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April 15, 2015

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Public Utility Commission of Oregon
Attn: OPUC Filing Center
3930 Fairview Industrial Drive SE
P. O. Box 1088
Salem, OR 97308-1088

Re: **UE 272 Automated Demand Response – Phase 1 Report**

In accordance with Commission Order No. 13-172, enclosed is PGE's first report on the Automated Demand Response pilot.

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

Sincerely,

Patrick G. Hager
Manager, Regulatory Affairs

PGH:sp

cc: Jason Salmi Klotz, OPUC
Alex Tooman
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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℠ automated demand response (Energy Partner or ADR) pilot and adopted timeline. In this timeline PGE planned to file an evaluation report on the progress of the Energy Partner pilot in March 2015.[1] The report includes:

1) Status of the Energy Partner Program
2) Third-Party Evaluation (ITRON) of the Energy Partner Program

Status of the Energy Partner Program

Program growth to hit 25 MW

The Energy Partner pilot began operations in August 2013. The program has seen steady growth towards the goal of 25 MW of automated demand response resources. Table 1 shows the progress towards meeting this goal.

Table 1; Growth in Energy Partner over First Four Operating Seasons

	Summer 2013	Winter 2013/14	Summer 2014	Winter 2014/15
Customers	2	3	17	23
Nominated Demand	250 kW	300 kW	2,745 kW	6,745 kW

Although the pilot's growth has been slower than predicted, PGE is working diligently to address the slow growth by incorporating Itron's feedback and recommendations. Below we have summarized our current efforts to grow customer enrollment, participation and satisfaction.

- **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, Oregon Manufacturers Association, and the Building Owners and Managers Association (BOMA), etc.

[1] Commission Order No. 15-085 allowed an extension to April 15, 2015 for PGE to submit the evaluation report.

- **Market Education**: We have launched email campaigns to interested parties and developed industry-specific case studies and videos designed to help communicate the features and benefits of enrollment in the program.
- **Direct Meetings**: We have continued leveraging our KCMs to support EnerNOC account representatives in our outreach efforts to target customers. We have also worked to improve our targeting efforts by leveraging load profiles in initial screening.
- **DSG Customers**: After deliberation, PGE will be allowing DSG customers to enroll in the Energy Partner program. These customers have the potential to add 5 to 10 MW to the program.
- **Improved Messaging**: As part of the recommended marketing efforts from the evaluation report, PGE commissioned a market research study to address and prioritize marketing messages to different representatives within a given company. The message needs to discuss topics such as financial benefit, customer ability to control process, and sustainability.

Event Performance

The Energy Partner portfolio showed solid performance with realization[2] rates above the contractual 85% obligation. It should be noted that the realization rate represents capacity that the vendor is contractually obligated to deliver for each event. In most events, the realization rates were above 100%. Aggregate seasonal results are listed in Table 2, below:

Table 2; Event Realization Rates for First Three Operating Seasons

	Summer 2013	Winter 2013/14	Summer 2014
Number of Events	3	5	6
Average Number of Participants	2	2.4	13.7
Realization Rate	170%	135%	98%

One event (July 14, 2014) fell below the 85% realization rate allowed under the contract. This resulted from two of the largest customers not being able to participate that day and time; an

[2] Realization rates are calculated as the kW-weighted average over all events called during a season, comparing achieved versus nominated load curtailment and expressed as a percent.

issue that will be less impactful as the portfolio expands with a more diverse customer set. Overall, seasonal performance met contractual obligation.

Customer Satisfaction
Initial results showed four out of the eleven customers surveyed were not satisfied with the program due to lack of information, small incentive payments, and problems with equipment installation. PGE and EnerNOC are working to increase customer satisfaction, addressing these issues by:

- Creating better visibility for customers into their event performance, proactively providing information on the payment earned for the event performance.[3]
- Continue improving the timeliness of the customer enablement process. We have already trimmed two weeks from the process and are endeavoring to continue this progress.

Third-Party Evaluation

The primary component of this report is provided as Attachment A, which is a detailed third-party evaluation of Energy Partner through the first three operating seasons. Attachment A was prepared by Itron, Inc. and consists of two aspects: 1) survey-based research, conducted separately for all winter and summer seasons; and 2) load impact estimation, based on analysis of AMI and load data, and also conducted separately for each of the three seasons. In summary, the Itron report notes that the pilot <u>did realize</u> significant load reductions during events.[4]

Surveys
Itron interviewed the program vendor, EnerNOC, and participants from the first three seasons to evaluate customer satisfaction and program effectiveness.

- **Customer Satisfaction**: Though customers are generally satisfied, their satisfaction could be improved by speeding up the enablement process, providing enhanced event performance information and quicker access to the information on upcoming payments.
- **Program Effectiveness**: Continue looking for ways to increase the pool of participants in the program by:
    - Employing active marketing measures that not only pique customer interest but also address customer misconceptions, especially prevalent among industrial customers. Pilot staff should leverage relationships with trusted industry associations (e.g. BOMA, Energy Trust), and customers that participate in

[3] Today, customers have a portal to see event performance information and payments. PGE and EnerNOC are working to deliver the information to customers through email.
[4] Itron, Phase 1 Report, April 9, 2015, Section 3.

demand response programs in other states. KCMs may assist by leveraging the customer types that are more likely to be informed about demand response (e.g., grocery chains) and by continuing to educate customers on the nature of participation.
PGE Status: Executing

- The marketing message should continue to be fine-tuned to address each customer's individual motivations, which may include environmental sustainability, good public relations, social benefits, low transmission costs, and/or financial benefits.
  PGE Status: PGE revised marketing materials and completed a marketing study that tests message effectiveness and priority.
- KCMs should re-engage customers who have already refused to meet with program implementers. In addition, EnerNOC should establish partnerships with industry organizations, as these may provide an avenue to recruiting managed and unmanaged accounts. It should be noted that EnerNOC typically relies on these organizations while promoting the program in other service territories, but has done little of this activity while promoting the program in PGE's service territory.
  PGE Status: Executing
- Actively pursue DSG customers.
  PGE Status: Planning

Load Impacts

The Itron report demonstrates the pilot did result in significant peak reductions with solid realization rates, which were across nearly all customer segments and all events over the measured seasons. This demonstrates that the pilot should continue because it has shown potential to provide additional capacity during times of peak demand and it continues to grow to the target level.

Baseline

The event realization rate is highly dependent on the baseline calculations and methodology (i.e., estimates of customer usage to determine curtailment during Energy Partner events). The methodology used in this program is consistent with industry best practices.[5]

[5] Itron, Phase 1 Report, April 9, 2015, 2015, Page 2-2.

Conclusions and Recommendations

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

- PGE's continued efforts to increase marketing, education, KCM's and other outreach efforts, as well as targeting additional customers is needed to grow the Energy Partner pilot into a program.
- Addressing customer concerns with proactive event information and operational enablement is required. PGE and EnerNOC are working on a solution to proactively provide customers this information after each event and at the end of each season versus having to login to their personalized portal.
- The Energy Partner program delivers measurable load reductions at peak times. Realization rates have been strong for nearly all events. PGE and EnerNOC will continue to seek participants that can deliver similarly reliable impacts in order to develop a reliable and valuable demand response resource.

PGE's recommendation is to continue the pilot through 2016 with modifications to increase market education and focus on DSG customers. With additional time and market awareness, the recruitment efforts should continue to become easier.

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Draft Phase I Report

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Program Evaluation

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April 9, 2015

Table of Contents

List of Figures

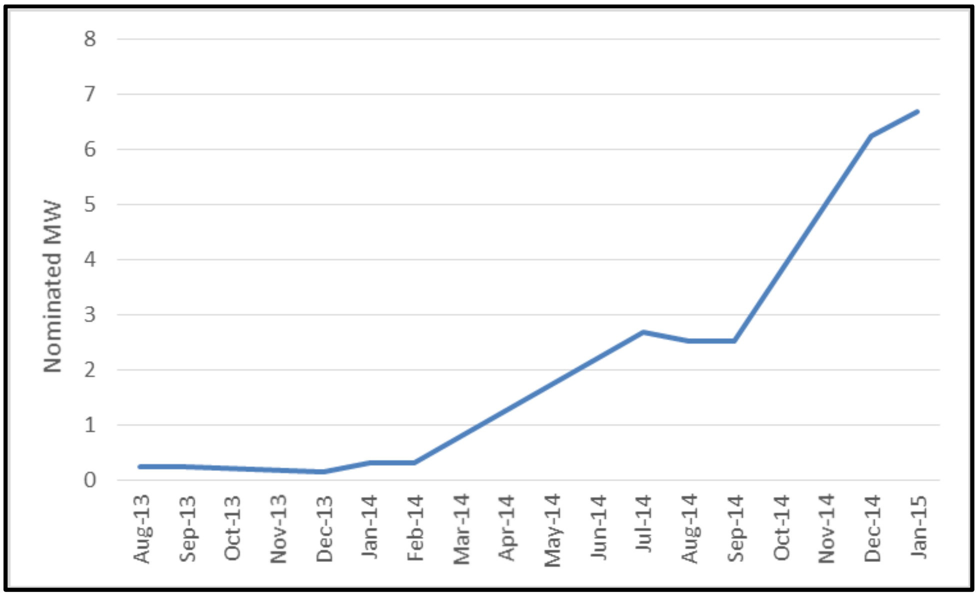
List of Tables

Executive Summary

ES.1 Program Overview

Portland General Electric's (PGE) 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 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 following table illustrates the program's progress in nominating demand up to January 2015.

Figure ES-1: Nominated Load by Month



<u>Status of Outreach Efforts</u>

Customer recruitment efforts have brought the total number of enabled participants to 27 as of the middle of the fourth season, despite a slow ramp-up period in the initial seasons of program implementation. In addition to these customers, EnerNOC reports that discussions have been initiated with 15 customers who are currently in the process of reviewing a proposal. Furthermore, 17 more customers have expressed interest in the program but had yet to pursue a proposal on account of the customer's timeframe and priorities. As for non-participants, there are 139 customers who declined participation or were not pursued for various reasons pertaining to insufficient load, incompatible program hours, having on-site generation, or having direct access service.

Table ES-1: Status of Outreach Efforts, as of Winter 2014-15

Status	Number of Customers	Managed Accounts	Unmanaged Accounts
Enrolled Participants	27	14	13
Reviewing Proposal	15	6	9
Interested in receiving a proposal	17	6	11
Not interested or Disqualified	139	77	62

ES.2 Findings

ES.2.1 Load Impacts: Findings and Recommendations

The following paragraphs summarize the load impacts for the first three seasons of the Energy Partner Program.

Season 1: Summer of 2013

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.

Table ES-2: 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 pm	91º F	2	250	540	216%
8/21/2013	3-6 pm	90º F	2	250	347	139%
9/11/2013	4-7 pm	95º F	2	250	387	155%

Season 2: Winter of 2013-2014

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 event but came up shy of the nominated load for the last two events.

Table ES-3: 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 pm	32º F	2	150	216	144%
12/9/2013	7-9 am	29º F	2	150	338	225%
12/10/2013	6-8 pm	34º F	2	150	316	211%
2/5/2014	4-6 pm	29º F	3	300	283	94%
2/6/2014	4-6 pm	23º F	3	300	262	87%

<u>Season 3: Summer of 2014</u>

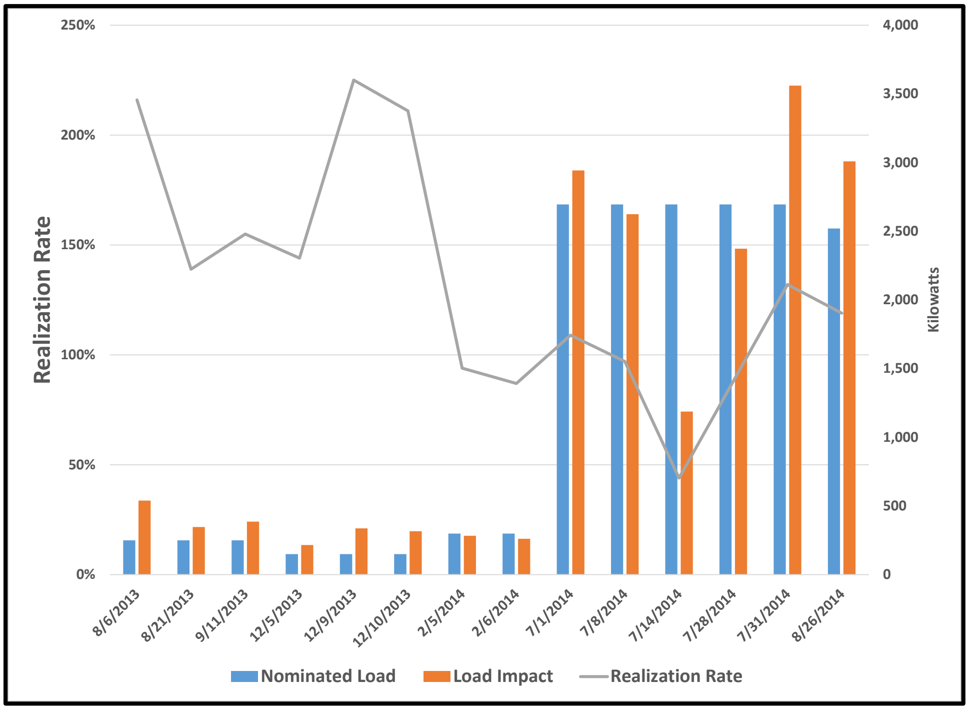
In the second summer season, Season 3, there was a significant increase in the number of program participants and the amount of nominated load. By the second month of this season, 17 customers had enrolled in the Energy Partner Program for a total of 2.52 MW of nominated load shed.

Table ES-4: 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 pm	99º F	13	2,695	2,942	109%
7/8/2014	4-6 pm	88º F	13	2,695	2,624	97%
7/14/2014	3-7 pm	85º F	13	2,695	1,187	44%
7/28/2014	4-6 pm	92º F	13	2,695	2,373	88%
7/31/2014	2-6 pm	91º F	13	2,695	3,560	132%
8/26/2014	4-8 pm	93º F	17	2,520	3,009	119%

The level of realized impacts relative to the nominated load is shown in Figure ES-2 measured in terms of a realization rate (RR, defined as actual load impact divided by nominated load). Nearly two thirds of the events were successful in achieving the nominated load shed.

Figure ES-2: Season 3 Event Realization Rates



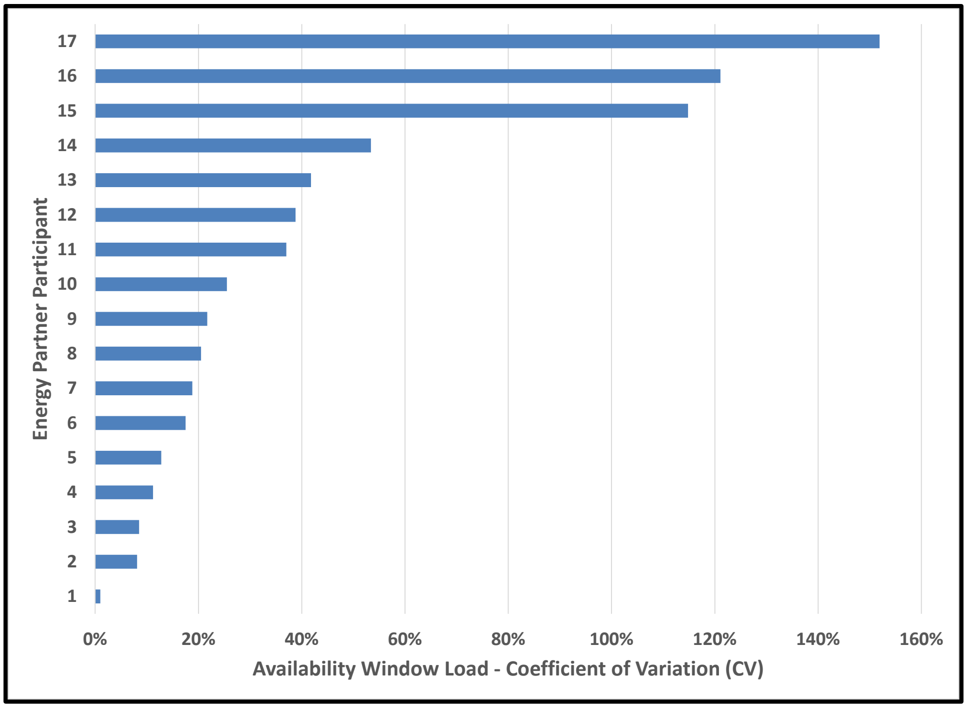
Participant Load Characteristics

The methodology used to calculate program impacts takes the five non-holiday non-event weekdays just prior to an event and averages them to produce a baseline load profile. This baseline is then used to calculate the load impacts by differencing it with the actual load on the event over the event hours. The load characteristics, particularly load variability, of the program participants can have a significant effect on the accuracy of these customer baselines (CBL) and subsequently the accuracy of the estimated load impacts.

To view the load variability for all the customers in a uniform manner, the coefficient of variation (CV) of the 5 minute demands across all the non-event days within the availability window for the Program is effective. The CV is calculated by dividing the standard deviation of the loads in question by their mean. A CV equal to one means that the load varies around the average typically by as much as the value of the mean itself. Less variable loads have a CV less than one and are therefore more predictable.

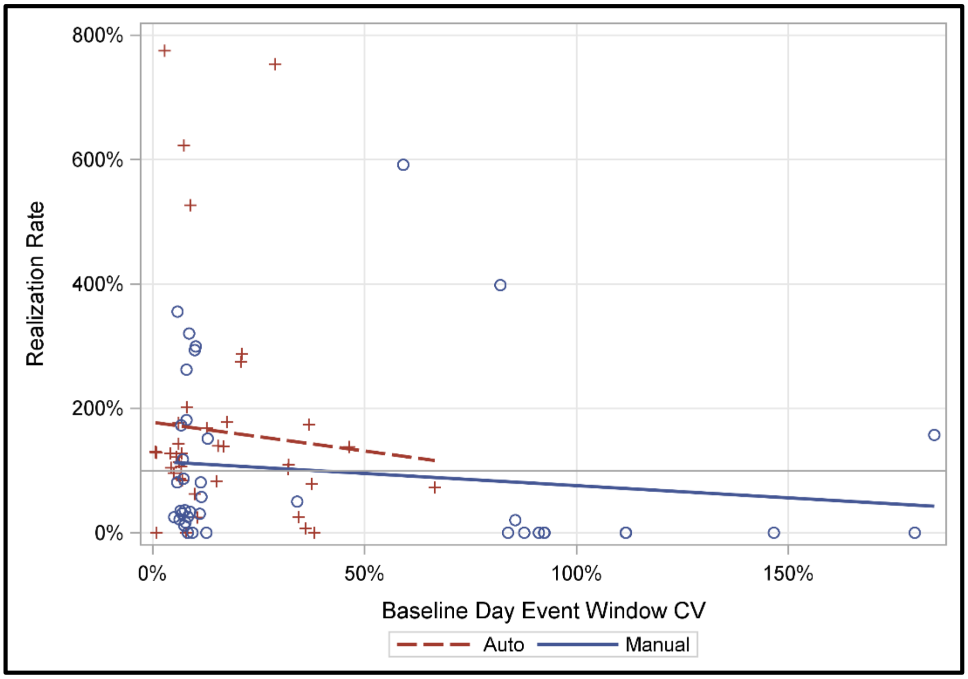
The availability window is defined as 1) non-holiday weekdays from 12 p.m. to 10 p.m. for the summer period and 2) non-holiday weekdays from 6 a.m. to 11 a.m. and 4 p.m. to 9 p.m. for the winter period. In Figure ES-3, each participant's CV for the month of August is presented in declining order. Of the 17 Energy Partner participants in August of 2014, three have a CV greater than 100%. All the remaining participants have a CV less than 60% and of those seven have a CV less than 20%. These results suggest that there may be several customers that are not well suited as participants for the Energy Partner Program as their loads are highly variable. Consequently, calculated baselines would be unreliable indicators of event-day loads if an event were not called.

