaks are likely to occur during the hours of 5:00 p.m. to 7:00 p.m., a time when many businesses in the PGE territory are ramping down. For example, one customer was not able to participate in most of the events because they were called when production and processes are shutting down for the day. While the lack of overlap in customer operations and peak demand does not hinder growth of the program in terms of customer enrollment, it does reduce a customer's ability to participate in such an event.

The ability to curtail was found to vary on a seasonal basis for some customers. For example, water authorities indicated that their ability to curtail in the summer is limited as it coincides with the seasonal peak demand for water. During the winter, however, water authorities indicated that they could curtail much more load. In another example, curtailment during winter afternoon events posed a concern for one customer. *"In the summer, we can curtail our lighting because we are able to rely on our skylights, but when it gets dark early during the winter months, people wouldn't be able to see if we curtailed*." Another customer reported lowering its nominated demand for the winter because most of the facility's energy use stems from refrigeration equipment. However, at least one customer found a way to make up for the gap in nominated demand during the winter. This customer noted that during the winter season, it supplements load reduction by manually shutting down its battery charging system in order to ensure that it meets its nominated demand.

Phase II

Only one event was called during the Winter 2014/15 season, so while customers had fewer experiences to report upon than in previous seasons, they did provide some insight regarding how the date of the event (December 30) made participation difficult. In fact, this event had the second lowest realization rate (68%) of any event during the five seasons of the evaluation period. One customer stated that while it is easier to curtail during the holiday season because it is a slow production period, the customer's baseline load is also lower. Another customer indicated that his organization was unable to participate due to monthly production goals. He said, "*We couldn't participate at the end of the month because we were behind our production schedule and we would have to make up any lost production later on in the month.*" If the event had been called earlier in the month, the customer would have been more likely to participate, because there would have been more calendar days to make up for lost production. Also, at least one customer was unable to participate on account of the time that the event was called (6:00 p.m.), which occurred after his facility's hours of operation had already ended.

The Pacific Northwest experienced one of its hottest summers on record in 2015, and the weather was a common theme in discussions with program participants. For example, customers with refrigeration equipment had difficulty curtailing load during events called on hot days. One of these participants said that while his facility exceeded expectations in terms of curtailed load, he was very concerned with how his facility would maintain cold temperatures during the course of the event. Another participant with refrigeration equipment said that the heat wave affected his ability to keep product cold, so he had to discontinue participation for the rest of the summer. He said, "*The summer events are just too long for us to continue participating, even considering that we reduced our targeted curtailment period to two hours.*" This customer, however, noted that he would resume participation in the future as a winter-only participant.

A participating wastewater facility reported that they were not able to curtail as much as expected during the heat wave on account of the temperature required by the biological processes present at the facility. He said, "*The weather in July was too much of an impact on the system, especially during the 3 p.m. to 5 p.m. time period*." He also noted that his facility was not able to participate for the remainder of the summer season.

Despite these issues, the customer portfolio still managed to provide 86% of nominated load for the season. According to EnerNOC, this percentage represents a moderate level of success, considering that actual program experiences did not meet the original expectations of the program.

For example, water authorities reported positive experiences with the events called during the heat wave even though they expected themselves to perform poorly at first. As part of their curtailment plan, these facilities pump water during off-peak hours the night before an expected event to provide water. According to one water board, "*It's easier to participate after the first couple of times, as we've gotten better at curtailing, and gone through the growing pains of learning how to reduce demand while maintaining water levels.*"

4.5 Customer Satisfaction

4.5.1 Satisfaction with Payment Received

<u>Phase I</u>

This evaluation sought to determine whether these financial benefits aligned with customer expectations. The customers who had conservative expectations of the amount of money that they would receive usually participated on account of the social benefits that the program provided. A customer who received $400 was satisfied, although he said, "*It wasn't much money, but it was made clear at the outset that this program isn't something that would generate a lot of dollars.*" Other customers were less concerned about the one-time financial benefits of participating in a season than they were in seeking long-term, sustainable savings. One such customer said, "*By participating, we identified equipment that we can turn off, not just in response to an event, but in general, so capturing these sustainable savings are more meaningful than receiving an occasional check*." On the other hand, a customer who received a check worth $37 was disappointed with the amount received and said, "*I was under the impression participation would be worthwhile, because we delayed production to participate and the amount of the incentive was not even enough to cover my time*."

