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May 31, 2017

Via Email
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OPUC Filing Center
201 High Street SE, Suite 100
PO Box 1088
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RE: **2017 Smart Grid Report**

Commission Order No. 12-158 (Docket No. UM 1460) directed PGE to submit annual reports beginning June 2013, regarding our strategy, goals and objectives for adoption of smart grid technologies and the status of our smart grid investments. In addition, PGE was required to provide opportunities for the public to contribute input on PGE's smart-grid investments and applications.

In formulating PGE's 2017 Smart Grid Report, PGE provided a draft report to receive and consider feedback from stakeholders. Pursuant to Order No. 12-158, PGE provides the attached 2017 Smart Grid Report.

If you have any questions or require further information, please call me at (503) 464-8937. Please direct all formal correspondence and requests to the following email address: pge.opuc.filings@pgn.com.

Sincerely,

Stefan Brown
Manager, Regulatory Affairs

cc: UM 1460 Service List
UM 1657 Service List
UE 294 Service List
LC 66 Service List

Smart Grid Report

JUNE 2017

Contents

Tables and Figures

Acronyms

ADR ....Automated Demand Response
AMI ....Advanced Metering Infrastructure
AC ....Alternating Current
AGC ....Automated Generation Control
AMI ....Advanced Metering Infrastructure
ANSI ....American National Standards Institute
ARRA ....American Reinvestment and Recovery Act
BIS..Battery Inverter System
BPA ....Bonneville Power Administration
CAA ....Community Action Agencies
CCS..Command-and-Control Systems
CELID..Customers experiencing long interruption durations
CEMI ....Customers experiencing multiple interruptions
CIP...Critical Infrastructure Protection
CIS ....Customer Information System
CPP..Critical Peak Pricing
CVR ....Conservation Voltage Reduction
DA ....Distribution Automation
DC ....Direct Current
DGA...Dissolved Gas Analyzer
DER ....Distributed Energy Resources
DLC..Direct Load Control
DMS ....Distribution Management System
DR ....Demand Response
DSG ....Dispatchable Standby Generation
DTS..Distribution Temperature Sensing
EMS...Energy Management System
EPRI...Electric Power Research Institute
EV..Electric Vehicle
FC ....Fuel Cell
FCI ....Faulted Control Indicator
GIS...Geographical Information Systems
HRZ ....High Reliability Zone
ICT ....Information & Communication Technology
IED...Intelligent Electronic Device
IHD ....In-Home Display
IRP...Integrated Resource Plan
kW...Kilowatt
kWh ....Kilowatt-hour
MDC ....Meter Data Consolidator
MDMS...Meter Data Management System

MW ....Megawatt
MWa ....Average Megawatt (8,760 mega-watt hours)
MWh..Megawatt-hour
NEEA ....Northwest Energy Efficiency Alliance
NERC ....North American Electricity Reliability Commission
NIST..National Institute of Standards and Technology
OMS ....Outage Management System
O&M ....Operations and Maintenance
OPUC..Oregon Public Utilities Commission
PCC...Portland Community College
PDC ....Phasor Data Concentrator
PGE ....Portland General Electric
PMU ....Phasor Measurement Unit
PNNL ....Pacific Northwest National Lab
PV..Photovoltaic
PSU ....Portland State University
RAS..Remedial Action Schemes
RD&D ....Research, Development and Deployment
RTCA ....Real-Time Contingency Analysis
RTU ....Remote Terminal Unit
SAM ....Strategic Asset Management
SCADA..Supervisory Control and Data Acquisition
SE ....State Estimator
SEI ....Software Engineering Institute (of Carnegie Mellon)
SEGIS..Solar Energy Grid Integration Systems
SGMM..Smart Grid Maturity Model
SPS ....Special Protection Scheme
SSPC ....Salem Smart Power Center
SSPP ....Salem Smart Power Project
T&D..Transmission & Distribution
TIS ....Transactive Incentive Signal
TOD..Time-of-Day
TOU..Time-of-Use
USDOE ....United States Department of Energy
VAR ....Volt Ampere Reactive
WECC ....Western Electricity Coordinating Council
WISP ....Western Interconnection Synchrophasor Program
WTC ....World Trade Center (Portland, OR)

Executive Summary

Background

This report is PGE's fifth Smart Grid Annual Report filing in compliance with OPUC Order No. 12-158 in Docket No. UM 1460 and includes an update on PGE's smart grid initiatives.