Figure ES-3: Availability Window Load Variability by Participant



In Figure ES-4, the average RR for each participant is crossed with their CV within the event window during the 2014 summer events. This graph suggests that the load volatility is not a good predictor of load shed performance as measured by the RR. However, this doesn't account for the uncertainty around the estimate of the baselines for which load shed is calculated.

Figure ES-4: Realization Rate versus Load Variability



- **Recommendation:** The screening of prospective participants should include an assessment of the customer's load characteristics, particularly load variability. This will help to minimize any uncertainty of the baseline estimation and subsequently the uncertainty of load impacts associated with the program. An analysis of the baseline uncertainty should be undertaken in the future.

ES.2.2 Implementation: Findings and Recommendations

The following bullets present the summarized findings of the evaluation of implementation efforts. Each finding is associated with a subsection in the report and is paired with an actionable recommendation.

Customer Outreach and Enrollment

- Despite a slow-ramp up period, recruitment efforts have increased participation by enrolling the customers described as "low-hanging fruit" (e.g. water authorities, heavy industry, and cold storage/refrigeration)
  - **Recommendation:** Program staff will continue to pursue the "low-hanging fruit" and once these customer leads have been exhausted, should identify subsequent customer categories with high returns on outreach efforts, such as those in the high-tech sector.
- The greatest barrier to enrollment is the lack of awareness regarding demand response and misinformation (e.g. loss of control over equipment) regarding the nature of participation.

  - **Recommendation:** The program should employ active marketing measures that not only pique customer interest but address customer misconceptions, which are especially prevalent among industrial customers. Program staff should leverage relationships with trusted industry associations (e.g. BOMA, Energy Trust), and customers that participate in demand response programs in other states. Key Customer Managers (KCMs) may assist by leveraging the customer types that are more likely to be informed about demand response (e.g. chains) and also by continuing to educate uninformed customers on the nature of participation.
- The program's marketing message has been refined to transmit a message of providing social benefits while reaping a small financial gain.
  - **Recommendation:** The marketing message should continue to be fine-tuned to address the each customer's individual motivations, which may include environmental sustainability, good public relations, social benefits, low transmission costs, and/or financial benefits.
- The organizational structure at PGE requires that EnerNOC receive approval from KCMs before contacting managed accounts. Program growth has been slower than expected as a result of EnerNOC having restricted access to these managed accounts, who are more likely to be large end-users with the most potential for demand response.
  - **Recommendation:** KCMs should re-engage customers who have already refused to meet with program implementers. In addition, EnerNOC should establish partnerships with industry organizations, as these may provide an avenue to recruiting managed and unmanaged accounts. It should be noted that EnerNOC typically relies on these organizations while promoting the program in other territories, but has done little of this activity while doing so in the PGE territory.

The Decision-Making Process

- Customers are more likely to enroll if they observe successful participation among their peers. Case studies and industry organizations are the primary methods of demonstrating peer participation.
  - **Recommendation:** As stated earlier, program outreach should focus on customers with a predisposition to energy-efficiency by reaching out to customers who are engaged in industry partnerships or energy-efficiency organizations, such as BOMA, or the Energy Trust of Oregon, as these customers are more likely to have a predisposition to energy-efficiency and may even have an energy-efficiency plan in place. EnerNOC should continue to distribute case studies in program outreach efforts.
- The main two reasons for enrollment are the financial gains and social benefits of participation, although these two factors were not weighed equally by participants.

  - **Recommendation:** While the program's main message should continue to promote the social benefits of demand response, the importance of the customer's bottom line should not be underestimated. For those customers who seek the financial benefits of participation, it is important to manage customer expectations of financial benefit, as there have been reports of customers being underwhelmed by the amount of the incentive payment.

- Customers are most apprehensive about incurring costs and losing control of their equipment. There is also some apprehension among undecided customers who prefer to "wait and see" how participation affects their peers.
  - **Recommendation:** Education efforts should focus on the no-cost and optional aspects of participation. The program should address false customer assumptions with case studies that present the experiences of their peers. KCMs may consider asking satisfied participants to discuss the program with their peers who may be observing the program from afar.
- Customers typically take 2-8 weeks to review and sign a proposal. The cost-free aspect of participation helps secure management approval. However, KCMs noted a lack of preparation among EnerNOC's early presentations to customers.
  - **Recommendation:** A proposal timeframe of 2-8 weeks is adequate, but EnerNOC should seek to address the concerns of KCMs who observed a lack of preparation in presentations to customers.

The Commissioning Process

- The typical timeline of the entire commissioning process has been reduced from 23 weeks in 2013 to 12 weeks in 2014.
  - **Recommendation:** EnerNOC should continue to make improvements in the enablement process, especially in the area of equipment installation, where minor delays may cause additional delays later in the commissioning process.
- KCMs and some customers reported that EnerNOC did not provide enough support in developing curtailment plans. KCMs indicated that EnerNOC should offer various options in presenting a curtailment plan to a customer.
  - **Recommendation:** EnerNOC should offer more technical support to present customers with a wider variety of curtailment options.
- Customers continue to report dissatisfaction with the services provided by the third-party installation contractor, and cited the experience as disorganized.
  - **Recommendation:** While the performance of the third-party installation contractor improved in 2014, EnerNOC should continue to encourage this program actor to provide services in a more organized manner.

- A few customers expressed doubts about the accuracy of baseline calculations.
  - **Recommendation:** EnerNOC can ease customer concerns by reviewing baseline calculations with them and making the process more transparent. Any customer inquiries about baselines should be addressed directly with the customer.
- In most cases, curtailment plans have been executed as expected, although in one case a customer reported unresolved issues with how the plan interacts with his equipment; Adjustments to the amount of nominated demand have also been made to accommodate the ability of customers to curtail.
  - **Recommendation:** EnerNOC staff should address the few customers who reported that the curtailment plan is not operating as expected. Additional on-site assistance to these customers may be necessary in some cases.

Participation in Demand Response Events

- Customer experiences met expectations regarding events, and some customers anticipate being able to curtail more load as they become more familiar with the curtailment experience.
  - **Recommendation:** EnerNOC should provide more assistance to customers, especially those who experience growing pains and ask for on-site assistance in identifying more curtailment opportunities. Also, program staff should respond to customer requests for feedback on event participation.
- Participation in events would decline if the program moved to a strict 10-minute notification period.
  - **Recommendation:** The program should not deviate from its current practice of providing advanced notification (i.e. 2-4 hours). Whenever possible, PGE should issue pre-notifications.
- PGE staff expects curtailment to be more difficult for customer during the winter season, but as there have been no winter events for most participants at the time of the interviews, customers had no actual experiences and few notable expectations regarding winter curtailment.
  - **Recommendation:** At least one customer made up the shortfall in nominated demand by finding additional curtailment actions that are only implemented in the winter. If curtailable load proves to be scarcer in the winter, use this example as to work with customers to find additional actions that may be implemented during the winter.

The Value of Real-Time Data

- Customers found the usefulness of real-time data to be limited and expressed a desire for a more comprehensive software product.
  - **Recommendation:** EnerNOC should address the problems with the software product reported by customers, especially in cases where event performance and earnings information was not made available.

Customer Satisfaction

- Five of the customers interviewed were satisfied with the program, four customers were dissatisfied and two customers were undecided. The responses of satisfied customers correlated with low expectation of financial reward, whereas the responses of dissatisfied customers correlated with high expectations of financial reward.
  - **Recommendation:** The payment calculation process should be made more transparent to customers, so they can accurately manage their own expectations of payment. Program staff should express to customers that while the program provides a small financial benefit, it may not be a lucrative activity.
- Customers lacked the information to determine whether participation was a cost-effective activity, therefore some customer were undecided on whether they would continue participation. Customers are unlikely to continue with the program if the financial benefits do not cover the costs of participation. Also, some customers reported dissatisfaction that payment was not disbursed in a timely manner.
  - **Recommendation:** Address the need for timely communication, feedback and information to inform cost-effectiveness.
- One customer has reported dropping out on account of being dissatisfied with the amount of the incentive payment.
  - **Recommendation:** In such cases, customer concerns will not likely be placated by touting the social benefits of participation. This customer serves as an example to manage customer expectations regarding payment.
- Reports of customer satisfaction varied. While some customers were either satisfied or dissatisfied, others said that it was too soon to have an opinion.
  - **Recommendation:** Program staff should follow customer recommendations that satisfaction may be improved by improving installation procedures, and by providing more feedback on curtailment and incentives.

Scalability

- While the Energy Partner program is behind its current goal to provide 9 MW of nominated demand by the end of 2014, the likelihood of meeting the ultimate goal of providing 25 MW by 2017 would be increased by making changes to improve program design and customer awareness. The program has yielded approximately 7 MW of nominated demand to date and this is expected to increase as additional customers are recruited to the program.
    - **Recommendation:** The implementation of program design changes based on early findings will improve the program's progress towards its ultimate goal of 25 MW. The program is a pilot that should continue because it has shown potential to provide additional capacity during times of peak demand.
- The pool of potential participants has been limited by the exclusion of PGE customers who have an Electric Service Supplier (ESS), are enrolled in other PGE DR programs, and the decision to not pursue distributed standby generation customers. This has limited the pool of potential participants that could nominate demand and participate in the program.
    - **Recommendation:** PGE should consider a methodology or change in program design that would accommodate customers that are not currently being pursued (e.g. distributed standby generation customers). Increasing the pool of potential participants would help the program approach its goal of 25 MW of nominated demand by 2017.

1

Introduction

Portland General Electric's (PGE) 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 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"). 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 ten days per month during any summer period or winter period. PGE may not dispatch more than forty 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.

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 2 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 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 report represents the first of two evaluation reports to be developed over the pilot period. This report covers the program's first three seasons.

2

Methods

2.1 Impact Analysis

The Phase I 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 return the observed event day shape, the baseline shape, and the load impact shape for each individual participant following each event.
- B. 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 very good estimates, 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. Alternative evaluation methods should be considered in the future, however, to confirm this assessment.
- C. Along with the individual site event load impact calculations, the 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. The 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. There have been a number of research studies in the past decade that have examined these customer baseline (CBL) methodologies. The most prominent have been KEMA 2003,[1] Quantum 2004,[2] Quantum 2006,[3] LBNL 2008[4], and KEMA 2011.[5]

[1] 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.

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 5 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 very minor differences from that used in the LBNL study. These differences include: 1) using a morning adjustment based on the average of the three-hour period ending three hours prior to the start of the event period instead of the average of the two hours immediately prior to the start of the event, and 2) the adjustment factor 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 very difficult. The second difference has been found in other studies to be of no real 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 will be used to estimate the load impacts for each individual participant in the program in this Phase I report. Itron does recommend that sometime during the evaluation a regression based approach be implemented to confirm the accuracy of the Energy Partner CBL.

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2 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.

3 *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.

4 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

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

2.2 In-Depth Interviews

In the second and fourth seasons, the evaluation team conducted discussions with program actors to characterize the key issues pertaining to the PGE Energy Partner Program. These discussions aimed to monitor the status of program activities and to characterize customer experiences with the program. The evaluation team conducted interviews based with EnerNOC staff, new participants, continuing participants, and two types of PGE staff - program staff and key customer managers (KCMs). These discussions were based on interview guides (see appendix) that were developed with input from PGE and are described in more detail in the following paragraphs. The following table presents an overview of the discussions held with program actors.

Table 2-1: Overview of Interviews with Program Actors

Program Actor	Round One (Season Two)	Round Two (Season Four)
EnerNOC Staff	1	1
New Participants	3	8
Continuing Participants	Not Applicable	3
PGE Staff	1	1
PGE KCMs	0	2

2.2.1 Discussions with Program Implementer (EnerNOC)

On two occasions, the evaluation team conducted in-depth interviews with the EnerNOC staff to characterize the implementer's perspective regarding the program's rollout and development. The first interview was conducted with three EnerNOC staff members, including two program managers and an account managers. The second interview was conducted with one of the program managers. These discussions identified new issues and revisited topics that were raised in the first discussion.

2.2.2 Discussions with Program Participants (New and Continuing)

During the course of these interviews, new and continuing customers were asked to characterize their experiences with the decision to enroll, the enablement process, curtailment events, notification, the payment process, and other aspects of program participation. Two types of participants (new participants and continuing participants) were interviewed during the course of the evaluation to track how their views about the program changed during the course of the program's development. The three *new* participants that were interviewed in the second season were also interviewed in the fourth season as *continuing* participants. An additional eight new participants were interviewed during the fourth season. In general, participants were either managed accounts or general business accounts and operated various types of facilities, such as water authorities, food processing, lumber manufacturing, hotel services, and manufacturing. The majority of these customers operated some form of manual, rather than automated, curtailment strategy.

2.2.3 Discussions with PGE Program Staff

On two occasions, the evaluation team conducted in-depth interviews with PGE program staff member to identify PGE's views about the program's status and to monitor program implementation efforts. After the first interview was conducted with three PGE staff members (program evaluation, program manager, and marketing) a staff change occurred which resulted in one recently hired staff member be interviewed for the second interview (product development). These discussions identified new issues and revisited topics that were raised in earlier discussions.

2.2.4 Discussions with PGE Key Customer Managers

A second type of PGE staff member was also interviewed –key customer managers (KCMs). These staff members serve as the intermediaries between PGE and the Energy Partner program implementer, EnerNOC. KCMs are involved in the recruitment of managed accounts and initiate program discussions with customers before referring them to EnerNOC. Interviews with KCMs were only conducted as part of the second round of interviews in season four, as interviews with these program actors were not part of the original evaluation plan. It was later decided to interview these program actors, because KCMs provide a unique perspective on customer recruitment to the program since they are the ones who initially introduce the program to their customers.

3

Load Analysis

3.1 Summary of Event Impacts

This report discusses the Energy Partner event impacts for Season 1 through Season 3. Seasons 1 and 3 were summer seasons and Season 2 was a winter season.

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 pm	91º F	2	250	540	216%
8/21/2013	3-6 pm	90º F	2	250	347	139%
9/11/2013	4-7 pm	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