There was also uncertainty regarding how much money participation yielded, as some customers were unsure of how or when payment would be disbursed. One customer indicated that payment is delivered to an accounting department. He was therefore unaware when payment is received. In regard to payment method, one customer said, "*It wasn't made clear when a check would be sent, or if a credit would appear on my PGE bill*." Nevertheless, one of the most common recommendations by customers cited was the need for more communication with customers in regards to payment amount and timing.

<u>Phase II</u>

Interviews with customers after the fifth season echoed the same sentiments expressed in earlier evaluation periods. While customers with low expectations of payment were generally pleased with the amount received for curtailment, customers with higher expectations reported concerns. One customer said, "*We participate to promote the program, so we don't have any expectations of payment and any money that we receive is a bonus*." A customer with greater expectations said, "*EnerNOC projected that we could earn thousands of dollars if we participated in ten events in a season, but that hasn't happened, so we only received a payment of $156*." Another customer stated, "*I wasn't impressed and I'm concerned that the payment amount doesn't justify the amount of labor required to shut everything off and turn everything back on.*"

One customer said that he misunderstood how payments were calculated based on meeting nominated demand goals. He said, "*It should have been made clear to me at the beginning that* *there was no payment for partial reduction*." The customer explained that he declined to participate in subsequent events because his facility wouldn't be able to meet the nominated demand goal.

On the other hand, at least five customers indicated that they still had no knowledge of the payment amount or whether they received any payment at all. Currently, earnings information is made available approximately six weeks after the end of a program month. EnerNOC understands that customers want to learn about potential payment as soon as possible, and suggested that it would be possible for them to communicate payment via email with customers after invoices have been processed.

After the fifth season, PGE reevaluated the payment structure, and realized that some assumptions made during the program's inception did not align with actual conditions. One of these assumptions was about the number of events that were expected to be called. Warm weather in recent winter seasons created a situation in which fewer events were called than would have been anticipated otherwise. After a frank discussion of how much compensation customers received, it was deemed that customers were not being adequately compensated for the time and effort involved in participation. The original program design anticipated a greater number of dispatch hours, so the payment formula weighted the energy payment more than the capacity payment. The new formula, which will be implemented this year, will pay customers more by rewarding them based on the capacity provided each month rather than their performance in a season (i.e. increasing the capacity payment and lowering the energy payment.) Furthermore, capacity will be based on a customer's average performance over the month rather than basing it upon the lowest two performances in a season. This revised formula is expected to increase enrollment.

The program has also taken measures to deliver payment to customers more quickly. Due to a misunderstanding of the contract language, EnerNOC's practice in previous seasons had been to bill PGE 30 days after the end of a season. However, after discussions with PGE, it was made known that the correct billing practice is for EnerNOC to bill PGE within a week of month's end. This current practice allows PGE to pay EnerNOC sooner and more frequently so that customers may in turn receive more prompt payment from EnerNOC.

4.5.2 Satisfaction with EnerNOC Software

Phase I

Most customers found the software and data provided by EnerNOC to be interesting, but of limited utility. Customers with their own in-house monitoring systems, such as SCADA, expressed a preference for their systems over the EnerNOC product. However, one customer indicated that the data helps his organization understand the trends in their energy cycles, which would be useful if he wanted to schedule production around demand peaks and troughs. "*It hasn't changed our business model yet,*" the customer said, "*but we now have access to that information if we wanted* *to change our schedules.*" One customer, however, said that while aggregate power usage is interesting, it is not very helpful in managing energy usage without sub-metered information for individual equipment. He said, "*If we had numbers on individual machines," the customer said, "it would enable me to schedule around my peaks and valleys in energy usage.*"

Phase II

Previous evaluation research showed that customers were not proactively researching their performance after an event, even though they have had the ability to do so as soon as one hour following an event. To improve this situation, customers now receive an email 48 hours after an event with a link to their performance summary. Also, at the end of each season, participants now receive an email to visit the EnerNOC portal to view a payment estimate. In the past, customers had the option to view the payment, but only if they did so on their own initiative. This new strategy should alleviate any customer confusion regarding payment delivery. Although the topic of software was not discussed with Energy Trust during this evaluation, past communications between Energy Trust and PGE suggested that it would be a good fit for SEM customers.