Strategy

In 2015, PGE commenced a process to identify gaps and dependencies between PGE's strategies and to develop a clear, cross-company vision, road map, and strategic approach to integrating and deploying smart grid technologies. Informed by the Smart Grid Maturity Model, the task force outlined a three-staged iterative approach that will enable PGE to build an integrated grid that delivers value to all customers:

- Model & Monitor (Plan Ahead)
- Engage (Successfully Pilot)
- Integrate (Move to Scale)

This process is proactive and collaborative enabled by an on-going stakeholder dialogue. These efforts will be information-driven and evolutionary (not revolutionary). Included in the report is a roadmap which outlines the vision for utilizing this strategy over the next 5 years and ties individual smart grid initiatives to the four goals identified in Order No. 12-1258:

- Enhance the reliability, safety, security, quality, and efficiency of the T&D network
- Enhance the ability to save energy and reduce peak demand
- Enhance customer service and lower cost of utility operation
- Enhance the ability to develop renewable resources and distributed generation

System Planning

PGE includes Smart Grid technologies as viable resources in the IRP as they mature, similar to the way cost-effective energy efficiency and demand response are considered. As such, many of our Smart Grid initiatives will continue to be part of a continued two-way conversation between program/system planners and the IRP team and will be included in PGE's IRP process. In 2015 and 2016, PGE held 9 stakeholder workshops in the IRP planning process which included smart grid-related content.

As a condition of PGE's 2016 Smart Grid Report, the OPUC requested that PGE identify resources needed to commence distribution resource planning. Creating a Distribution Resource Plan ("DRP") that identifies how and where DERs may be able to improve the reliability, affordability, and sustainability of PGE's electric service is a challenging undertaking. Best practices and modeling tools are, in many cases, under development or non-existent.

PGE estimates approximately $850,000 to commence distribution resource planning. An initial deployment of a DRP will likely just be a stepping stone. Outputs would help us learn and inform better practices going forward. To receive the full value from a hosting capacity analysis and other elements of a DRP, additional investments would be necessary.

Smart Grid Initiatives

PGE has made considerable investments in smart grid initiatives, staff, and research. PGE has completed, is deploying, or is considering more than 50 smart grid initiatives across the Company, spanning three categories: foundational, grid optimization, and customer engagement.

Consistent with our Smart Grid Strategy, PGE is always monitoring the landscape for emerging technologies and opportunities to create value for our customers.

The roadmap on the following pages includes our best estimate for when these initiatives and use cases will evolve at PGE over the 5-year time frame.

Related Activities

In addition to PGE's smart grid initiatives, PGE maintains strong business practices that support PGE's efforts in Smart Grid development. PGE's Strategic Asset Management program helps prioritize how the Company deploys smart grid initiatives. The Company's efforts in physical security, such as vegetation and wildlife management, help ensure smart grid investments realize their full value. Additionally, PGE's cybersecurity and data privacy policies and process position PGE to minimize risk of cyberattack or loss of critical data. PGE's commitment to low-income customer engagement ensures programs are designed and targeted to reach all customers.

As PGE is developing a portfolio of smart grid technologies, PGE must have means to evaluate the costs and benefits of new resources to evaluate their benefit to the system, our customers, society, etc. Because each of these DERs is unique in how they provide benefit to the system, PGE looks forward to future stakeholder engagement on how to standardize a variety of efforts underway to quantify and determine value streams associated with various types of DERs.

Roadmap

Foundational: Hardware and software that enable deployment of smart grid initiatives, allow customers to realize maximum value of smart grid initiatives, and improve cybersecurity.