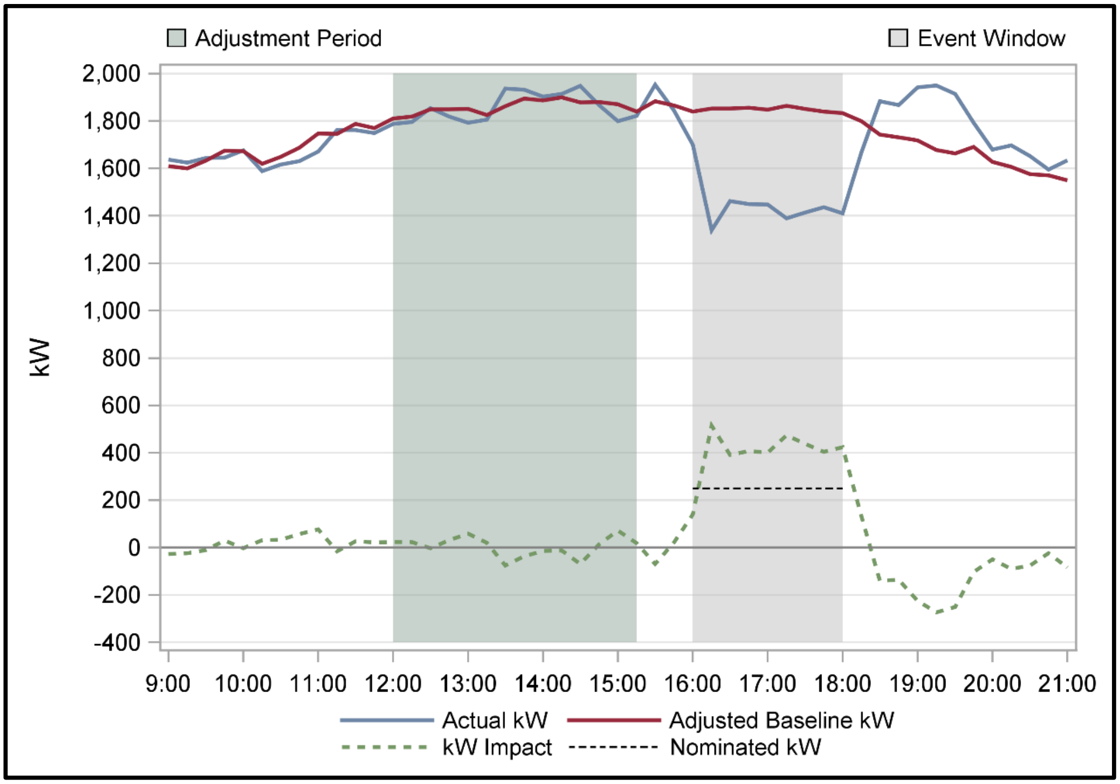


Figure 3-2: August 21, 2013 Aggregate Event Impact

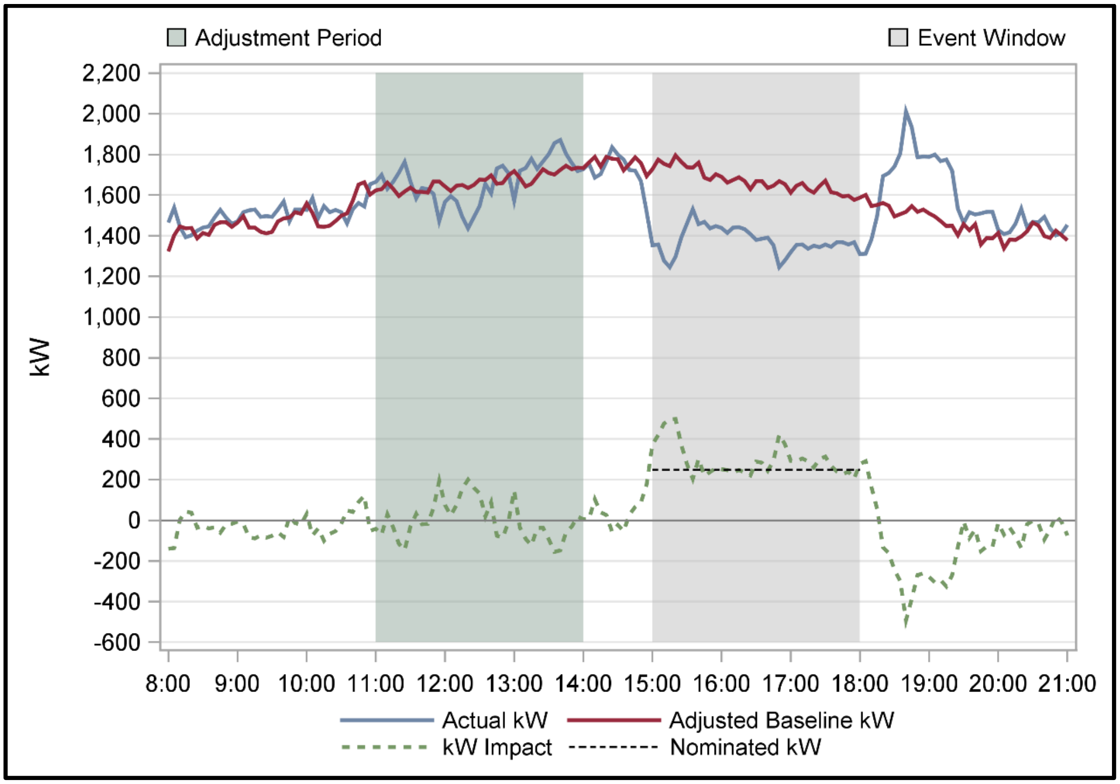
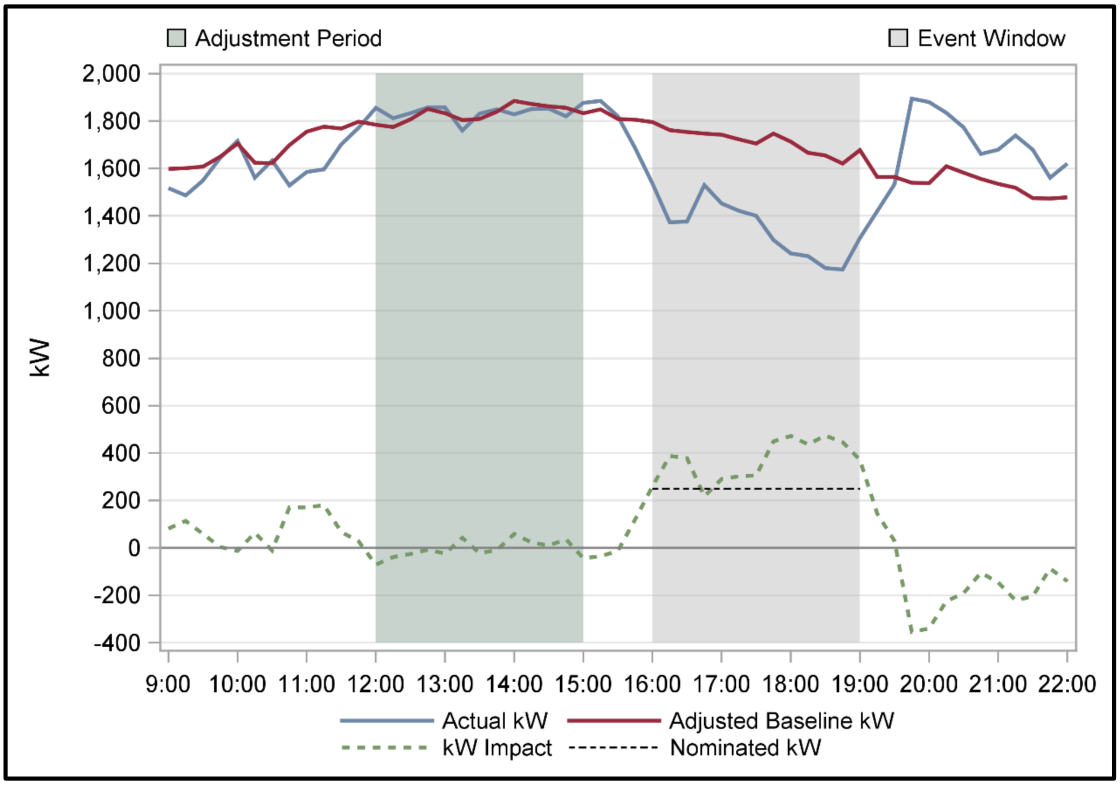


Figure 3-3: September 11, 2013 Aggregate Event Impact



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 of the events were 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 9th event was called for the morning whereas the December 10th 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 not able to contribute virtually at all 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 pm	32º F	2	150	216	144%
12/9/2013	7-9 am	29º F	2	150	338	225%
12/10/2013	6-8 pm	34º F	2	150	316	211%
2/5/2014	4-6 pm	29º F	3	300	283	94%
2/6/2014	4-6 pm	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

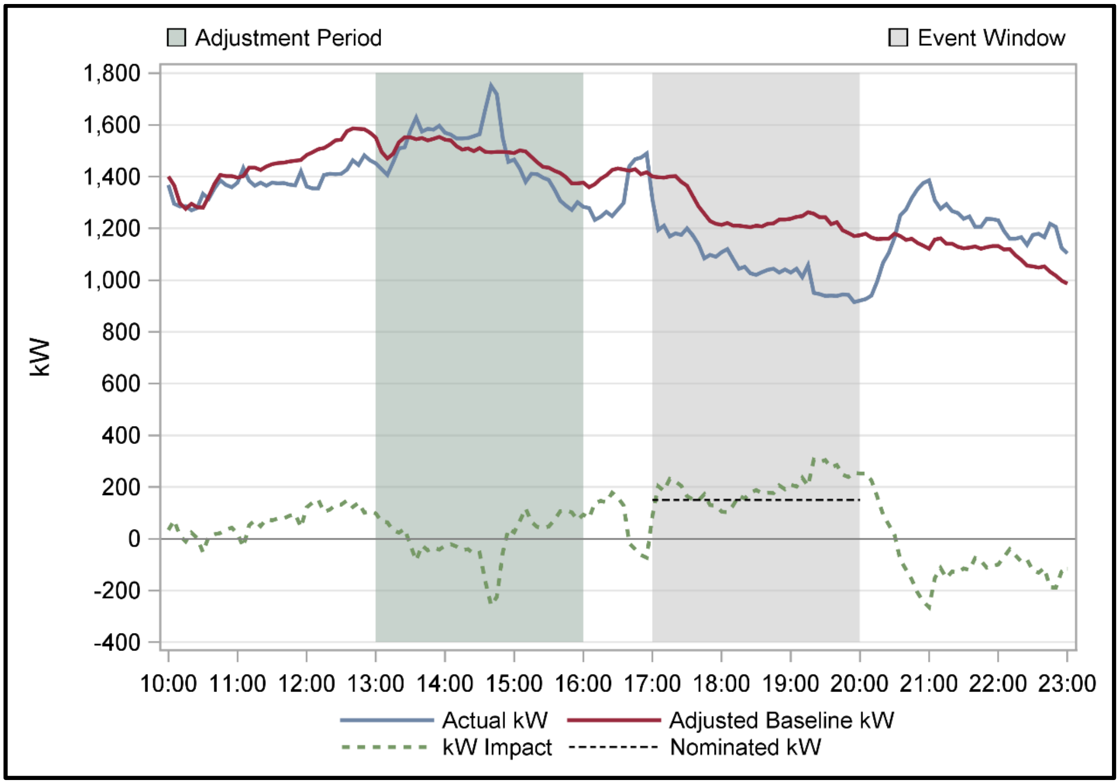


Figure 3-5: December 9, 2013 Aggregate Event Impact

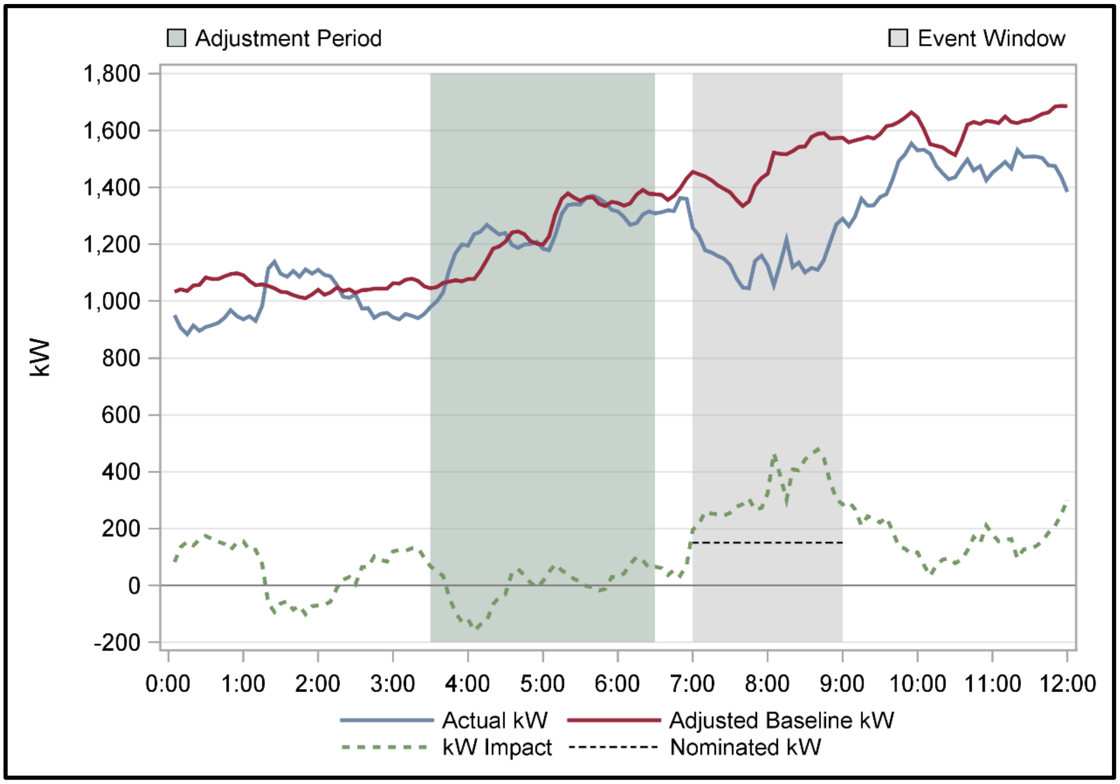


Figure 3-6: December 10, 2013 Aggregate Event Impact

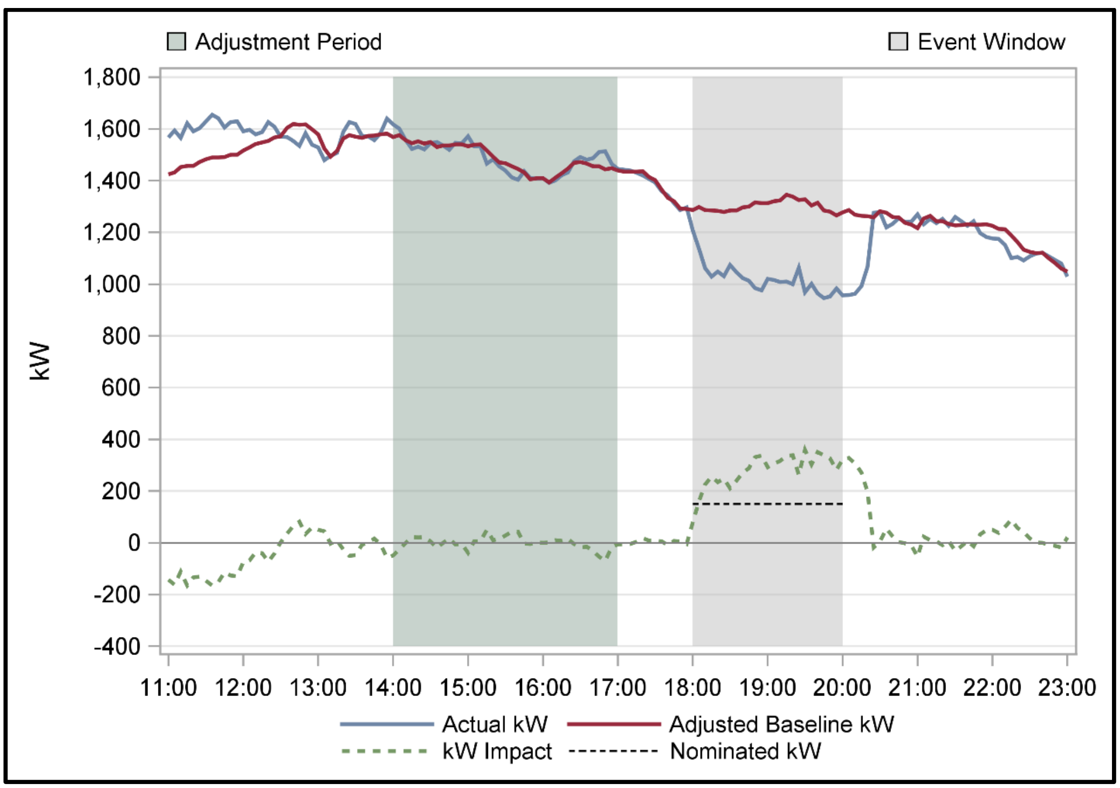


Figure 3-7: February 5, 2014 Aggregate Event Impact

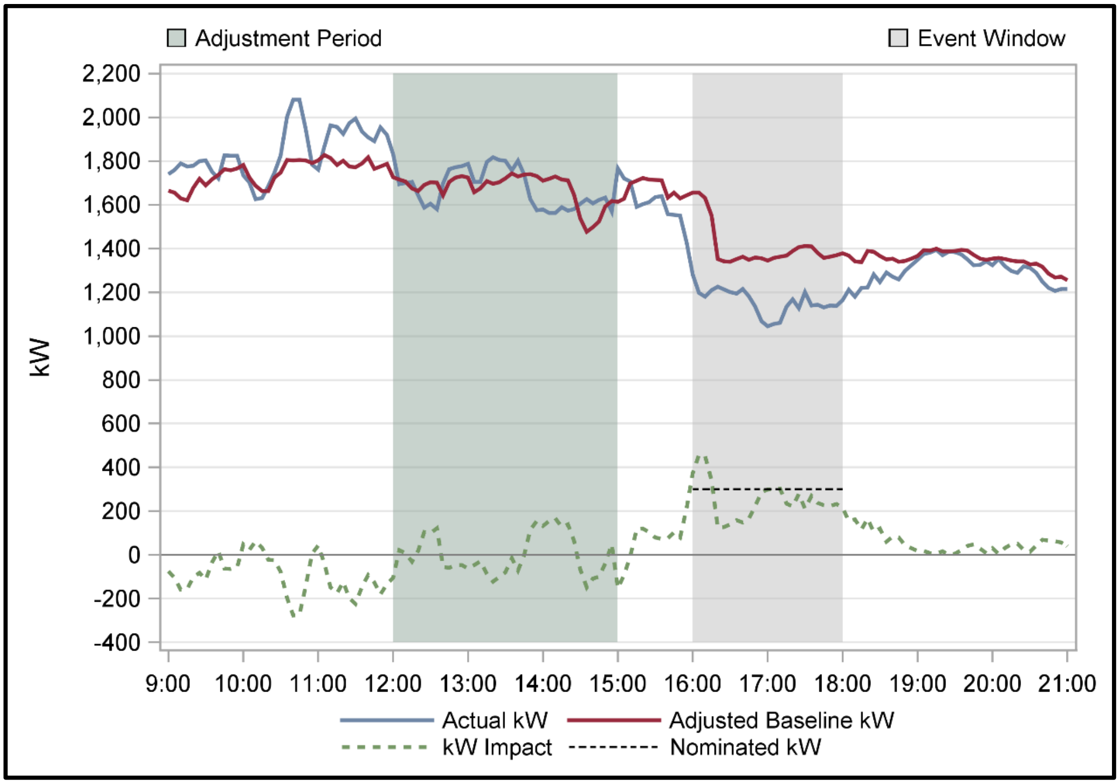
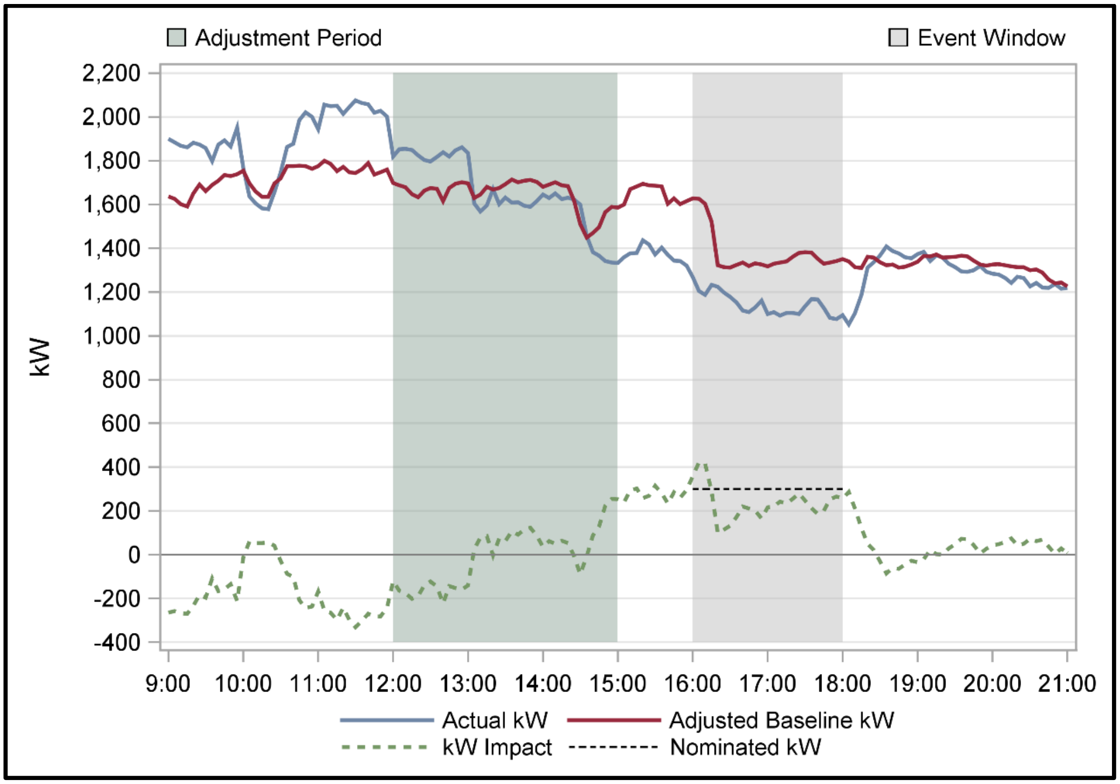


Figure 3-8: February 6, 2014 Aggregate Event Impact



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 the events 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 participant's 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 for 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 information 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 pm	99º F	13	2,695	2,942	109%
7/8/2014	4-6 pm	88º F	13	2,695	2,624	97%
7/14/2014	3-7 pm	85º F	13	2,695	1,187	44%
7/28/2014	4-6 pm	92º F	13	2,695	2,373	88%
7/31/2014	2-6 pm	91º F	13	2,695	3,560	132%
8/26/2014	4-8 pm	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 14th event had 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 14th event failed to meet expectations is that two water authorities, who represent a large amount of nominated load, could not curtail, likely due to minimum water level requirements.