4.5.3 Overall Satisfaction with Program Experience

Phase I

In the first seasons of program implementation, customers were generally mixed in their reviews, ranging from *satisfied* to very *unsatisfied* (see Table 4-2). Five of the eleven customers interviewed indicated that they were generally satisfied with their program experience. These customers enjoyed the simplicity of the program and the fact that curtailment was not obligatory. Two customers were undecided and said that it was "*too early to say*" whether they were satisfied with the program. Four customers reported some source of dissatisfaction and cited issues pertaining to lack of information, small incentive payments, and problems with equipment installation.

Table 4-2: Customer Satisfaction with Energy Partner Program, Phase I

Level of Customer Satisfaction	Percentage of Respondents (n = 11)
Very/Somewhat Satisfied	45%
Dissatisfied	36%
Undecided/Too Early to Determine	18%

Phase II

Most of the participants who were interviewed after season five indicated that they were either *very satisfied* (60%) or *somewhat satisfied* (30%) with their experience in the Energy Partner program.[1] Several of these customers reported they enjoyed being community partners and that participation takes little effort. Only one participant said that he was dissatisfied (5%). This dissatisfied customer said, "*The program is too much effort for too little gain*." He also said that while he would not recommend the program to a production facility such as his own, he would recommend the program to a cold storage facility. Another customer who had not received payment said he was unsure of his satisfaction level (5%), as he would base his response on the amount of money issued for participation. Results are reported in Table 4-3.

Table 4-3: Customer Satisfaction with Energy Partner Program, Phase II

Level of Customer Satisfaction	Percentage of Respondents (n = 20)
Very Satisfied	60%
Somewhat Satisfied	30%
Dissatisfied	5%
Undecided	5%

Drop-Outs

At the time of this report, one customer had officially dropped out of the program and two customers expressed their intentions to drop out. Generally, these customers reported that the economics of participation did not justify the continued effort required of curtailment.

Likelihood of Continued Participation among Current Participants

There were no new dropouts identified during the most recent round of interviews as all continuing participants said that they were either *likely* (25%) or *very likely* (75%) to continue participation in the Energy Partner program (see Table 4-4). One of these respondents said he planned to continue participating because "*There are no drawbacks and everybody benefits from the program*."

However, some customers stipulated conditions on their future participation. For example, several customers with refrigeration equipment said that they would participate only in the winter seasons, and not the summer seasons. Other customers said that they would stay in the program, but were increasingly reluctant to curtail. One such customer said that he would be less likely to participate considering that he would not receive payment for curtailing only a portion of his nominated load. Another customer expressed a similar sentiment and said, "*EnerNOC told us that we would get paid for reducing whatever energy we could, but they didn't tell us we had a target to meet.*" This

[1] Note that customers who indicated that they had dropped out or intended to drop out were not interviewed in Season 5, and are not represented among respondents. Also, comparisons with Phase I evaluation results should be limited, because the pool of participating respondents is not the same.

customer said he would like someone to inform him on what threshold has to be met in order to receive payment.