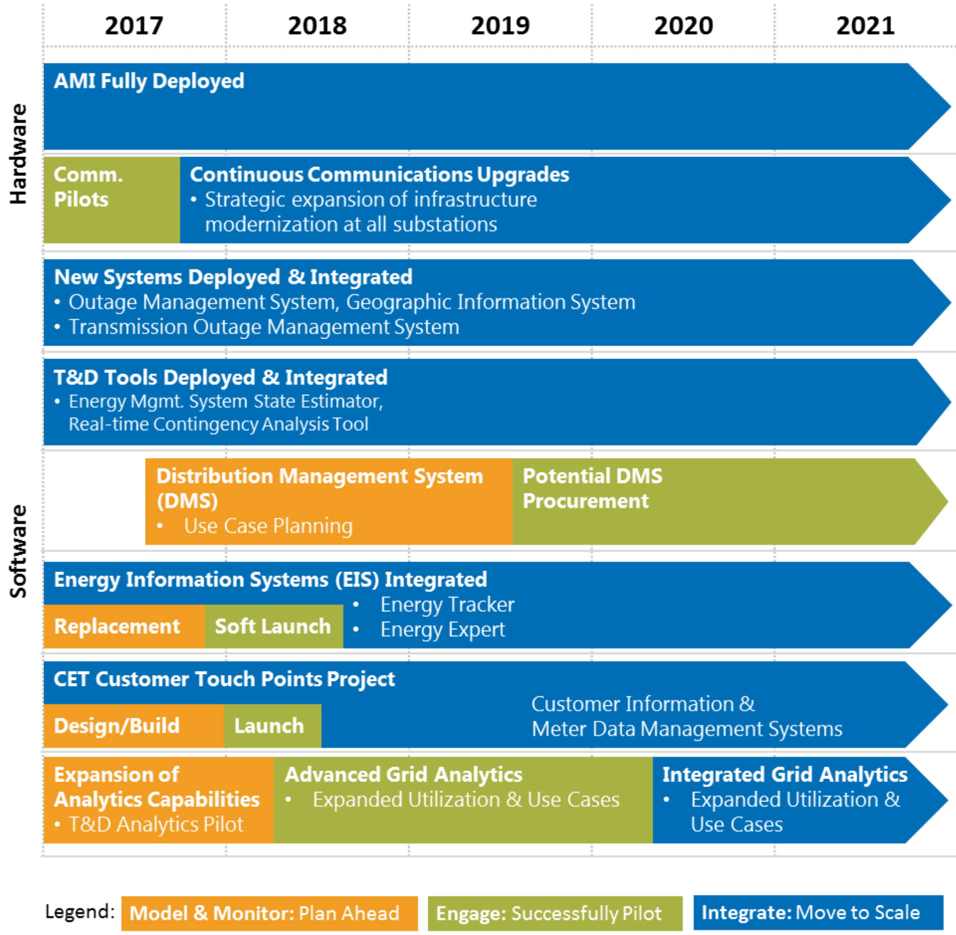


Table 1: Foundational Key Metrics Summary

Metric	2012	2013	2014	2015	2016
Total Number of Smart Meters Deployed	862,331	871,819	880,836	862,242	871,709
# Customers Initiating AMI Opt-Out	133	118	136	94	62
Cumulative # Customers Choosing No AMI	4	9	15	22	10

Grid optimization: transmission, substation, and distribution system investments in hardware, software, technologies, and processes that improve system reliability and efficiency, increase flexibility of grid integration, enhance the ability to reduce peak demand, and reduce overall utility operation costs.