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

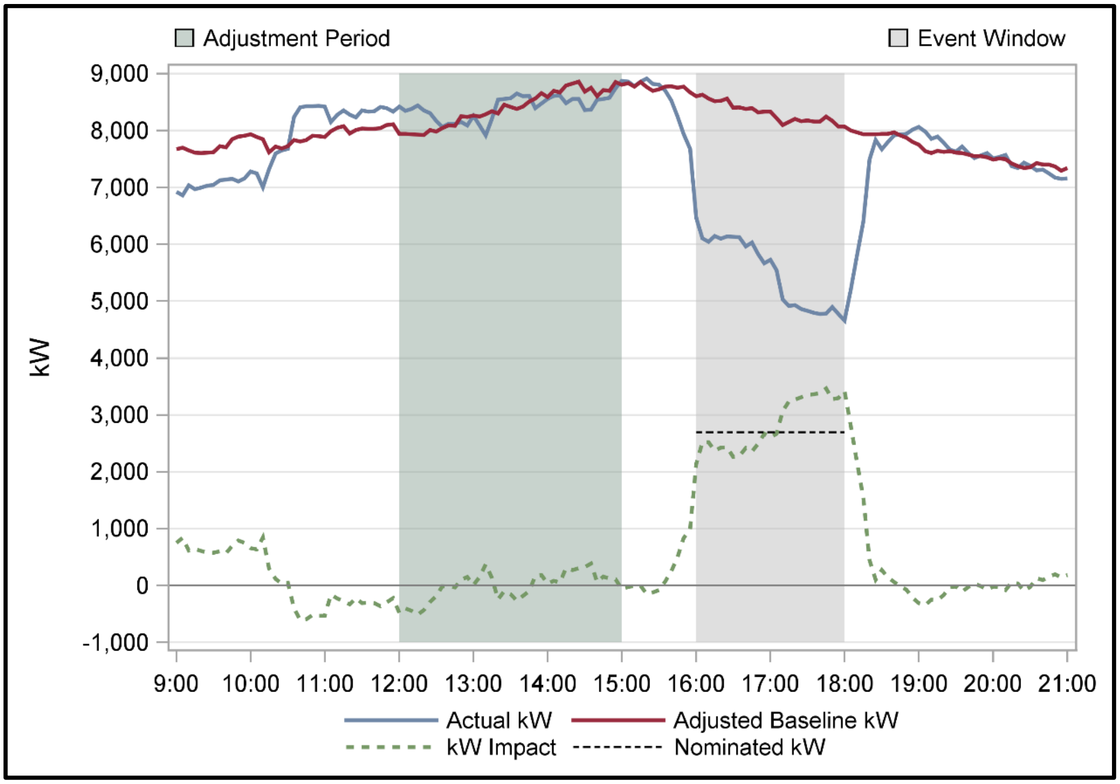


Figure 3-10: July 8, 2014 Aggregate Event Impact

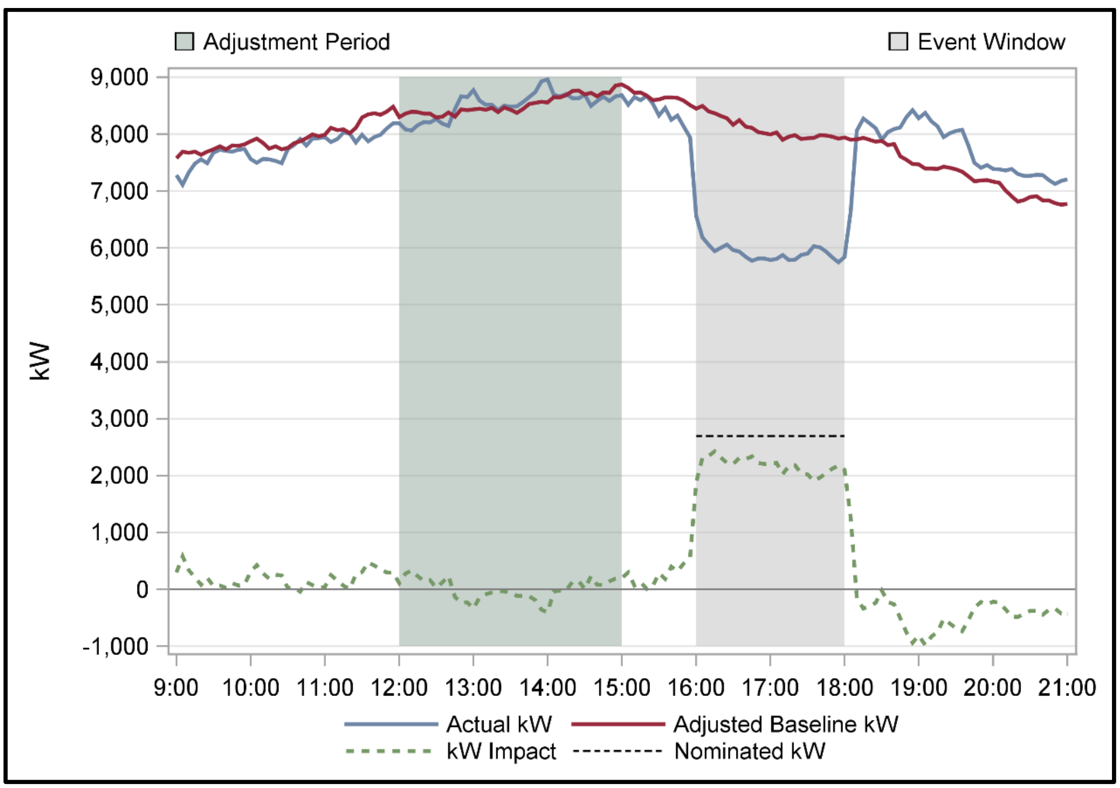


Figure 3-11: July 14, 2014 Aggregate Event Impact

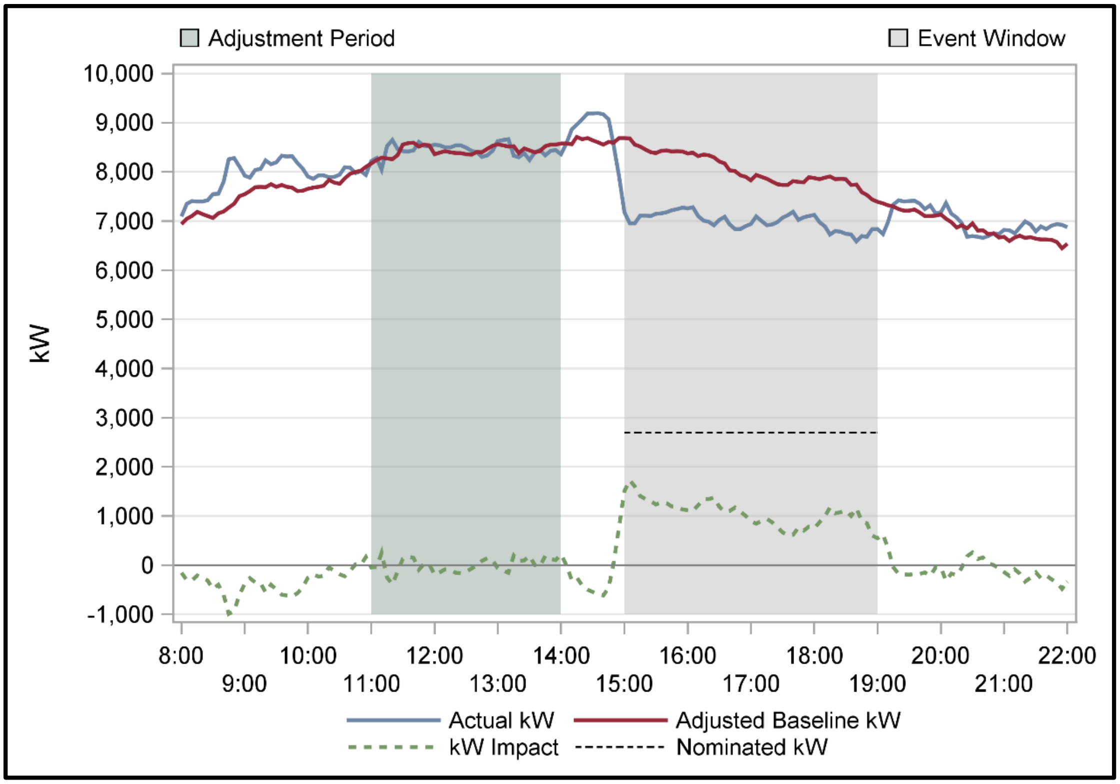


Figure 3-12: July 28, 2014 Aggregate Event Impact

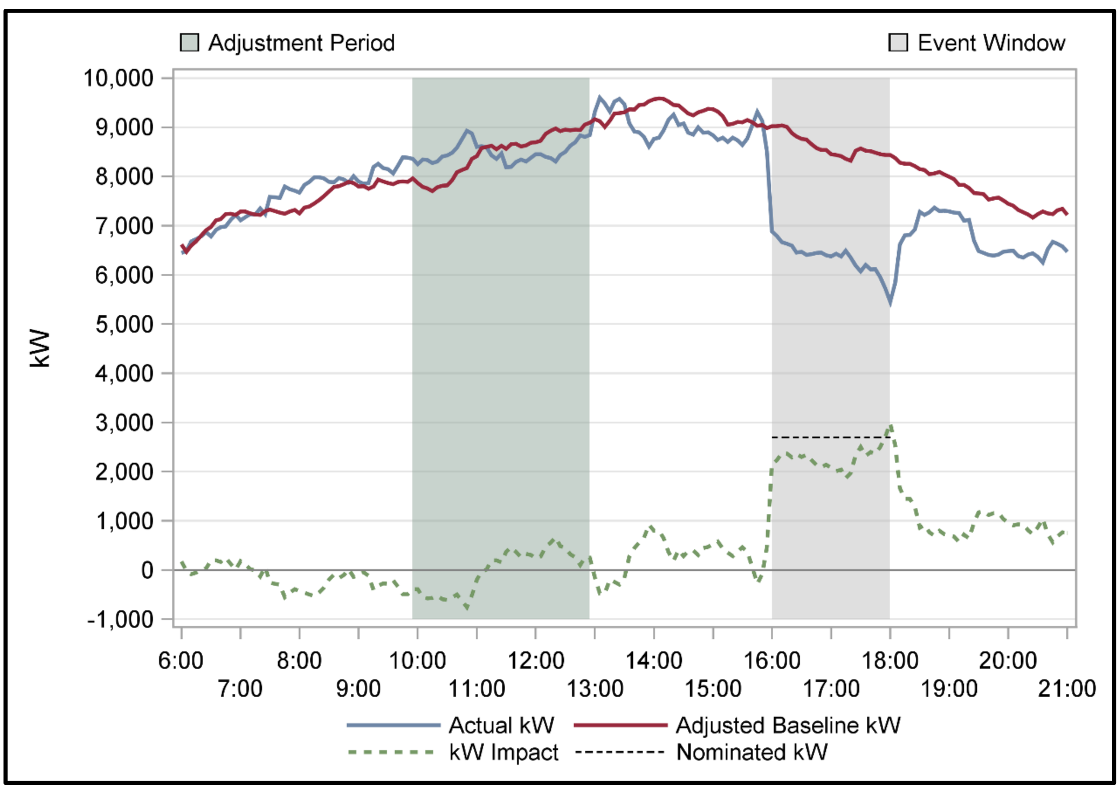


Figure 3-13: July 31, 2014 Aggregate Event Impact

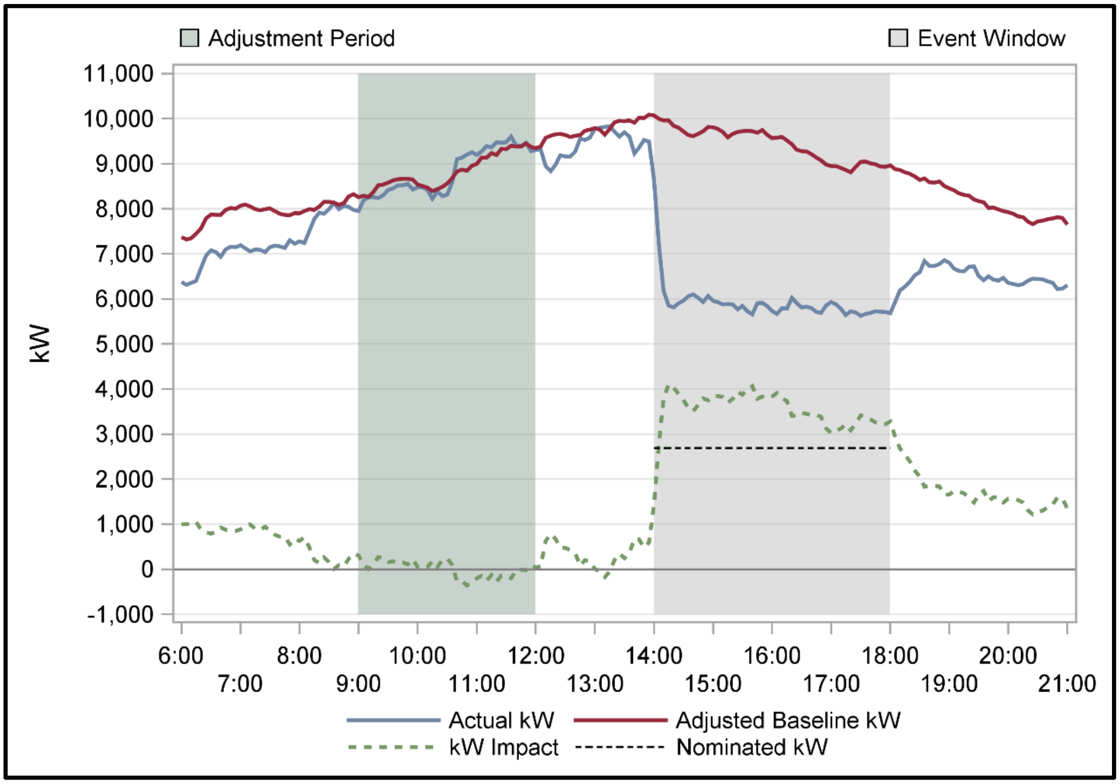
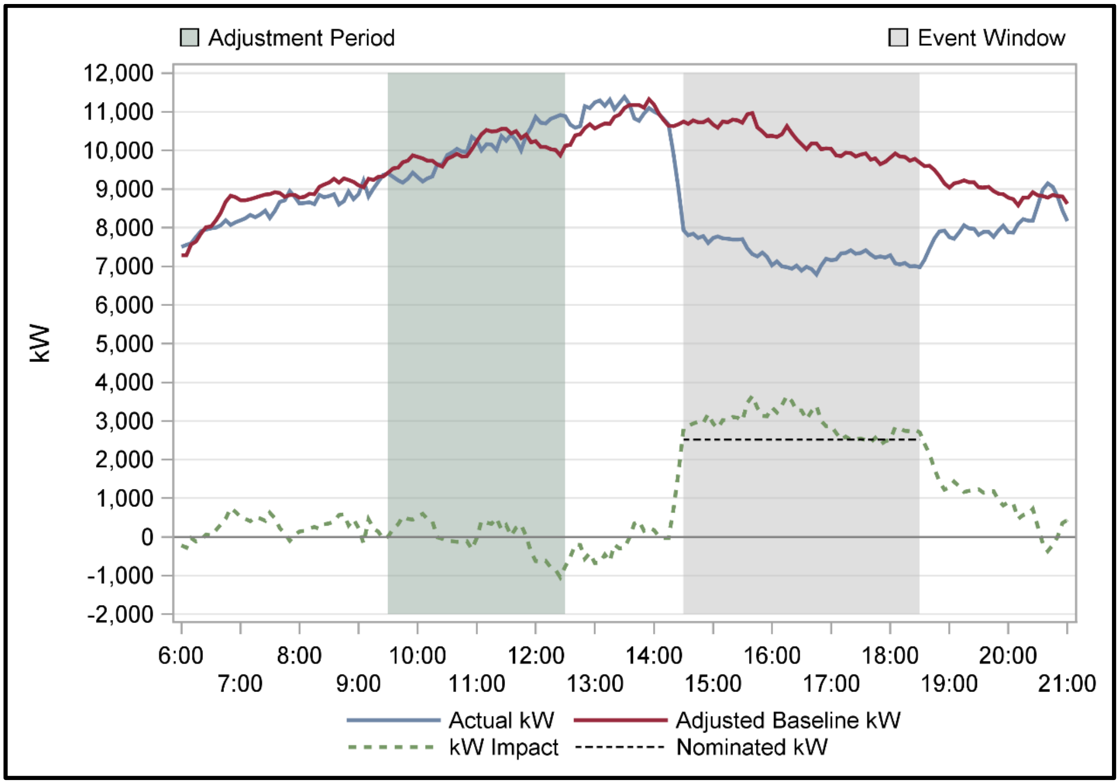


Figure 3-14: August 26, 2014 Aggregate Event Impact



3.2 Current Participants' Load Characteristics

The customers who are participating in the Energy Partner program as of Season 3 vary significantly in their load characteristics. This section looks at several load characteristics of the program participants and discusses some of the implications of these characteristics with respect to the program's performance.

3.2.1 Size and Nominated Load Distributions

Figure 3-15 is a scatter plot of the August 2014 participants' maximum non-coincident peak (NCP) 5 minute loads are highly correlated to the maximum 5 minute load in the event window. This suggests that for the most part, these customers have significant load during the event period and should be able to shed some load within the event window.