Table 4-4: Likelihood of Continued Participation in Energy Partner Program

Likelihood of Continued Participation	Percentage of Respondents (n = 20)
Very Likely	75%
Likely	25%
Unlikely	0%

4.6 Recommendations and Opportunities for Improvement

4.6.1 Improvements In-Place

Since the program's launch, PGE has continually made program improvements based on customer feedback, discussions with EnerNOC, and the results of evaluation studies. Over the course of the program's first five seasons, the following improvements have been implemented:

- **Bottlenecks in the commissioning process have been removed, thus reducing the timeframe required for enablement.** In previous discussions, customers identified delays in the installation of equipment, but subsequent discussions with EnerNOC staff identified this problem as a scheduling issue and undertook corrective actions. In recent interviews, new customers reported no problems with scheduling the installation visit, and on average reported a two- to three-month timeframe between enrollment and the enablement.
- **PGE now provides a list of pre-selected customers to EnerNOC based on a blind pull of customer load profiles.** To increase enrollment levels, PGE now provides EnerNOC with discrete load profiles to pre-identify potential candidates for participation. This is done in a manner that maintains confidentiality agreements regarding customer data.
- **Dispatchable standby generation customers are now eligible to participate.** In the past, dispatchable standby generation (DSG) customers were not eligible to participate, thus reducing the potential for nominated demand in the PGE territory. In May 2015, the program also began offering DSG customers the opportunity to participate. Several large-end users began participating in the fifth season on account of this initiative. It should be noted that these customers participate only by curtailing load, not by use of their generators.
- **PGE incentivizes KCMs for the enrollment of large end-users.** Program growth has been slower than expected, especially among large end-users who offer the most potential for curtailable load. In order to increase enrollment, PGE has also begun providing financial incentives to KCMs who recruit large end-users. A monetary incentive of $1,500 is provided for the recruitment of end-users with 750 kW of load, and a $750 incentive is

provided for end-users of 500 kW of load. At the time of this report, one such incentive had been awarded to a KCM.

- **Customers now receive notification to view performance 48 hours after an event.** Some customers lacked the information to determine whether participation was a worthwhile activity. Interviews with customers revealed that they were not checking their performance summary on the EnerNOC portal. The email notification acts as a reminder that they have this option available to them.
- **The time required to process invoices has been reduced, thus allowing faster payment to customers.** Interviews in earlier seasons revealed that customers lacked the payment information required to share and justify the cost-effectiveness of program participation to management. This improvement makes it more likely that customers will have timely access to information regarding payment.
- **The payment formula has been revised to provide greater incentives by rewarding customers for providing capacity rather than hourly performance.** Interviews revealed that some customers have been underwhelmed by the amount of the incentive payment received. The importance of the customer's bottom line should not be underestimated. This action seeks to compensate customers in a manner that justifies the time and effort involved in participation.

4.6.2 Additional Opportunities for Improvement

As the program continues to mature, there are still potential opportunities for further improvement. Most of the following opportunities have already been discussed with PGE:

- **Reach out to customers who have already declined participation.** Some customers have already turned down the opportunity to enroll in the Energy Partner program, but may reconsider participation now that some time has passed. PGE allows EnerNOC to contact customers multiple times, unless the customer is adamantly against further program communications.
- **Coordinate with Energy Trust of Oregon**. PGE views a partnership with Energy Trust as a strategic fit that would benefit both parties. PGE will explore developing this relationship in 2016.
- **Expand enrollment to also include customers who can only participate in some program hours.** In the past, only customers who could participate in all program hours were considered for enrollment. As a result, many customers were considered a poor fit for the program and did not receive further consideration. A new strategy would permit customers to enroll if they could just meet some of the program hours (e.g. 2 to 5 p.m. rather than 2 to 6 p.m.). This opportunity would provide the program with additional source of nominated demand.

- **Leverage AMI data to reach potential participants.** In past seasons, small end-users with less than <200 kW of load have not been considered a good fit for the program structure. However, creative ways of using AMI data could be used to enable these smaller customers to participate. For example, such customers could participate using AMI data instead of meter data. This type of strategy is still under development, and such candidates have not yet been identified.
- **Fine-tune customer messaging.** PGE marketing studies have shown that while the program offers the right set of marketing messages, the value of these individual messages varies according to the target audience. PGE continues to fine-tune and weigh the importance of various program benefits (e.g. financial incentive, not losing control of the facility, sustainability) according to the role of the target audience.
- **Develop strategic partnerships with control companies and engineering firms.** Firms that design controls or energy management systems are in a unique position to validate the value of program participation. PGE expects to develop strategic relationships with these industry partners, as they play a key role in influencing customer choices.