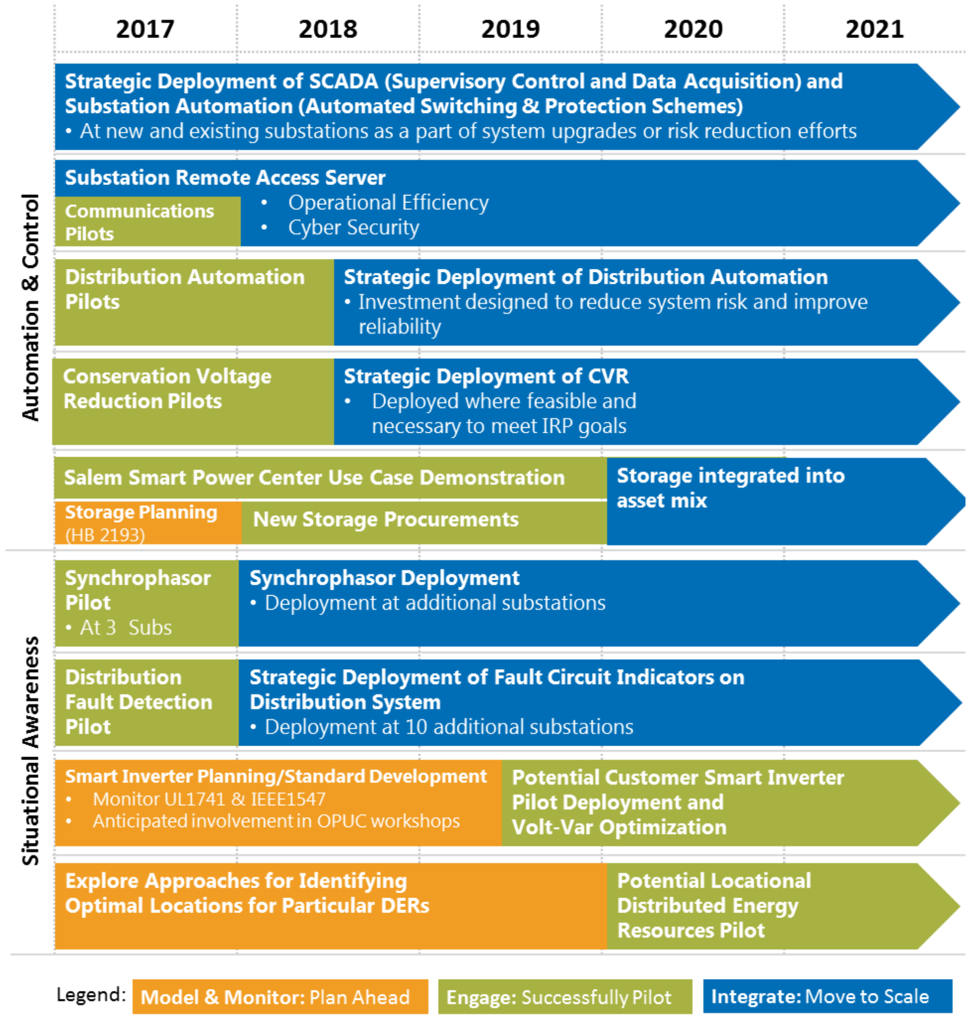


Table 2: Grid Optimization Key Metrics Summary

Metric	2012	2013	2014	2015	2016
% Substations with SCADA	70%	70%	74%	77%	78%
% Critical Transformers w/ DGA	68%	68%	68%	68%	85%
Efficiencies realized through CVR (MWh)	-	356	768	-	
Available Storage Capacity (MW)	5.00	5.00	5.00	5.00	5.01
Available Storage Energy (MWh)	1.25	1.25	1.25	1.25	1.28
# of Energy Storage Locations	1	1	1	1	2

Customer engagement: investments in pricing, demand response, and distributed energy resources programs that make customers active participants in the provisioning of energy services, while improving the customer experience, saving energy, enhancing reliability, and reducing peak demand.

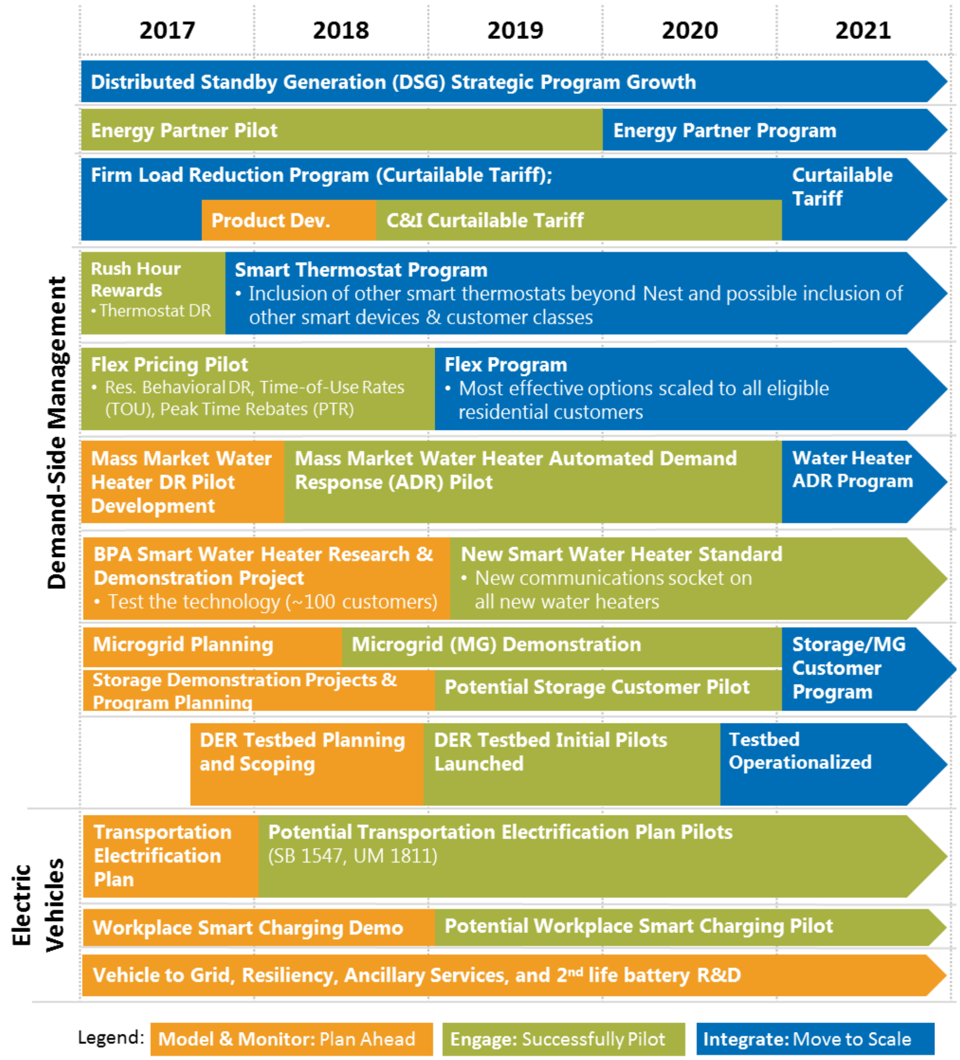


Table 3: Customer Engagement Key Metrics Summary

Metric	2012	2013	2014	2015	2016
Est. Number of EVs in Service Area	1,600	4,033	5,500	6,300	8,091
# Customers that have utilized Energy Tracker	80,430	124,948	167,466	204,763	235,915
# of Customer Accounts on TOU Rate Schedule	4,049	4,116	4,226	4,210	5,490
# Customers participating in DSG	29	33	34	35	38
Dispatchable capacity of DSG (MW)	79.4	83.4	94.0	106.8	116.9
Capacity of customer-owned renewable (MW)	28.6	35.8	44.5	54.2	73.2
# Customers participating in DR	791	599	27	184	16,467
Winter max available capacity of DR (MW)	16.2	17.4	24.6	24.7	16.3
Summer max available capacity of DR (MW)	16.1	16.4	21.0	27.4	18.7