Figure 3-15: NCP versus Maximum Event Window Demand

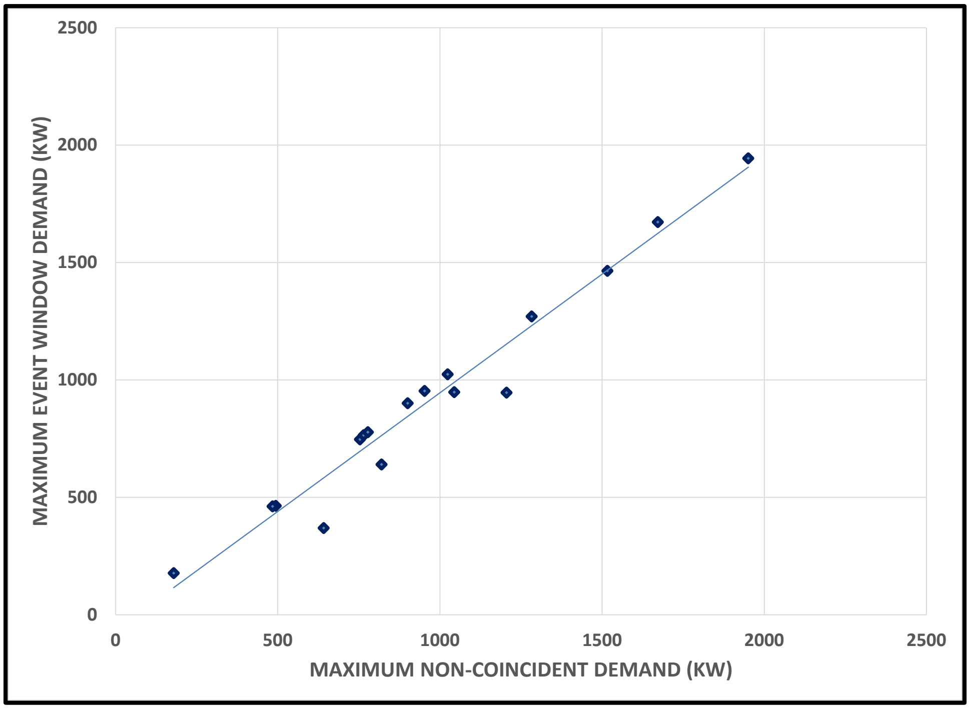


Figure 3-16 shows a scatter plot of the August 2014 event window NCP versus the event window load factor for all of the participants. The load factor is the ratio of the peak 5 minute demand within all event window hours for the month over the average 5 minute demand within all event window hours for the month. The load factor is a measure of how much the load peaks within the event window. The higher the load factor the closer the peak and the average 5 minute demand. A low load factor indicates that the loads spike more. A low load factor may also be an indicator that the customer may not be well suited for the program.

Figure 3-16: Event Window NCP versus Event Window Load Factor

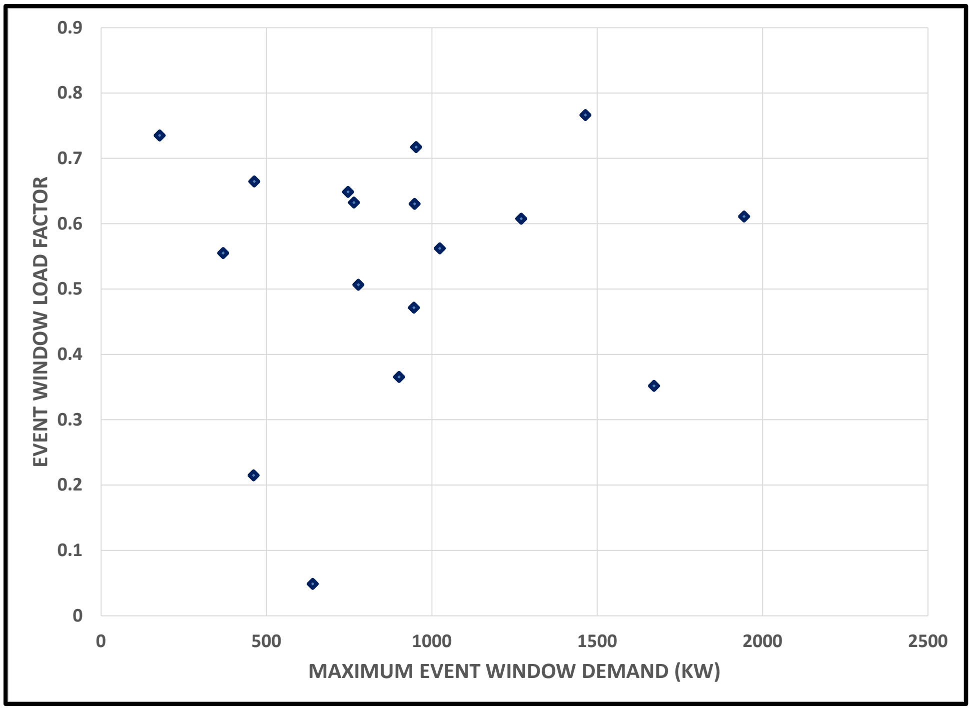


Figure 3-17 shows a scatter plot of the participants' nominated load versus their event window NCP. This shows that the participants' nominated load is never greater than their event window NCP. This picture also shows that on average the nominated load represent about one quarter of their peak load within the event window. To further demonstrate this, a simple linear regression line with zero intercept has been drawn through the data. The resulting equation shows that the average nominated demand is 26% of the maximum event window peak demand for the participants. On an individual basis there is considerable variation around the average.

Figure 3-17: Event Window NCP versus Nominated Load

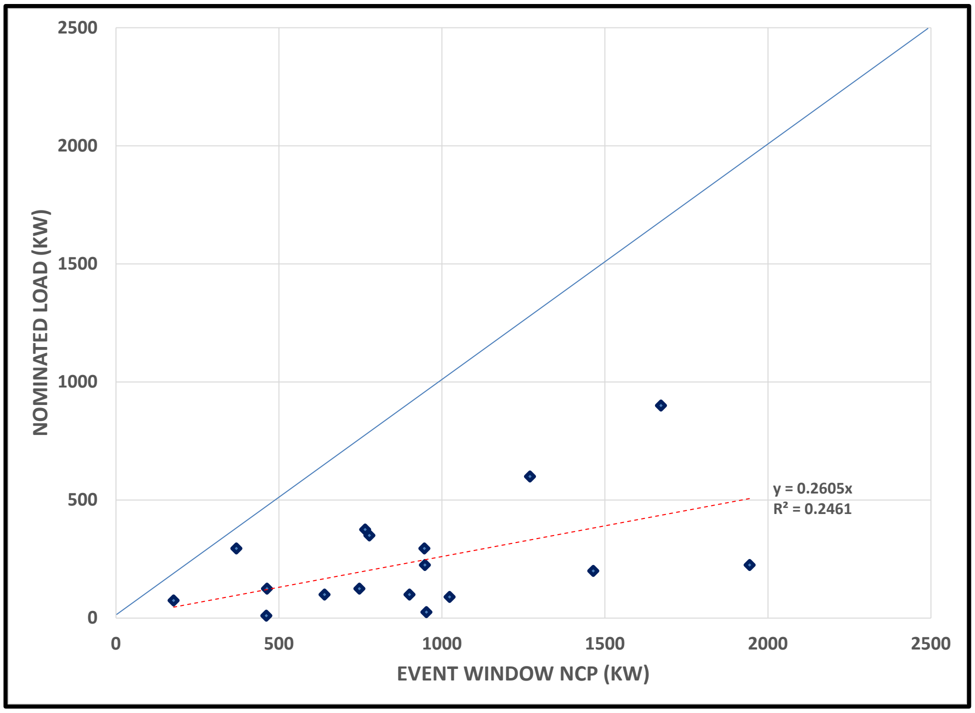
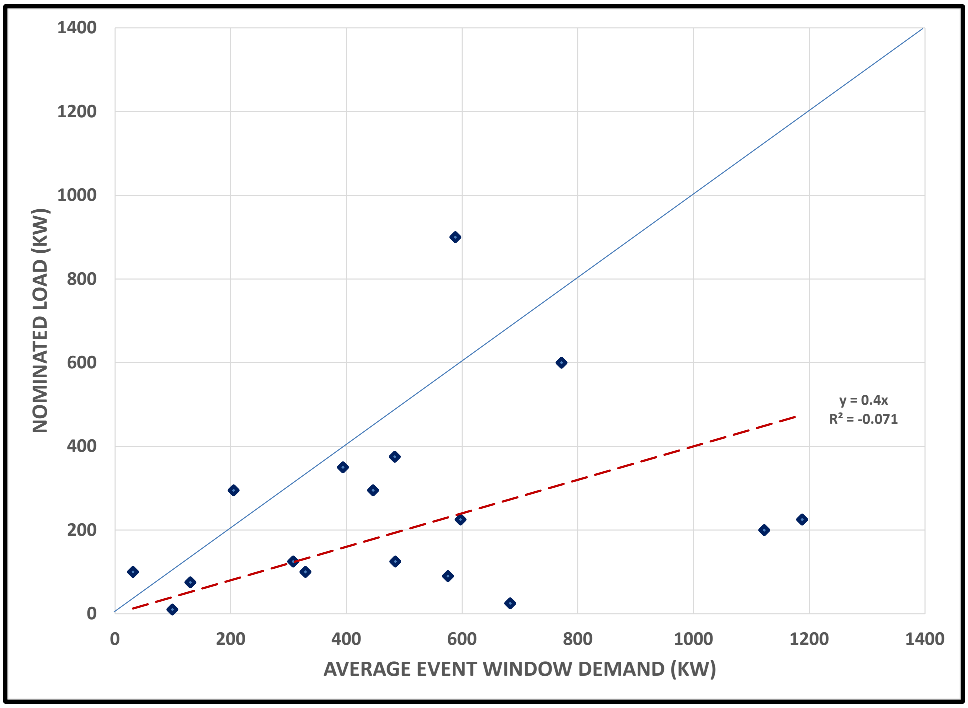


Figure 3-18 is a scatter plot of the average 5 minute demands across all hours in the event window for the month of August 2014. This graph, on the other hand, shows that there are several participants with an average event window load less than their nominated load. These are the participants above the diagonal line. This suggests that these customers' nominated load should be revisited as they will likely not be able to meet their nominated load shed target. To further illustrate this, a simple linear regression line (red dashed) with zero intercept has been drawn through the data. The resulting equation shows that the average nominated demand is 40% of the average event window demand for the participants. However, on an individual basis there is considerable variation around the average and there is not a good correlation here either.

Figure 3-18: Average Event Window Demand versus Nominated Load



3.2.2 Load Variability versus Baseline Stability

The variability of the loads within the event window across the weekdays of a season have implications on how good the calculated baselines will be at representing the load in the absence of an Energy Partner event. Figure 3-19 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 CV for the event window across the season is 8%. Figure 3-20 shows the load profiles for the days which contributed to the baseline load profile. As you can see there is some variability about the unadjusted baseline, but in general, the contributing days are very similar to the resulting baseline.

Figure 3-19: Customer A: July 31, 2014 Baseline, Actual, and Difference

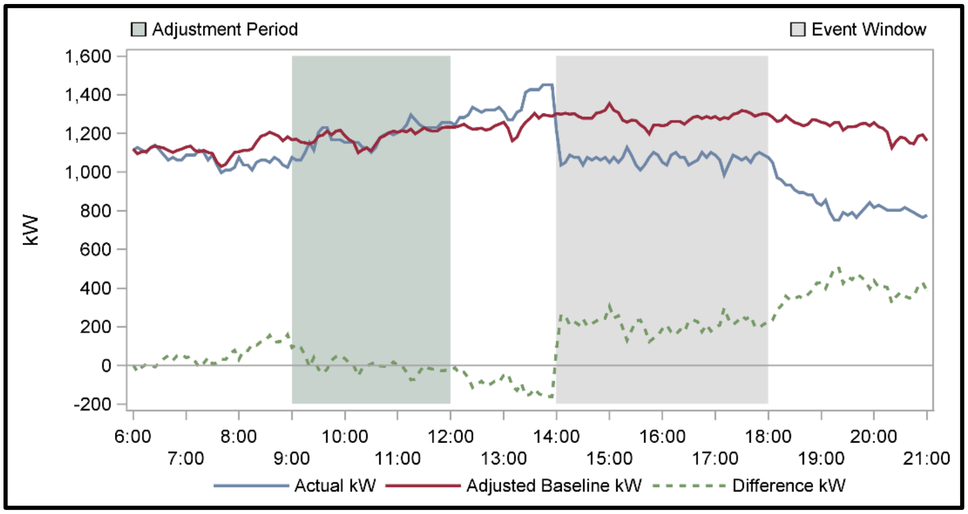


Figure 3-20: Customer A: July 31st Baseline and Contributor Load Profiles

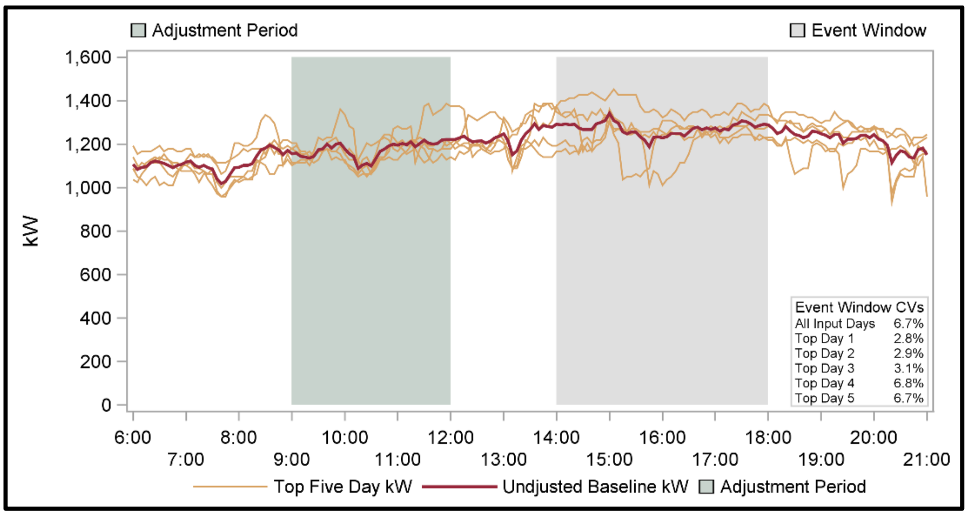


Figure 3-21 shows the adjusted baseline, the actual load and the load impact for another participant (Customer B). As you can see in this case, the load is volatile but it does have a pattern to it which the adjusted baseline has capture to some extent. Figure 3-22 shows the load profiles that contributed to this participant's baseline. As you can see, 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 they appear not to operate at a significant level for much of the time during the event window.

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

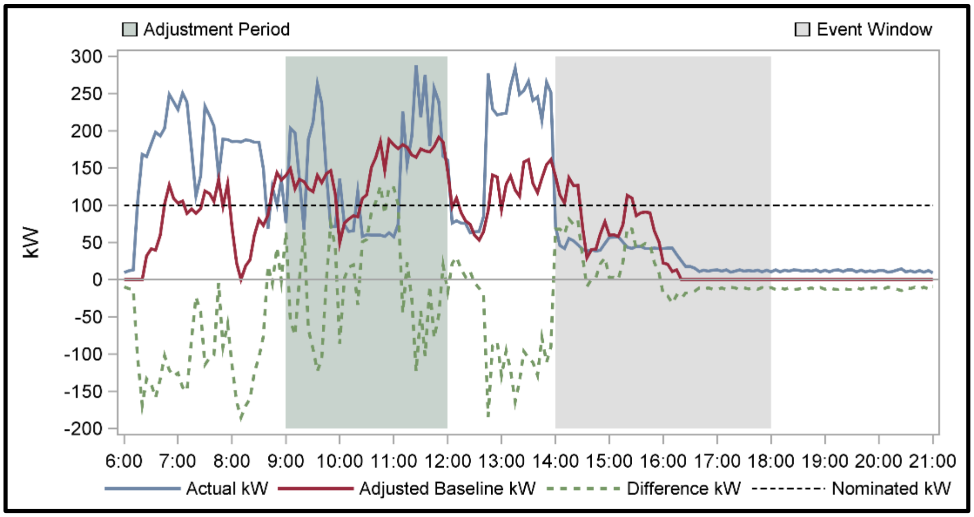
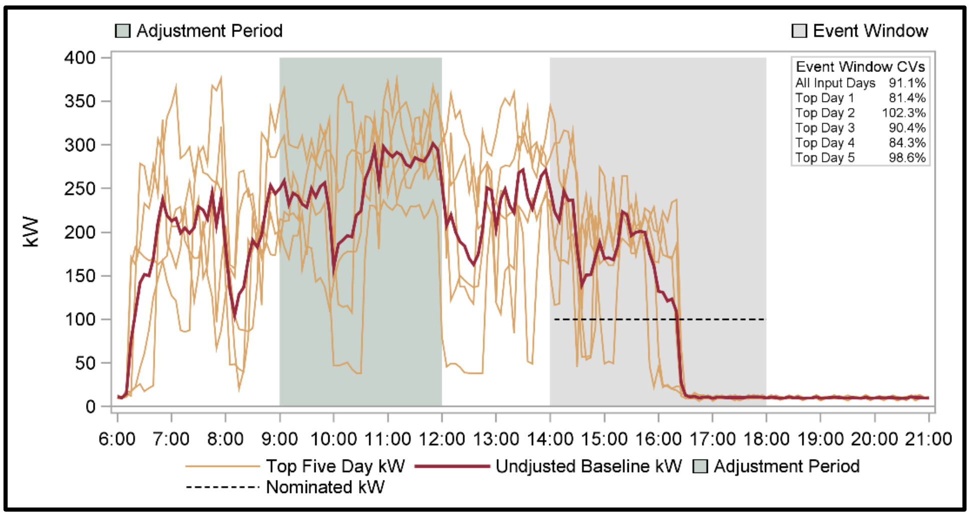


Figure 3-22: Customer B: July 31st Baseline and Contributor Load Profiles



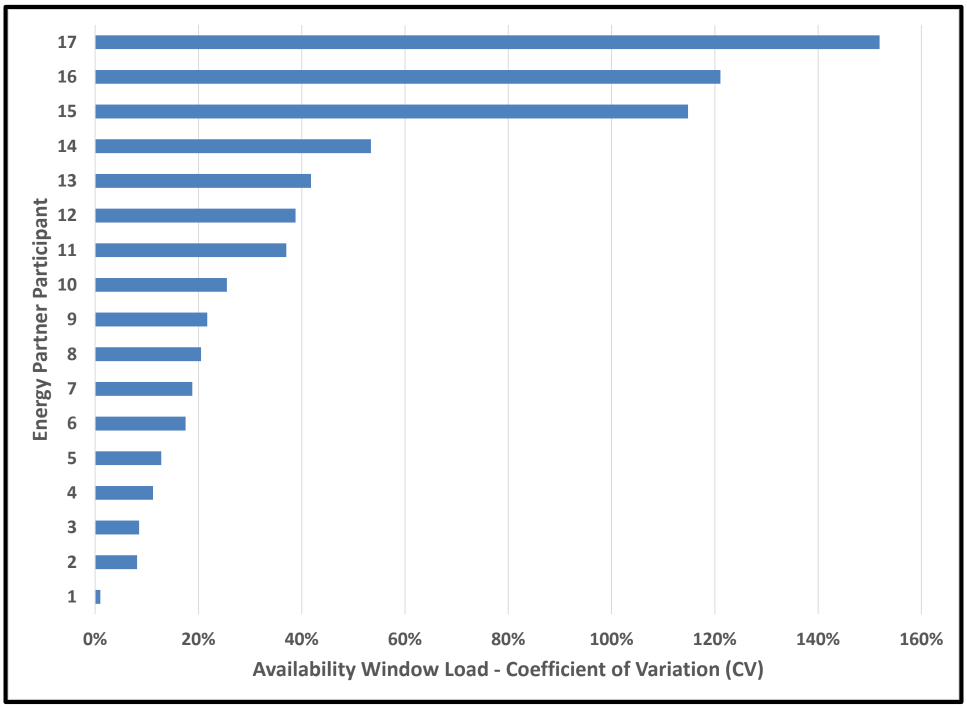
To view the variability of the loads for all the customers in a uniform manner, it is possible to calculate the coefficient of variation of the 5 minute demands across all the non-event days within the availability window for the Program. The CV is calculated by dividing the standard deviation of the loads in question by their mean. A CV equal to one means that the load varies around the average typically by as much as the value of the mean itself. Less variable loads have a CV less than one and are therefore more predictable.

The availability window is defined as 1) non-holiday weekdays from 12 p.m. to 10 p.m. for the summer period and 2) non-holiday weekdays from 6 a.m. to 11 a.m. and 4 p.m. to 9 p.m. for the winter period. Customer A's CV across the availability window was 8% whereas Customer B's CV was 152%.

In Figure 3-23, each participant's CV for the month of August is presented in declining order. Of the 17 Energy Partner participants in August of 2014, three have a CV greater than 100%. All the remaining participants have a CV less than 60% and of those seven have a CV less than 20%. These results suggest that there may be several customers that are not well suited as participants for the Energy Partner Program. What is meant by this is that their loads are highly variable making the calculated baselines unreliable as an indication of what the loads would be on an event day if an event was not called. It is difficult to say with any certainty what their load would have been had an event not be called. For example, for Customer B, their true baseline could have more than double or less than half of what was calculated and therefore the true impact could have well exceeded the nominated load or it could have fallen very short of it. As a very basic rule of thumb, the event window load CV should always be less than 100% and preferably much less than that.

From an operational perspective, the highly volatile load customers might be better suited for a firm service level type of DR program where they are asked to ensure that their load does not exceed a specific level during events rather than a pay for performance type program like Energy Partners.

Figure 3-23: Availability Window Load Variation by Participant

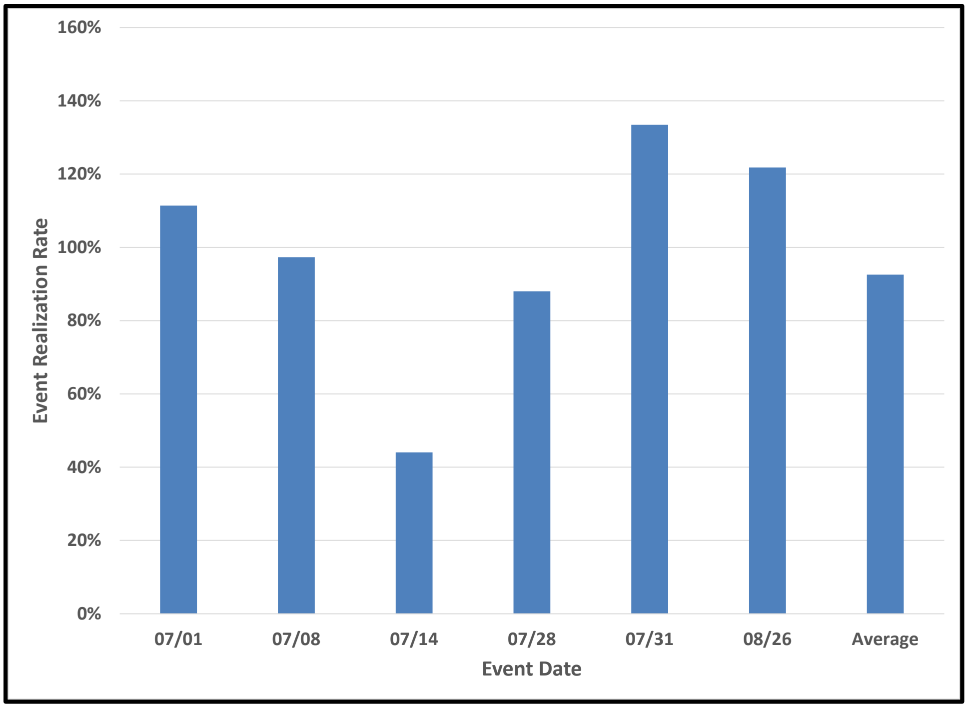


3.3 Impact Reliability

Overall, event level performance can be examined by looking at how well the portfolio of participants did in aggregate relative to the overall nominated load. Figure 3-24 shows the overall event specific realization rates for each of the Season 3 events as well as the overall season average.

For most of the events the program shed close to or above 100% of the nominated load. There was one event were the program did not perform well. This particular event was the third event during the season. In general, as the program adds more customers there should be less variation in the cross event performance. One participants low performance will likely be cancelled out by another's high performance, provided there aren't a small number of customers with exceedingly high nominated loads relative the majority of the participants.

Figure 3-24: Season 3 Event Realization Rates



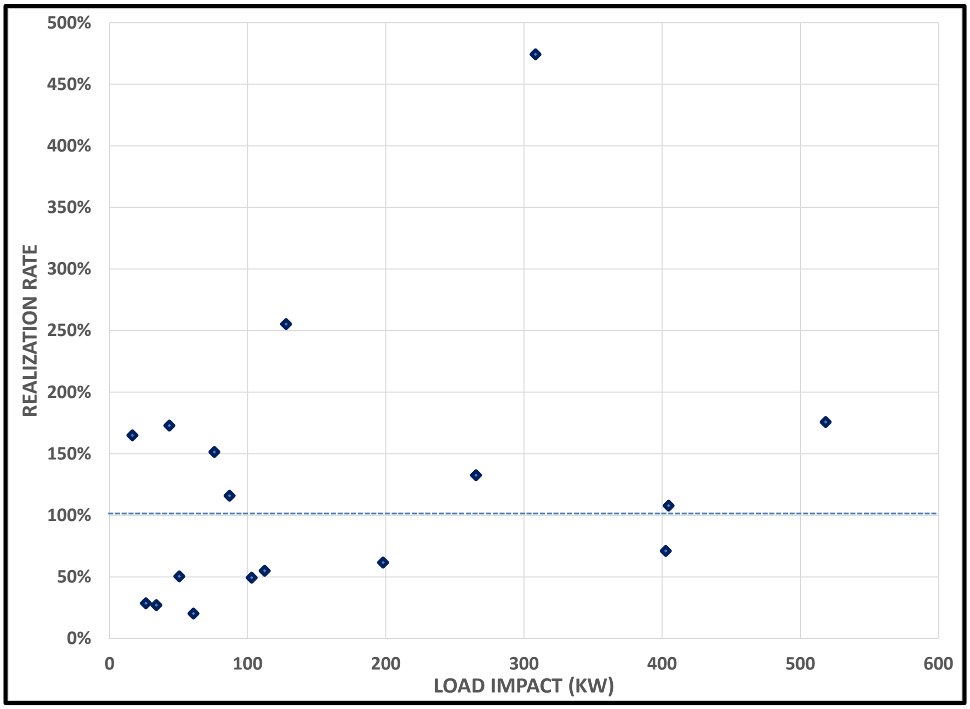
To get an indication of the individual participants' performance, we need to dive down a little deeper. If we assume that the baselines are a good indication of the load in the absence of an event, which Itron believes they are in the majority of cases, we can assess the performance of the participants by examining their estimated load drop relative to their nominated loads. To assess individual participant performance, we will examine the realization rate of each customer for the events during season 3 as there were numerous events and there was the largest level of program participation.

3.3.1 Participant Variance in Realization Rate

The realization rate is calculated by dividing the average event load drop by the nominated load. Those with a realization rate equal to or greater than one performed at or better than their nominated load. Those with a realization rate less than one didn't not perform to expectation.

Figure 3-25 shows a scatter plot of the average load drop impact for all of the events in the summer of 2014 (Season 3) versus their associated Realization Rate (RR). A little more than half of the participants had a realization rate greater than 100%, which helped compensate for those customers who underperformed. The setting of a customer's nominated load should be less conservative in some cases and more conservative in others.

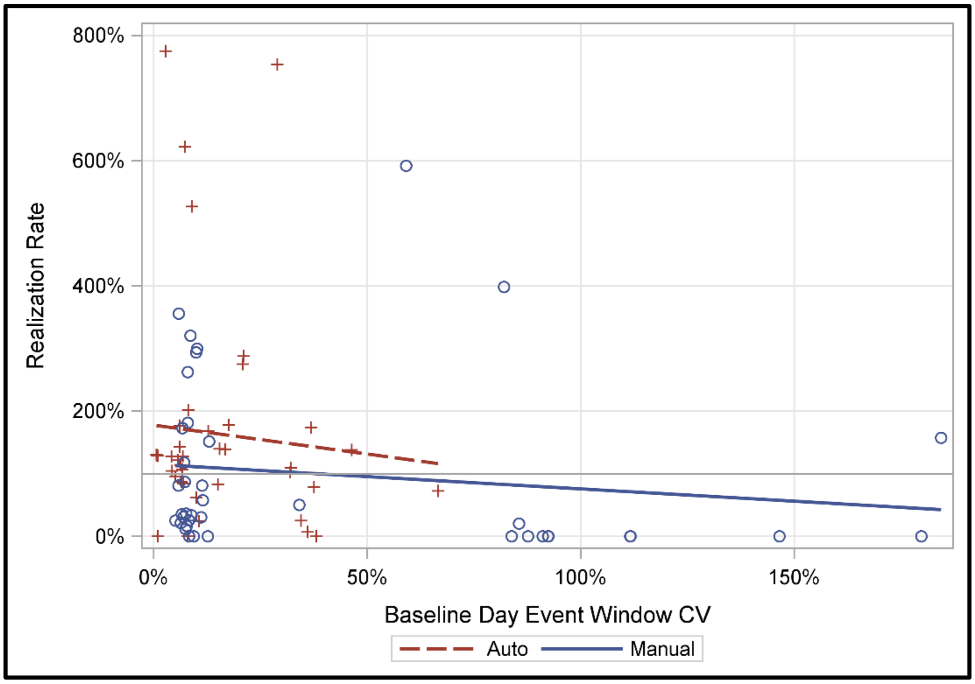
Figure 3-25: Average Realization Rate versus Load Drop



3.3.2 Realization Rate by Control Type

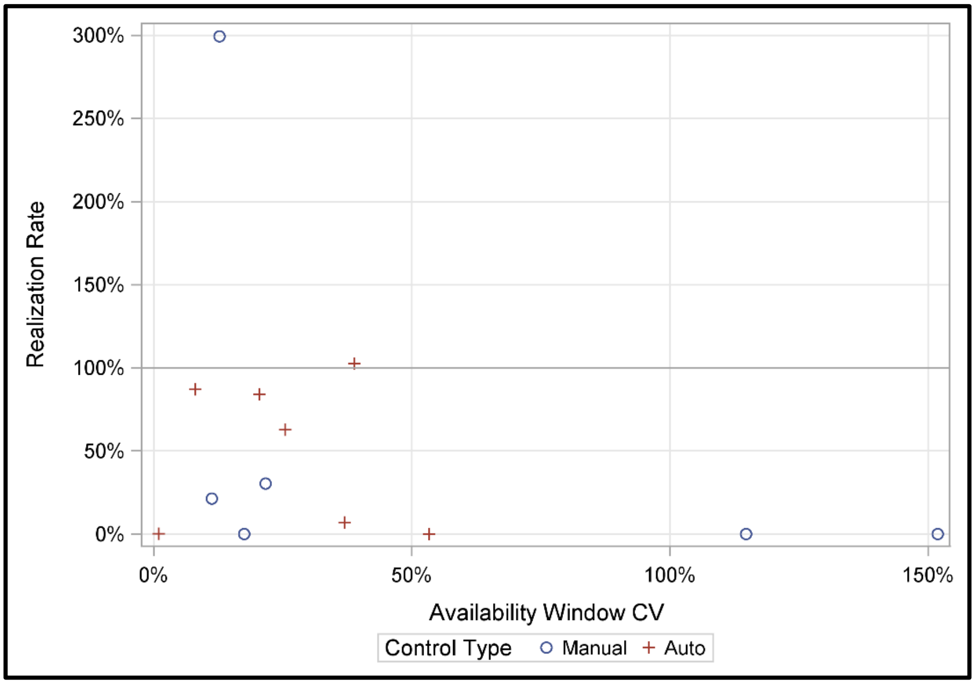
To get a better understanding of the influence of automated controls to activate load shed during an event, Itron looked at the relationship between the 2014 summer event RRs and the CV for the event window for each participant by control strategy (automated versus manual). This is shown in the scatter plot in Figure 3-26. Each participant appears multiple times in the graph. A trend line for automated control and manual control has been added to the plot. In both cases the trend is lower realization rates with increasing CV, however, the automated group shows a higher level of RR than the manual control group. What we can conclude from this is that automated controls improve performance and the higher the event window CV of a customer the lower their RR will be, on average. There still is considerable variation around these trend lines on an individual customer basis so these are clearly not the only factors affecting performance.

Figure 3-26: Realization Rate versus Load Variability



On the July 14, 2014 event where the overall performance was low, the type of control does not provide any further insight. This is shown in Figure 3-27.

Figure 3-27: July 14, 2014 Event Performance by Control Type



4

Program Implementation

4.1 Customer Outreach and Enrollment

4.1.1 Status of Program Outreach Efforts

Customer recruitment efforts have brought the total number of enabled participants to 27 as of the middle of the fourth season, despite a slow ramp-up period in the initial seasons of program implementation. Much of this improvement has occurred as EnerNOC pursued the “low-hanging fruit,” which refers to customer segments such as water authorities, heavy industry, and cold storage/refrigeration, which have flexibility in scheduling loads and more foresight operations planning. In the near future, EnerNOC expects customers in the high-tech sector among the next targeted segments.

In addition to these customers, EnerNOC reports that discussions have been initiated with 15 customers who are currently in the process of reviewing a proposal. Furthermore, 17 more customers have expressed interest in the program but had yet to pursue a proposal on account of the customer’s timeframe and priorities. As for non-participants, there are 139 customers who declined participation or were not pursued for various reasons pertaining to insufficient load, incompatible program hours, having on-site generation, or having direct access service.

Table 4-1: Status of Outreach Efforts, as of Winter 2014-15

Status	Number of Customers	Managed Accounts	Unmanaged Accounts
Enrolled Participants	27	14	13
Reviewing Proposal	15	6	9
Interested in receiving a proposal	17	6	11
Not interested or Disqualified	139	77	62

4.1.2 Outreach Approach

Assessing Awareness of Demand Response among PGE Customers

Based on feedback from PGE and EnerNOC staff, PGE customers have a weaker understanding of demand response programs compared customers in other states, such as California, that have had demand response programs for many years. Not only are PGE customers more likely to be unfamiliar with the concept of demand response, but they are more prone to refuse participation based on unsubstantiated fears, such as losing control of equipment or shutting down facilities without consent.

Thus, the greatest barrier to customer enrollment has been the lack of awareness regarding the program and demand response in general. According to PGE, the program is still in the process of creating demand for the program among customers. A PGE staff member said, "*Until more money is spent on improving customer awareness, the program is not going to meet our targeted participation numbers.*"

Interviews with two Key Customer Managers (KCMs) confirmed that customers are either completely unaware of demand response, or they are misinformed because they perceive it to mean a loss of control over their equipment. Industrial customers and municipalities were among the customers mostly likely to hold these misinformed notions. However, these KCMs are ramping up efforts to educate their customers so that they understand that demand response need not entail the complete shutdown of facility operations, but only the curtailment of select non-essential operations in their peripheral load. One KCM noted that he clarifies the concept as finding ways to reduce energy demand during events, rather than shutting down all equipment. Another KCM describes demand response as a way to take "small bites" out of a customer's energy usage during times of high energy demand. KCMs present demand response by explaining that participating allows the customer to decide what equipment can be shut down during an event and that a reduction goal can be set in such a way that it does not adversely affect business operations.

Not all PGE customers, however, are unfamiliar with demand response programs. Some customers have heard of it through participation in business associations, such as the Building Owners and Managers Association (BOMA), while other customers were reported to be familiar with demand response as a result of having facilities in states where demand response is more prevalent. One KCM noted that customers with large-scale refrigeration were more likely to be aware of demand response than other customer types.

Crafting a Marketing Message

EnerNOC and PGE have been working together to craft a program message that meets the specific needs of their customers. For demand response programs in other territories, the marketing message may focus on preventing blackouts and avoiding grid instability. PGE, however, preferred a more positive message for its program that addresses managing peak demand in a more positive light. Its reshaped marketing message focuses on topics such as sustainability and improved grid management.

KCMs were asked what marketing message they use to pique customer interest in the program. One KCM stated that he talks about program participation as a way to keep energy costs stable by avoiding the need for PGE to expand its energy capacity. If PGE had to add capacity, he says these costs would be passed on to its customers. KCMs also talk to customers about the social good as a motivation to participate, but one KCM noted that customers are more interested in their bottom line and the benefit of the program to themselves. However, both KCMs interviewed stated that the financial incentives paid for participation are not large enough to interest their customers so they must find other ways to appeal to their customers.

KCMs also suggested that when promoting the program, EnerNOC should thoroughly investigate and present curtailment strategies of similar customers when making a presentation to a potential participant. This presentation should also demonstrate how the program can work to not only provide a small financial incentive, but also to help keep future energy costs down. One KCM said the EnerNOC team should find out what message resonates with each customer and highlight it during meetings. For example, if a customer is interested in greenhouse gas reductions and portraying a green image, provide the customer estimates of carbon reductions from program participation. If the customer wants to make sure he is keeping up with his competitors, find similar customers who have already joined the program and describe their successes. With these concepts in mind, EnerNOC has developed case studies to assist customers in their decision-making process.