Section 1. Background

1.1. Smart Grid Report History and Purpose

In 2012, the OPUC issued Order No. 12-158 in Docket No. UM 1460 to establish the Commission's smart grid policy goals and objectives, utility reporting requirements, and guidelines for utility actions related to smart grid:[1]

OPUC's Policy Goals and Objectives:

The Commission's goal is to benefit ratepayers of Oregon investor-owned utilities by fostering utility investments in real-time sensing, communication, control, and other smart grid measures that are cost-effective to consumers and that achieve some of the following:

- *Enhance the reliability, safety, security, quality, and efficiency of the transmission and distribution network*
- *Enhance the ability to save energy and reduce peak demand*
- *Enhance customer service and lower cost of utility operation*
- *Enhance the ability to develop renewable resources and distributed generation*

Required Elements of Annual Reports:

- *Smart Grid Strategy*
- *Status of Smart Grid Investments*
- *Smart Grid Opportunities and Constraints*
- *Targeted Evaluations*
- *Related Activities*

This report is PGE's fifth report in response to Order No. 12-158:

Table 4: History of PGE Smart Grid Annual Report

Date	Order No.	Event Detail
05/08/2012	12-158	OPUC Outlines smart grid goals & reporting requirements
06/01/2013	NA	2013 Smart Grid Annual Report Filed
08/28/2013	13-311	Acceptance of 2013 Smart Grid Annual Report
06/01/2014	NA	2014 Smart Grid Annual Report Filed
10/01/2014	14-333	Acceptance of 2014 Smart Grid Annual Report
05/28/2015	NA	2015 Smart Grid Annual Report Filed
10/13/2015	15-314	Acceptance of 2015 Smart Grid Annual Report
05/31/2016	NA	2016 Smart Grid Annual Report Filed
10/20/2016	16-405	Acceptance of 2016 Smart Grid Annual Report

1.2. OPUC Recommendations

In response to PGE's 2016 report, the OPUC made several recommendations in Order No. 16-405, which are summarized in Table 5.[2] Each recommendation is addressed in this report on the page listed.

Table 5: Summary of Recommendations from Order No. 16-405

Category	Recommendation	Page(s)
Cost Effectiveness	Provide the results and work papers used in the cost-effectiveness evaluation of the Energy Partner Pilot before the next Smart Grid Report filing.	158
Marketing	In future Smart Grid Reports, include copies of new or updated DSM and DER marketing material as an appendix.	102
Cost Effectiveness	Conduct a stakeholder process to develop metrics in which to compare cost effectiveness methodologies across all current and future DER and DSM efforts.	76, 145
Metrics	Provide data on its Energy Partner, Flex: Pricing Research - Peak Time Rebate and Next Rush Hour Rewards pilot programs.	44, 45, 46
Distribution Resource Planning	Identify and discuss the system and Company resources necessary to begin evaluation of DER value to customers and the additional resources needed to commence distribution resource planning.	25
Reporting Process	Participate in a staff-led stakeholder workshop process to determine if and what changes should be made to the smart-grid reporting process.	24

1.3. Stakeholder Engagement

In preparation for filing this report, PGE provided key external stakeholders opportunities to contribute to this Smart Grid Report. Per request of stakeholders after the 2015 reporting process, stakeholders received two weeks to review the draft report:

Table 6: Stakeholder Engagement

Date	Milestone
04/28/2017	Cost Effectiveness Workshop
05/08/2017	Draft report shared with stakeholders
05/15/2017	Smart Grid Report Guidelines workshop
05/17/2017	Smart Grid draft report call with stakeholders
05/19/2017	Last day comments received

PGE received informal comments from OPUC Staff. Where applicable, PGE has included additional information in this report to address stakeholder comments.

PGE also conducts customer research on a regular basis to ensure our vision aligns with customer expectations regarding smart grid engagement. In 2016, PGE engaged customers on a variety of smart-grid related topics:

- Renewable and community solar focus groups
- EV buyer focus groups

From discussions with stakeholders we understand the Smart Grid Report is used for a variety of purposes:

- As a reference document and a place to monitor and track various initiatives,
- A tool to resource plan and to provide outreach to smaller municipal utilities, and
- A tool to provide vendors insights into upcoming initiatives to help plan for potential RFPs.