Customer Management

In the early seasons of program implementation, EnerNOC prioritized outreach to managed accounts as these customers typically have greater loads and thus more potential for demand reduction. For these accounts, EnerNOC may not initiate contact with the customer until KCMs have conferred with the customer to determine interest in participation. If the customer wishes to learn more about the program, the KCM authorizes EnerNOC to introduce the program and discuss the customer’s load, facility operations, and potential curtailment strategies. Prior to meeting customers about the program, KCMs request that their customers sign a waiver that permits EnerNOC access to their energy usage data to determine whether the customer is a good fit for the program. KCMs then set up the initial meetings in which EnerNOC staff introduces the Energy Partner program as a way to reduce energy usage and earn a financial incentive for participation.

The discussion with EnerNOC was held to also determine the extent to which utility involvement improves the effectiveness of customer outreach. Compared to other demand programs, PGE is among the utilities that are more involved in customer outreach, as PGE has a high level of involvement with key accounts and managing the message to the customer. EnerNOC has observed that, as a result of KCM interactions, referred customers in the PGE territory are more receptive to having initial discussions with EnerNOC than is the case with customers in other territories. Also, 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 other programs. However, despite increased initial customer interest and deeper personal relationships, no advantages were observed in terms of signed contracts. While KCM interaction is linked to more quality leads, the requirement of KCM approval makes the recruitment of managed accounts less straightforward than recruiting PGE's unmanaged counterparts. EnerNOC reported that restricted access to managed accounts may slow program growth, as these customers are typically large end-users with more potential for load curtailment.

In the third and fourth seasons of program implementation, EnerNOC began increasing outreach to unmanaged accounts, which may be contacted directly by EnerNOC without a KCM referral. EnerNOC prioritizes outreach to customers with the most potential for curtailment by scoring them according to industry type and peak energy usage.

4.1.3 The Decision-Making Process

Customer Motivations for Enrollment

This evaluation aims to characterize *how* customers learned about the Energy Partner program and *why* they decided to enroll. In most cases, customers reported that a PGE staff member, usually a KCM, first contacted them to gauge their interest in the program before referring them to EnerNOC staff. During the decision-making process, some customers had a predisposition to enroll in the Energy Partner program due to an established energy-improvement plan or an existing partnership elsewhere in the energy-efficiency community, such as with the Energy Trust of Oregon. Marketing materials, such as case studies, also played a minor role in the customer decision to participate. According to one customer, "*EnerNOC gave us case studies of similar operations, and although they weren't identical to our operations, the case studies gave us the feeling that we could participate*."

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,*" "*maintaining a good public image,*" and "*helping reduce costs related to grid infrastructure.*" A water authority stated, "*As a utility, we're a kindred spirit with PGE, so we can relate to the infrastructure challenges of peak days*." Many 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*."

In terms of monetary benefits, most customers had conservative expectations. One customer stated, "W*e're realistic and not expecting to make a substantial amount of money to add to our annual budget*." At least two customers, however, expressed greater expectations in terms of monetary payment. A customer who operated a hotel stated, "*We run tight margins, so the additional incentive was important to our decision.*" The financial aspect also sped up the decision to enroll according to one customer who said, "*We still might have signed up without the financial incentive, but it would have taken us longer to follow through*."

Addressing Customer Concerns about Demand Response

Customers were also asked to identify any concerns that needed to be addressed before committing to the program. Customers stated the importance of not incurring any financial costs as a result of participation. Customers were also apprehensive about how curtailment might affect facility operations or compromise the comfort of its occupants. At the customer level, in-house 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*." EnerNOC and the KCMs continue to work together to allay these fears by educating customers on how the Energy Partners program allows customers flexibility in shutting down non-critical equipment and opting out of events.

While follow-up discussion with EnerNOC staff were generally sufficient to resolve any of these customer apprehensions, there was some confusion. One customer stated, "*Originally, I was told that our facility would not be a good fit, because: 1) we would ruin our product if we interrupted our process; and 2) having a superior lead time is part of our competitive advantage, which I didn't want to compromise just to participate in demand response.*" The conflict was resolved by providing case studies and establishing an understanding that the customer could opt out of any event that was inconvenient.

Customer statements indicated that there is some apprehension among non-participants as they wait and see how experiences of the participants unfold. For example, a water authority said, "*I meet with other water providers and ask them why they don't participate, but they're still unsure* *of how participation would work out.*" At this point, it is not clear whether these non-participants would be more comfortable in enrolling after witnessing a peer participate.

Some customers, such as those in process manufacturing, present challenges as they may be reluctant to shut down operations for extended periods of time. EnerNOC has been working 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 the community it served. The customer stated that these risks had to be considered, especially in extreme circumstances when water supply would be needed to combat wildfires. 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.*"

KCMs confirmed that customers are concerned that their processes will be interrupted or that they would have to change their operating hours to participate when events are called. KCMs have also observed that some customers assume they have insufficient curtailable load or lack the ability to respond in the required timeframe. KCMs also reported that customers are hesitant because the financial incentives will justify the cost to their operations. The KCMs said that customers are not usually thinking about how a potential need to expand capacity would increase energy costs in the future, and that customers have a hard time considering the social benefits of participation if the cost of participating exceeds the financial incentive.

Both KCMs said that their customers who have initially said no to participating are worth re-visiting to see if they might change their minds. Production schedules, processes, and economic conditions change over time which may make customers reconsider their decision not to participate. One stated that he planned on revisiting a couple of his customers who were not interested in the program at first to see if they might be open to joining the program at a later date.

KCMs emphasized the importance of customizing presentations to address the needs and concerns of a particular customer. For example, one KCM noted that if a meeting was being held with a hotel manager, EnerNOC should become familiar with the hotel's energy-usage patterns. EnerNOC staff should also look at other hotels that might be participating so that they can present similar curtailment strategies to the customer. It helps to send a message that says, "*everyone is doing this (participating in the program), and if you do too, it is good PR and helps you get a little money as well.*"

Delivering a Proposal to the Customer

KCMs are usually involved at the beginning stages when customers are first introduced to the program and EnerNOC staff meets the customers. The KCMs were asked about the stage at which they make the customer handoff to EnerNOC. One KCM noted that he feels comfortable passing his customers onto to the implementer once discussions become more technical in regards to curtailment strategies and the installation of energy data collection equipment. The other KCM interviewed by the evaluation team said that he feels comfortable putting his long-standing customers directly in touch with EnerNOC because he knows that the customers will come to him if issues arise. Both KCMs noted that they trusted the EnerNOC staff to perform well, however, one KCM noted the importance of having experienced EnerNOC staff members present the program to PGE's customers. He has dealt with three staff from EnerNOC and he said that one should not have been interacting with customers; he did note that the other two were excellent (he noted that the less experienced staff member may no longer be part of the implementation team). The other KCM noted that EnerNOC conducted meetings that could have been better prepared, but now things are working smoothly. This KCM also mentioned that EnerNOC was responsive to KCMs' comments and suggestions during a recent meeting.

After the KCMs introduce the Energy Partner program to its customers, customer approval is necessary to share energy-usage data with EnerNOC. EnerNOC staff can then evaluate potential curtailment strategies that customers could adopt based on their energy usage and the types of equipment customers would be willing to shut down during events. These conversations become more detailed during face-to-face meetings between the KCM, the customers, and EnerNOC. At this time, EnerNOC delivers a proposal for the customer to review before signing.

Upon receiving a proposal from EnerNOC, customer staff typically reviewed the paperwork over a period ranging from 2 to 8 weeks before signing. There were a few reports of administrative delays on the customer side, such as when attorney review was required in one case, but most customers described the process as simple and convenient. The cost-free aspect of participation was important in securing approval. As one customer stated, "*If there's no out-of-pocket cost, then it's easier to get management to agree*." However, it is important to note that the participating facility may not necessarily be part of the department that ultimately receives the incentive. A KCM noted that sometimes the payment goes into the company's general budget rather than that of the participating department.

The sales process may also be more complex with national customers, than it is for customers with only a local presence. While national accounts are attractive outreach targets based on their central decision-making process, they are also more likely to present bureaucratic hurdles as there is more coordination among various corporate levels. Also, national accounts may have facilities that are dispersed among many territories, so outreach presentations to these customers may include discussions of the other demand response programs offered by EnerNOC. Presentations to local accounts, on the other hand, are tailored specifically for the PGE program, and the primary or sole decision-maker is able to make decisions with fewer hurdles.

4.1.4 The Commissioning Process

Timeline

PGE staff characterized the original enablement process as slow and in need of improvement. In the summer of 2014, PGE conducted a review that showed that the typical enablement process required 13 weeks. While most customers were being enabled in a period of 8 or 9 weeks, there were also instances of enablement taking 28 to 36 weeks. In some cases, these long enablement periods were exacerbated by changes in customer management or customer priorities. One delay was so extensive that it enabled other departments of the customer's organization to object, and the project was ultimately suspended. However, program staff have indicated that increased focus on the individual steps of enablement, especially pulse meter installation, has made the whole process more efficient. According to EnerNOC the overall timeframe from project start to completion was reduced from 23 weeks in 2013 to 12 weeks in 2014.

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*, which may occur before or after the customer signs a contract. Then, 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. The customer's role in curtailment plan development varies, as some customers may be proactive in the process while others rely entirely on EnerNOC to guide them.

EnerNOC worked with customers to develop curtailment plans to shut down equipment such as lighting, battery chargers, compressors, fan motors, air handling units, or entire process/manufacturing lines. EnerNOC and the customer also determine a specified amount of *nominated demand* (the amount of kW that the customer is expected to shed during an event). Nominated demand is determined in a conservative fashion based on site characteristics and the overall program portfolio. No action is necessary if a participant fails to meet nominated demand for an event, but repeated failure to meet nominated demand may lead to an adjustment in terms of kW. Failure to meet the nominated demand does affect the incentive payment that is made to the customer.

Some facility operations, especially uninterruptable production schedules, were deemed to be out-of-scope in a curtailment strategy. One customer said, "*We had to think about how curtailment would affect our production, so there were critical pieces of process equipment that were off the table because they would affect the quality and timing of production*." For example, production furnaces were considered out-of-scope because even if they could be interrupted, they would require too much time to start up again. One customer offered the following compromise, "*We can't shut down the furnaces down because the process needs to continue for 80 hours, but if the timing were right, I suppose we could hold off on starting the furnaces*." In another example, lighting was not considered as an option, because it would affect performance and safety in the work area. Another customer added that human activity, or the lack thereof, also plays a decision in what processes may be curtailed. The customer added, "*We have labor that operates the manufacturing equipment, and we don't want them to sit idle during events*."

One KCM also said that early on, EnerNOC had a slow, inaccurate internal analysis team that did not come up with a variety of curtailment strategies. As stated by the KCM, *"EnerNOC needed to beef up their own internal analyses to better present information to customers."* He had not interacted with the EnerNOC team in a couple of months so he stated that changes to the analytics team could have been made in the interim.

Installation of Data Collection Equipment

Once the curtailment plan has been developed, PGE installs pulse-meter equipment on the customer meter to enable the collection of interval load data. Also, in the early stages of implementation there were instances in which the installation of the PGE pulse meter was delayed beyond the 30-day period stated in the program guidelines, thus slowing the entire enablement process.

Following the installation of pulse equipment, EnerNOC's equipment is installed by a third-party subcontractor. During the program's earlier seasons, these installations were not performed in the timeliest manner possible, as subcontractors had been anticipating a greater influx of sites and had been deferring site visits in order to schedule multiple sites in clusters in attempt to minimize scheduling efforts and costs. Furthermore, EnerNOC indicated that natural lags may occur at any stage during the commissioning process, as delays may occur whenever conflicts arise between customer operations and scheduling visits. EnerNOC has discussed and resolved these matters with the installation subcontractor.

While natural lags may occur at any stage during the commissioning process customers offered mixed reviews about the performance of the installation contractors. Some customers indicated that the contractor installed the equipment with very little disruption to facility operations. According to these customers, the contractor contacted them within two months of enrollment, and only required a couple hours to install the hardware. These customers offered praise for the contractor and described staff as being helpful and accommodating. Other customers, however, found the hardware installation process to be inconvenient. While minor problems were reported, such as "*there was some confusion as to which meter was connected to which point-of-delivery ID.*" and "*the contractor crossed up the wires which affected our two meters*," more severe criticisms were also expressed. One customer stated, "*The contractor showed up unannounced, and there was a lack of communication between us, the contractor, and EnerNOC.*" The customer reported that he refused to see the contractor and had the visit rescheduled for a later date. Another customer added, "*The process went on far too long and EnerNOC should have sent a better crew.*

The installation crew did not know what they were doing, and they had limited knowledge, so I had to take my own time to help them." The customer attributed some of the difficulties to a change in contract language that prohibited EnerNOC from directly accessing the operations system, but the customer stated, "*the planning could have been smoother*."

<u>Acceptance Testing</u>

Once all the equipment is installed, 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.

In some cases, delays are an anticipated part of the commissioning process. With one customer, EnerNOC was unable to test the equipment as the customer's production equipment was undergoing maintenance for an entire month. Another customer commented on the inadequacy of the third-party contractor and reported, "*For one of our locations, they never had the equipment working, so the testing did not go well*."

There are some scenarios, such as when customer load on the day of an event is unusually high or low, where the baseline may not accurately reflect what energy might have been used during an event. As it is impossible to predict how much energy a customer would have used during an event with complete accuracy, EnerNOC uses an adjustment factor to mitigate discrepancies in energy usage. However, the lack of communication was cited as a concern by one customer. This customer indicated, "*We did the test on a 78-degree day, and we didn't notice a substantial drop because when we weren't in cooling mode, so we did another test when it was 86 degrees, but I never saw the results because EnerNOC doesn't share the data with me*."

There were other issues that had yet to be resolved with the customer at the time of the interview. One customer identified what he thought was a flaw in the baseline calculation. According to the customer, "*EnerNOC failed to account for our delay in starting up our equipment as part of our curtailment plan, so the reduction that we offered was not as much as EnerNOC anticipated. Perhaps they don't have the correct baseline, since we were not running at full capacity at the time we had our nomination test.*"

<u>Revisions to Curtailment Plan</u>

In order to assess whether their adopted plans are meeting expectations, participants were asked if any changes had made to their curtailment plans and nominated demand. According to one customer, "*We weren't able to meet the initial expectations, because in theory, we expected to be able to shut down one pump, but in practice, when you reduce one pump, it actually uses more energy to move less water, so we regrouped and changed the expectations.*" Another customer indicated that they decreased their nominated load from 300 kW to 100 kW because while the former figure reflected a best-case scenario, the latter figure was more representative of average curtailment. Another continuing participant stated that his company had signed up for 100 kW but reduced its nominated demand to 50 kW during the most recent season. The reason for this reduction was because this particular organization had been unable to meet its higher nominated demand. All three continuing participants stated that their curtailment plans were executed as anticipated and required no revisions. However, all three continuing participants reported making revisions to the amount of nominated demand. In such cases, EnerNOC works with the customer to adjust curtailment plans to change the amount nominated load while maintaining critical operations at the customer facility.

In at least one instance the curtailment plan entailed a few unexpected issues. The customer added, "*In the process of separating our circuits, we found that while we might be able to switch off a single breaker, we can't switch off an entire bank of lights, so we haven't curtailed as much load as anticipated*." The customer said that if the program provided more support in identifying how the breakers function at his facility, his organization would be able to curtail more load. One customer reported that his organization is still in the process of identifying how the circuit breakers interact with equipment.

4.2 Customer Participation and Satisfaction

4.2.1 Customer Participation

Demand Response Events

While customers reported that their experience with demand response events met expectations, several customers reported incidents of "growing pains" with the program. One customer described his issue as "self-induced," as his primary electrician had recently retired, which led to lessons learned regarding how the curtailment plan was executed. "*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 noted a minor inconvenience as curtailment reduced production, but this customer indicated that he had anticipated such a side-effect. Yet another customer indicated that manual curtailment was not without safety concerns. He said, "*I send guys out to physically shut down units, and in some cases they have to go out of a window to shut down rooftop units*." 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 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*." Water authorities cited very specific instances of when they would not be able to participate. "*We have to maintain minimum water levels,"* one water authority stated, *"so when demand is greater on our side, curtailment would put us in a position where we aren't able to maintain a safe supply of water."*

Overall, customers expected to be able to curtail more demand as they became more familiar with demand response. "*Our curtailment numbers will get better,*" said one customer, *"as we learn more about the rules of participation.*" One of the lessons learned by a water authority was that during the summer, expectations should be curbed, and that nominated demand should be revised accordingly. The customer said, "*EnerNOC bent over backwards to provide a better formula so that we could meet our nominated load*." Another customer indicated that his potential load drop was uncertain due to the summer temperatures and the lack of feedback following an event. "*EnerNOC is not sharing data with me,"* said the customer. *"I expected to see an email with the results of the test, but I never got any feedback on what we achieved*."

One of the lessons learned by EnerNOC is that the number of events called in the PGE territory varies greatly on a monthly basis, and while some months have no events, other months, such as July 2014, had as many as five events. EnerNOC suspects that some fatigue may have been experienced by participants, especially during the four-hour event that occurred on July 14th compared to the more common two-hour events. However, no customers reported the number of events during this time to be excessive.

<u>Notification and Response Time</u>

With some exceptions,[1] customers are typically notified an hour before an event is called. In terms of notification method, customers found the current system of email, text and phone call notifications to be sufficient, if not excessive. "*There was no problem in communicating the events,"* said one customer*, "In fact, it was overkill*." Another customer disliked the repetitiveness of notifications and said, "*Once we acknowledge that we are curtailing for an event, the notification process should stop, instead of redundant calls to various staff members*." This customer described the notification process as a "bombardment," and asked if it was possible to re-route notification to an assistant whenever he is away from the facility. Otherwise, customers were generally positive about the notification system in place.

When asked if the reason for a curtailment event (e.g. plant outage) would be useful information, customers indicated that such information offered no additional benefit. According to one customer, "*We already understand why these events happen, especially if it's a hot day.*" Most customers were generally uninterested in knowing the specific cause of an event and dismissed the

[1] While the mode average notification period is 60 minutes, the mean average notification period is 81 minutes. Minimum and maximum notification periods are 28 minutes and 185 minutes, respectively.

idea that they would be more likely to participate if PGE indicated that an event was being called in response to an emergency outage. Another customer said, "*It's self-explanatory, especially if it's a hot day, and we participate regardless of why an event is called*." However, one customer – a water authority - noted, "*If PGE has lost power, our operations staff would go beyond its comfort level and participate when we wouldn't normally participate, because PGE is honest in their needs and we're both in the business of providing essential services*."

Most customers indicated that it typically required ten minutes to shut equipment off and an additional ten minutes restart the equipment after an event. However, many customers were apprehensive about how the implementation of a strict 10-minute notification period would affect their ability to curtail. Such a short notification period was especially troublesome for customers on a manual curtailment plan. "*Ten minutes is not enough time,*" said one customer, "*Notification has to be a least an hour in advance to get personnel prepared for an event*." This customer added that restarting the equipment required even more time than curtailing load. "*The battery chargers use so much energy,*" he said, "*that we can't put them all back on at once, so we spend four hours doing so*."

One customer expressed a preference for earlier notification before events and said, "*If we had at least 5 hours or 24 hours, we could easily meet the requirements…If we know ahead of time, then we can plan ahead.*" Some customers, such as water authorities, can shift load in advance of an event, are thus able to shed more load with more advanced notification. For some events, PGE issued a pre-notification, in which the likelihood of an event was issued days in advance. Customers found this service to be very helpful, and one customer said, "*PGE has bent over backwards to forecast curtailment events.*"

Program Hours

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 p.m. to 7 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.

As these interviews were conducted in December 2014, few customers had actual experiences with winter events but offered several comments. According to one customer, "*PGE was very clear that the majority of the energy need is in the morning, especially during the winter, so we plan on responding in the morning and making up for our demand at the end of the shift*." 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 would be able to 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. The customer reported, however, that this practice has not been communicated to EnerNOC as a revision to its curtailment plan.

EnerNOC Software and Real-Time Data

Participants were also asked to characterize the usefulness of the real-time energy-usage data provided as part of the EnerNOC software package. Some customers, especially those with regular load shapes, found hourly usage data to be interesting, but ultimately of limited benefit. One customer who managed a hotel said, "*My fluctuations in energy usage are predictable because I see peaks and valleys when guests check-in and check-out at specific hours*." Another 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 peaks and valleys of energy usage. "*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.*" At least two customers stated that they personally did not look at the data, but there were other staff members on-site that did. One customer preferred to use SCADA software, which he felt was more sophisticated than the EnerNOC software. Access to SCADA software and its use were established prior to this customer joining the Energy Partner program.

One customer experienced difficulties accessing the web portal and logging in, but reported that EnerNOC was adequate in resolving these issues. Another customer complained that when he was first given access, EnerNOC did not provide access to all the tabs on the web portal, even though the customer received emails instructing him to check the *Earnings* tab. While the customer indicated that EnerNOC had promptly provided him with access to the additional tabs, they were still blank at the time of the interview. "*It's a communication flaw,"* said the customer, *"and EnerNOC needs provide more assistance with the website and make sure that it's working correctly*."

Customers did express a desire to have more information available on the EnerNOC software, and specifically asked to see the results of their energy reduction. "*I want to know what happened over the course of each event,*" said one customer who specified that he would be interested in the viewing the changes in energy usage that occurred over the course of an event and during the time after an event had concluded.[2] Another customer inquired into the possibility of disaggregating load to show how much power each piece of equipment consumes. *"If we had numbers on individual machines," the customer said, "it would enable me to schedule around my peaks and valleys in energy usage.*"

In the delivery of DR programs other than PGE's, EnerNOC typically bundles the implementation of DR programs with a fee-based energy intelligence software product that provides additional DR functions and capabilities. However, the fee-based software solution clashes with PGE's message of a cost-free DR platform, and has thus been excluded from the PGE Energy Partner program. However, according to EnerNOC, the software would provide more capabilities to the customer compared to the limited version that is currently offered. Discussions with current participants echoed the desire for more comprehensive software solutions.

4.2.2 Customer Satisfaction

<u>Customer Expectations of Payment</u>

The terms of the customer agreement with EnerNOC indicate that the capacity payment is equal to the product of $8.00 and the amount of delivered capacity with additional incentives available for energy payments ($0.60 per kWh) and "true-up" payments ($15 per kWh). This evaluation sought to determine whether these financial benefits aligned with customer expectations. The customers who had received compensation at the time of the interviews reported various levels of satisfaction with the amount of payment, which ranged anywhere from $37 to several thousand dollars. 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.*" The statements of continuing participants reflected their low expectations, as they said '*Payments are small but we are a small participant,"* and *"We know we set low targets, so we didn't expect a major source of revenue."*

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*."

[2] It is the evaluation team's understanding that customers are expected to have this information available under the current program structure, but this particular customer indicated that he did not have access to such information.

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. So if this is all we get, then I'm not interested in participating, because there are better things I could be doing with my time*." Other customers suggested that they would discontinue participation if the payment received did not reflect their overall effort.

There was also much uncertainty among the decision-makers regarding how much money participation yielded. Either these respondents had not yet received payment or were not in communication with the department that received payment.[3] These customers also were unsure of how or when payment would be disbursed and cited prompt notification of "payment pending" as a potential program improvement. One customer indicated that payment is delivered to an accounting department. He is 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; it's very annoying*." Nevertheless, one of the most common recommendations by customers cited was the need for more communication with customers in regards to how much money they could expect to receive. One customer said, "*I haven't received anything yet, but it would be nice to know how much we will receive rather than having to wait*." Customers cited the need to make more information available on the web portal, especially for the *Earnings* tab. In at least one case, the lack of information led to customers being misinformed about the expected payment. One customer said, "*I get emails from EnerNOC telling me to look for earnings on my web portal, but it's all blank, so I guess I haven't earned anything even though I surpassed my nominated demand in five events*." The customer added, "*At the end of the day, all I want is a check*."

Cost-Effectiveness of Participation

This evaluation also sought to determine whether participation in the Energy Partner program is cost-effective activity for customers. When asked to estimate the value of the program relative to their efforts, customers considered such items as financial benefits, electricity rates, and labor costs. Two continuing participants with automated response cited the low-impact of participation as a confirmation of the cost-effectiveness. One of these participants said, *"The way we have it set up there is little cost to participating."*

However, at the time these interviews were conducted, most participants, especially new participants, indicated that they didn't have sufficient information to determine whether participation was cost-effective. One such customer said, "*I want to know how much savings we*

[3] It should be noted that many of these customers had only participated in the Summer 2014 season at the time interviews were conducted in December 2014, so these statements do not necessarily indicate that payment was actually delayed.

produced, and how that translates to dollars; but there's nothing on the web portal to indicate as much; EnerNOC needs to communicate more and improve its website tool." Another customer added that he would like PGE to provide information regarding the cost per kW according to different times of the day. "*With all the surcharges,*" the customer said, "*It's hard to figure out whether it's worthwhile, because it would involve PGE telling us what the rates would have been had we not curtailed for a specific event.*"

Most importantly, many new customers were undecided on the issue of cost-effectiveness because they had not yet received payment for program participation. One such customer indicated that he would wait until receiving a check and discuss it with management before deciding to continue participation. He said, "*I'm waiting to see what the return is, but it's been five months since we first started and no one is communicating with me about these events or told me about a check, and the lack of communication frustrates me*." Even if the exact financial amount was unavailable, customers indicated that acknowledgement of curtailment and an indication of future check disbursal would be welcome feedback.

A few customers expressed their doubts regarding the financial benefits of participation. One such customer said, "*It takes my staff six hours to shut down equipment and bring it back online, so if the capacity payment doesn't meet my labor costs that we have to endure during a shutdown, then I'll start questioning whether or not this a smart activity for our business*."

Even those customers who participated for the social benefits do not dismiss the importance of financial benefits. When asked whether the program was a cost-effective use of his organization's resources, he said, "*Ask me again in a year, because right now it's a politically-driven feel-good opportunity in which we're happy to participate, but I don't know yet how to quantify the value of participating and at what point it becomes too much of a hassle*."

Customer Satisfaction and Feedback

When asked to describe their level of satisfaction with the program thus far, customers were generally mixed in their reviews, ranging from satisfied to very unsatisfied. 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.

The continuing participants had been asked about the reasons they chose to participate in the Energy Partner program. Two customers cited the financial incentive associated with curtailment as a main reason, which is interesting considering these participants noted that they did not necessarily expect to receive large returns from curtailing their energy usage during events. One continuing customer stated that that the decision to participate was made from a public relations perspective and a long-standing relationship with PGE.

In general, the continuing participants were satisfied with their participation in the program and reported no changes in satisfaction since they were interviewed during the Winter 2013-14 season. One customer noted that the automated aspect of demand response made participation extremely convenient. Another customer stated that participation was a good way to meet a need for PGE and that the company was more interested in being a community partner. The third customer likes the availability of the real-time data since it shows how much energy the company uses and where it might be able to improve energy efficiency. He said that knowing about the company's energy use in such detail helps it plan budgets better. One continuing participant said he would like to see how his company performed in a report format at the end of each season.

KCMs were asked about what they think customers like about participating in the program. One noted that his customers like the social and financial benefits, since this customer is conservation-minded. The other KCM noted that customers who participate for sustainability reasons tend to like the program. While the financial incentives are low, according to both KCMs, the benefits from reduced energy use during events were also considered to be a feature that their customers appreciate about the program.

While two of the continuing participants gave no reasons to be dissatisfied with the program, one noted that his company still has not been able to participate in several events because of when they are called. After season two, this customer said, "*I hope that there are more events called earlier in the day so that we can participate.*" After season three concluded, the customer said, "*We are usually winding down when events occurred. If we were running two shifts, then it would be financially beneficial to participate, but we do not have enough business to do this right now.*" The timing of events was something he noted could be varied in order for his company to participate and reap a financial benefit.

When asked how the program could be improved, customers re-iterated the items stated earlier in this document. In summary, customers asked that future program offerings included streamlined equipment installation, more assistance with curtailment strategies, better notification of payment, greater incentive amounts, more information on the web portal, better access to curtailment figures, and more follow-up from EnerNOC after an event. All of these topics are explained in further detail in the relevant sections of this evaluation.

<u>Customer Retention</u>

At the time of the interviews, seven[4] of the eleven customers interviewed said that they would likely continue participating in the Energy Partner program. These customers indicated that they would very likely continue to participate as long as the program remains the same. However, one participant noted that there has been some discussion as to whether the company should continue since they are not able to participate during the events due to the times they are called. According to this customer, *"There is some push and pull from management about whether we should participate. I think we should stay because we don't want to get out, and then change our production schedule and not be a part of the program. …We wouldn't want to get out, then regret this and have to come back in."*

One customer, however, indicated that he was not likely to continue participation. This customer stated that he would no longer curtail during events because it was not a financially worthwhile activity. He indicated that rather than officially dropping out, he would ignore demand response events.

At the time of the interview, three customers had yet to decide whether they would continue participation. They indicated that they would wait until after the Winter 2014/15 season ended to determine their participation status. For one customer, the decision lies with the board of directors, with whom he expected to discuss the financial return that participation has earned. Customers indicated that the decision would be dependent on whether or not certain conditions were met. For example, one customer specified that his future participation would depend on the amount of payment received. Another customer indicated that he would continue participating as long as the program doesn't adopt a 10-minute notification period.

4.3 Scalability

PGE's Energy Partner program was initially launched as an automated demand response program that was intended to serve as a capacity resource during critical events, such as when inclement weather results in large load increases or when there is an unexpected decline in wind or hydroelectric generation. The goal of the program was to enroll enough participants to provide 9 MW of nominated demand by the end of 2014 and 25 MW by 2017. Based on discussions with PGE and EnerNOC, however, it appears as though the Energy Partner program is behind schedule to meet its demand reductions goals. As of January 2015, the program was able to nominate 6.7 MW of demand, which is somewhat less than the stated goal of 9 MW by the end of 2014. Despite this shortfall, PGE staff members were pleased that much progress had been made in overcoming initial barriers that were encountered early in the program's rollout. At the time of discussion for

[4] All three continuing participants indicated that they would likely continue participation.

this evaluation, PGE staff remained hopeful that 9 MW of nominated demand could be met by the end of the fourth season as EnerNOC continues to enroll new customers.

While the Energy Partner program is behind its current goal to provide 9 MW of nominated demand by the end of 2014, the likelihood of meeting the ultimate goal of providing 25 MW by 2017 would be increased by making changes to improve program design and customer awareness. The program has yielded approximately 7 MW of nominated demand to date and this is expected to increase as additional customers are recruited to the program. In order to understand the gap between the program's current nominated demand and its goal of 25 MW by 2017, this evaluation presents background related to customer recruitment and the factors that affect the success of demand response programs in PGE territory. The implementation of the program design changes presented in this evaluation will improve the program's progress towards its ultimate goal of 25 MW. The program was launched as a pilot and its successes continue as additional PGE customers enroll in the program and nominate demand.

4.3.1 Likelihood of Program Success at Scale

In its 2013 Integrated Resource Plan Report[5], PGE projected generally balanced supply and demand conditions with a slight surplus during the 2016 to 2019 years. This therefore was an ideal time for PGE to launch the Energy Partner pilot program to assess how much demand reduction it can be expected to yield, especially given the projected need for capacity in future years.

In 2013, EnerNOC performed an initial market assessment to identify potential key demand response program business types according to their load size and hours of operation. This assessment identified such industries as manufacturing, light industrial, lumber, asphalt, and concrete & gravel customers as prime candidates for the PGE Energy Partner program. Other industries, such as cold storage, food & beverage, and wastewater management were considered as potential targets, but were not expected to be able to meet program hours or demand reduction requirements.

After the first season of program implementation, these industries were reevaluated based on EnerNOC's experiences with PGE customers. Difficulties with recruitment were experienced by EnerNOC, but the MW goals of the program remained the same. Some industries, such as manufacturing and light industry, met expectations as prime candidates for program participation and will continue to be key industries targeted for recruitment. Other industries, such as lumber and concrete & gravel, have been more difficult to engage than had been expected, although EnerNOC continues to pursue these customers. Industries that were not expected to meet program requirements, such as cold storage, food & beverage, and wastewater, offered more opportunities

5 Portland General Electric Company, 2013 Integrated Resource Plan, March 2014. Pp. 3. https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2013_irp.pdf

than had been expected and are now considered key industries. Food & beverage customers, for example, are able to curtail multiple types of load and wastewater facilities are good candidates based on their large load size, suitable hours of operation, and the ability to respond quickly to called events.

4.3.2 Barriers to Full-Scale Program

A number of barriers limit the demand response potential of the Energy Partner program including both program design factors as well as the demand response landscape of the Pacific Northwest.

Limiting Factors in the Pacific Northwest

The Pacific Northwest has a number of factors that affect the region's adoption of demand response programs. Unlike states like California, there are differences in weather, electricity generation capacity, and business types and sizes that have made DR less common in the state of Oregon. This region has had a significant supply of relatively inexpensive hydro power, which has resulted in low stable energy prices. There has also been enough supply, even during peak energy demand that to date has not caused significant capacity shortages. A third factor that affects the prevalence and reliance on DR programs in this region is that it is a winter peaking system. DR programs have shown success in states that have peak energy demand in summer months. Though these factors have historically made demand response programs less common in this region, capacity shortages are predicted for the future and DR programs may be a way to address this concern.

An estimate of the average summer energy demand of customers who are excluded from participating in the Energy Partner program was made based on data made available by PGE[6] and shows that on average, the direct access and dispatchable standby generation customers' demand during the summer months of July, August, and September is approximately 240 MW per month. This represents the maximum demand potential that is unavailable to the Energy Partner program or not targeted due to its current program structure. Any estimate of demand potential for the program should be reduced by the achievable demand response potential of the excluded customers.

Limiting Factors in PGE Territory

The potential market for the Energy Partner program is a subset of the total market of customers who are capable of load curtailment generally speaking. Theoretically, those customers who are eligible to participate in the program are PGE customers on Schedules 47 and 49 (small and large nonresidential irrigation and drainage customers) and Schedules 83, 85, and 89 (large

[6] PGE provided monthly kWh and kVAR data for direct access and distributed standby generation customers for the past year. To arrive at an estimate of monthly demand for these customers, it was assumed that kW = 1.33*kVAR. The estimated kW for each of these customers was summed and the average was taken across the sums of kW for the summer months to arrive at an average monthly energy demand for these excluded customers.

nonresidential standard service customers on various schedules with demands ranging from as low as 31 kW to over 1000 kW). However, any customers with an Electric Service Supplier (ESS), customers enrolled in other PGE DR programs (e.g., Schedule 77) are excluded from enrolling in the program. Furthermore, the program does not currently pursue customers with dispatchable standby generation (e.g., Schedule 200). This has limited the pool of potential participants that could nominate demand and participate in the program. In discussions with EnerNOC about customer recruitment, it was noted that a larger number of otherwise ideal program candidates than expected has proven to be ineligible for the Energy Partner program. EnerNOC found that large end-users and customers with a predisposition to reduce energy costs are more likely to be customers who have an Electricity Service Supplier (ESS) or participate in other PGE DR programs.

EnerNOC staff also stated that the availability of customers with large amounts of curtailable load is far less than they had expected. As a result, the current program structure is dependent upon the enrollment of smaller end users. To maximize the return on recruitment efforts, EnerNOC prefers customers with at least 100 kW of curtailable load during program hours. But, according to EnerNOC staff, "*We don't have enough of these (eligible) large customers in the PGE territory, so by seeking more customers with smaller load (e.g. 30 kW), the 25MW goal may still be attainable.*" These customers typically have less peripheral load and therefore have fewer opportunities to curtail load. EnerNOC also indicated that given the amount of time and effort required to enroll any customer, regardless of load size, the returns on recruitment efforts diminish as the customer mix is weighted more towards small-load customers. As a result, EnerNOC expressed a preference for a greater mix of participants in terms of load sizes. To meet the nominated demand goals for the program, EnerNOC has had to recruit a larger percentage of smaller customers than it normally would for a demand response program.

EnerNOC also described the barriers to customer enrollment that were encountered during the first season of program implementation. A commonly encountered barrier is that hours of operation prevent customers from curtailing load during the morning and evening hours of the winter season. School districts, for example, are unable to shut off heating loads during the program hours for winter mornings (6 a.m. – 11 a.m.) and are thus unable to curtail much load during these times. Other customers, such as municipalities, who also share their load among many small meters, have been unable to participate for these same reasons. As a result, EnerNOC expects the portfolio to provide less capacity in the winter than in the summer, even though the overall portfolio is on track to meet equal reduction goals for both seasons.

4.3.3 Opportunities for Improvement

In addition to the efforts KCMs are making to educate their customers about demand response and EnerNOC's continued recruitment of customers to the program, one element that PGE mentioned considering is how it could make the program available to customers who are currently excluded from participation. As mentioned by EnerNOC and PGE, there are a lot of customers who have the potential to nominate relatively large demand reduction amount but are currently unable to participate in the program. A methodology to somehow include some of the ESS and distributed generation customers into the program would help the program come closer to its goal of 25 MW of nominated demand by 2017.

Additional recommendations to expand the program are detailed in the findings and recommendations section of this report. However, EnerNOC did caution that any comparisons between other DR programs and the PGE Energy Partner program should be limited as it would not be an "apples-to-apples" comparison. EnerNOC indicated that while the individual characteristics of the PGE program are not unique in themselves, the combination of these aspects makes the PGE program unique. EnerNOC manages many other programs, including those with a 10-minute notification period, equal demand reduction goals for summer and winter, and utility involvement in customer outreach, but only the PGE program combines all of these elements. The sum of these characteristics adds a unique complexity to the PGE program and EnerNOC continues to learn more about how these characteristics interact.