Section 2. Smart Grid Approach

2.1. History of Smart Grid Strategy

PGE has previously reported a smart grid strategy consistent with OPUC's goals:[3],[4]

- *Enable Smart Grid capabilities when equipment fails or becomes obsolete.*
- *Be strategic with regard to the Smart Grid technologies pursued, looking for opportunities to provide customers with more choices, higher reliability and greater value.*
- *Use proven and interoperable technology as industry standards emerge (when feasible).*
- *Work collaboratively to demonstrate technologies in the early stages of commercialization, when those technologies address an immediate need (e.g., renewables integration) or have a particularly strong value proposition.*
- *Track early stage technologies through industry organizations, such as the Electric Power Research Institute (EPRI) and standards development through working groups, including the National Institute of Standards and Technology (NIST) and the Smart Grid Interoperability Panel (SGIP).*

This strategy was valuable in guiding PGE research, investment, and planning around smart grid technologies. Due to the constantly evolving, cross-functional nature of smart grid deployments, PGE has recognized the necessity to develop a more integrated strategy and vision of its future state to maximize the benefits of smart grid investments.

In 2015, PGE commenced a process to identify gaps and dependencies between PGE's strategies and to develop a clear, cross-company vision, road map, and strategic approach to integrating and deploying smart grid technologies. A smart grid task force evaluated industry best practices in smart grid deployment to update PGE's smart grid vision and to establish a smart grid future state and road map. The task force explored inputs from key subject matter experts from across the organization to define a model that is best for PGE and its customers.

2.1(a) Smart Grid Maturity Model

Prior to developing a target future-state for PGE's smart grid, the task force evaluated its current state utilizing the Smart Grid Maturity Model (SGMM). The SGMM was created by a coalition of electric utilities and IBM in 2009 to serve as a strategic framework for utilities to develop explicit plans to advance smart grid infrastructure. The model is now maintained by Carnegie Mellon University's Software Engineering Institute (SEI) and has been utilized by dozens of utilities, including San Diego Gas & Electric, Austin Energy, Pacific Gas & Electric, Puget Sound Energy, and Duke Energy.

SGMM divides and evaluates the utility in eight domains to facilitate a framework for better understanding the extent of smart grid deployment and a context for establishing strategies and implementation plans.

PGE established smart grid working groups that align with the SGMM's eight domains:

1. Strategy, Management, and Regulatory
2. Organization and Structure
3. Grid Operations
4. Work and Asset Management
5. Technology
6. Customer
7. Value Chain Integration
8. Societal and Environmental

The SGMM process is essential for developing a road map that is consistent with PGE's current state and corporate strategies. It calls for:

1. **Gather Information:** Evaluation and documentation of PGE's current state
2. **Analysis**: Develop pillars, benchmark performance, and identify best practices
3. **Articulate Vision & Future State:** inter-departmental and stakeholder input
4. **Vision & Road Map:** gap analysis, identification of key dependencies

PGE presented its strategic approach and 5-year vision in a public meeting on October 12, 2015 and its 5-year roadmap at public meetings on March 15, 2016 and October 20, 2016.

2.2. Principles

To align our stakeholders and to guide our planning, we have established a set of guiding principles that shape our thinking and inform program design and technology deployments:

Table 7: Smart Grid Principles

No Regrets	Operationally Efficient	Innovative	Value Add
• Change will happen: sense and plan for the disruption; pilot quickly and analyze data	• Redefine operations to meet customer exceptations	• Build upon the successes of new technologies that have opportunity to create customer value	• Align offerings to customer needs, preferences, and values; build a delightful customer experience

2.3. Strategic Approach

PGE will advance the intelligent and integrated operation of our grid by leveraging technologies that deliver customer value and system benefits in a changing landscape. This 3-staged iterative approach will enable PGE to build an integrated grid that delivers values to all customers:

- **Model & Monitor (Plan Ahead):**
  Leverage customer trends, grid data, policies, and modeling, to plan ahead by identifying potential pilots, demonstrations and programs. By understanding our system, customers, and industry trends, we can effectively plan and prioritize our research and development efforts.
- **Engage (Successfully Pilot):**
  Incorporate customer and stakeholder feedback as we start small in our deployment and testing of new technologies and programs. By being collaborative and proactive, we can develop pilots such that we can have meaningful, foundational learnings and deploy effective & valuable full-scale programs.

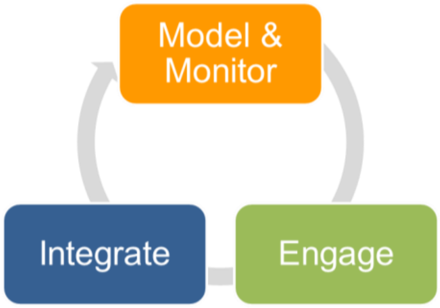


Figure 1: Smart Grid Strategic Approach

- **Integrate (Moving to Scale):**
  Build upon our foundation as we move to scale on proven technologies that drive new customer value. Be a utility that is proactive, nimble, and flexible.

As illustrated above, this is an iterative process—our programs and pilots will inform how we plan and prepare for the future. We anticipate this process is proactive and collaborative with the OPUC and other external stakeholders. We expect an on-going dialogue will allow us to evaluate and realize value from new and emerging technologies quickly. Our efforts will be information-driven and evolutionary (not revolutionary).

2.4. Roadmap

At public meetings on March 15, 2016 and October 20, 2016, PGE shared a 5-year smart grid road map into three initiative categories: Foundational, Grid Optimization, and Customer Engagement. The categories correspond to how initiatives have been outlined in this report.

The roadmap on the following pages includes our best estimate for when pilots and use cases will evolve at PGE over the 5-year time frame. This year's roadmap includes the addition of a column to illustrate anticipated benefits which relate to the OPUC's Policy Goals and Objectives (outlined in Section 1.1).

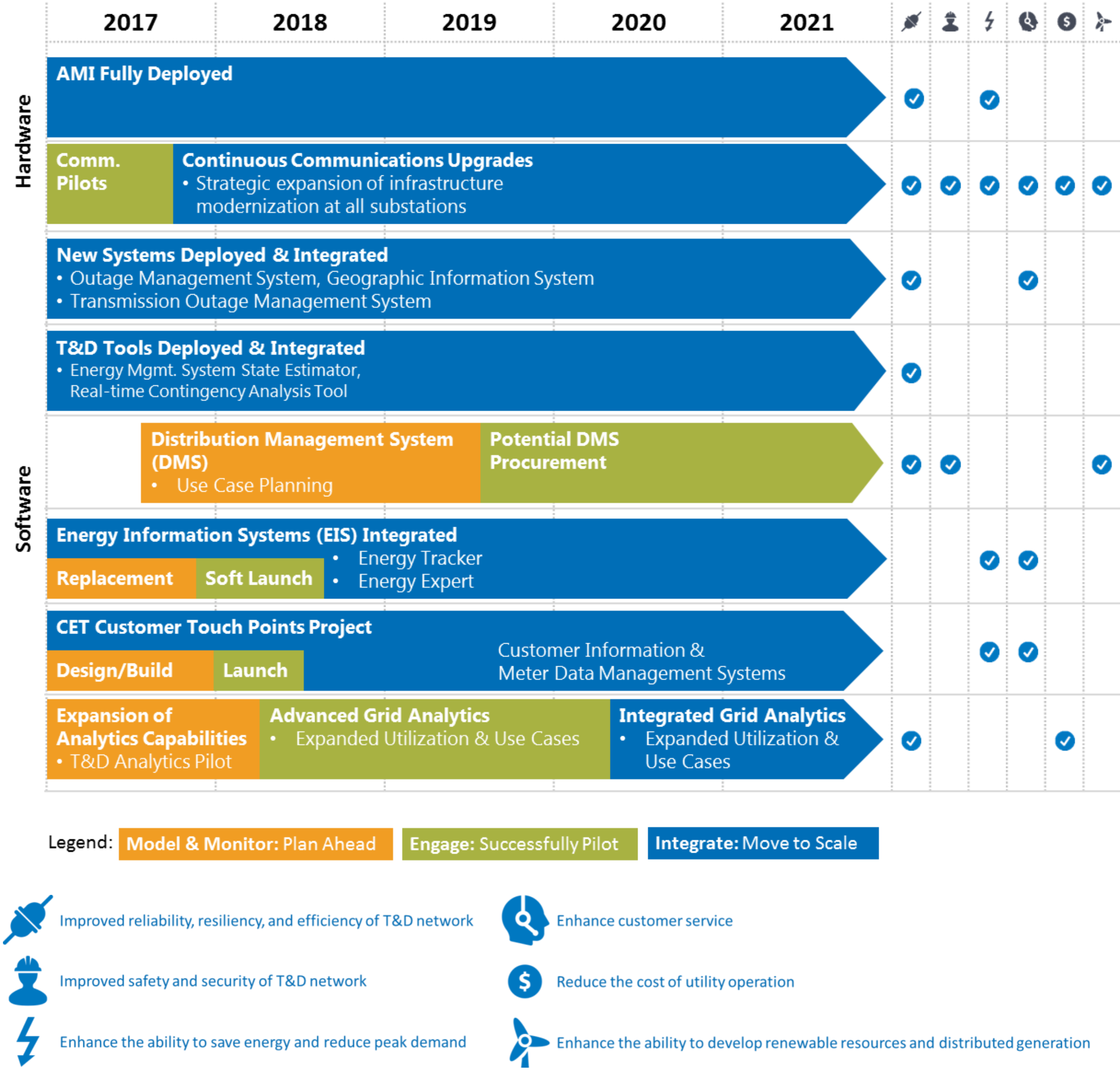
In addition to emerging pilots and programs, it is important to be mindful of expected changes coming to our system. Over the next 5-years, PGE anticipates substantial growth of distributed solar, demand response, electric vehicles, central wind generation, and energy storage:

Table 8: DER and Renewables Five Year Projections

Attribute	Current	5-Year Projections	Growth Factor	Source
Customer Owned PV (MW_{DC})	75.5	186.8	2.5	DG potential Study
Demand Response (MW)	18.7	77	4.1	2016 IRP
Electric Vehicles (Est. Quantity)	10,430	67,272	6.4	2016 Transportation Electrification Plan
Wind Generation (MW)	717	1,232	1.7	2016 IRP
Energy Storage (MWh)	1.25	40	32	HB 2193

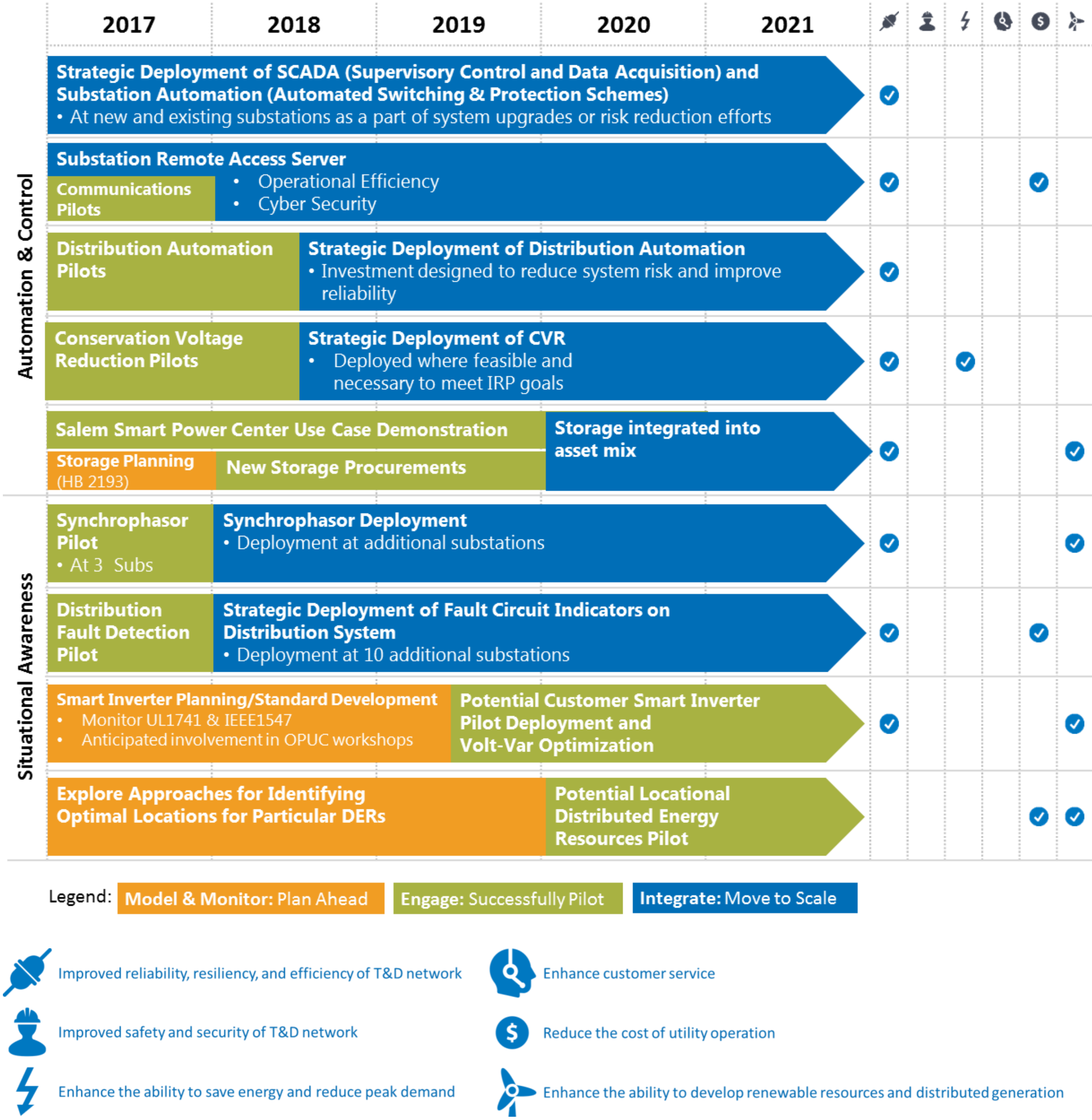
2.4(a) Foundational Initiatives

Hardware and software that enable deployment of smart grid initiatives, allow customers to realize maximum value of smart grid initiatives, and improve system cybersecurity.



2.4(b) Grid Optimization

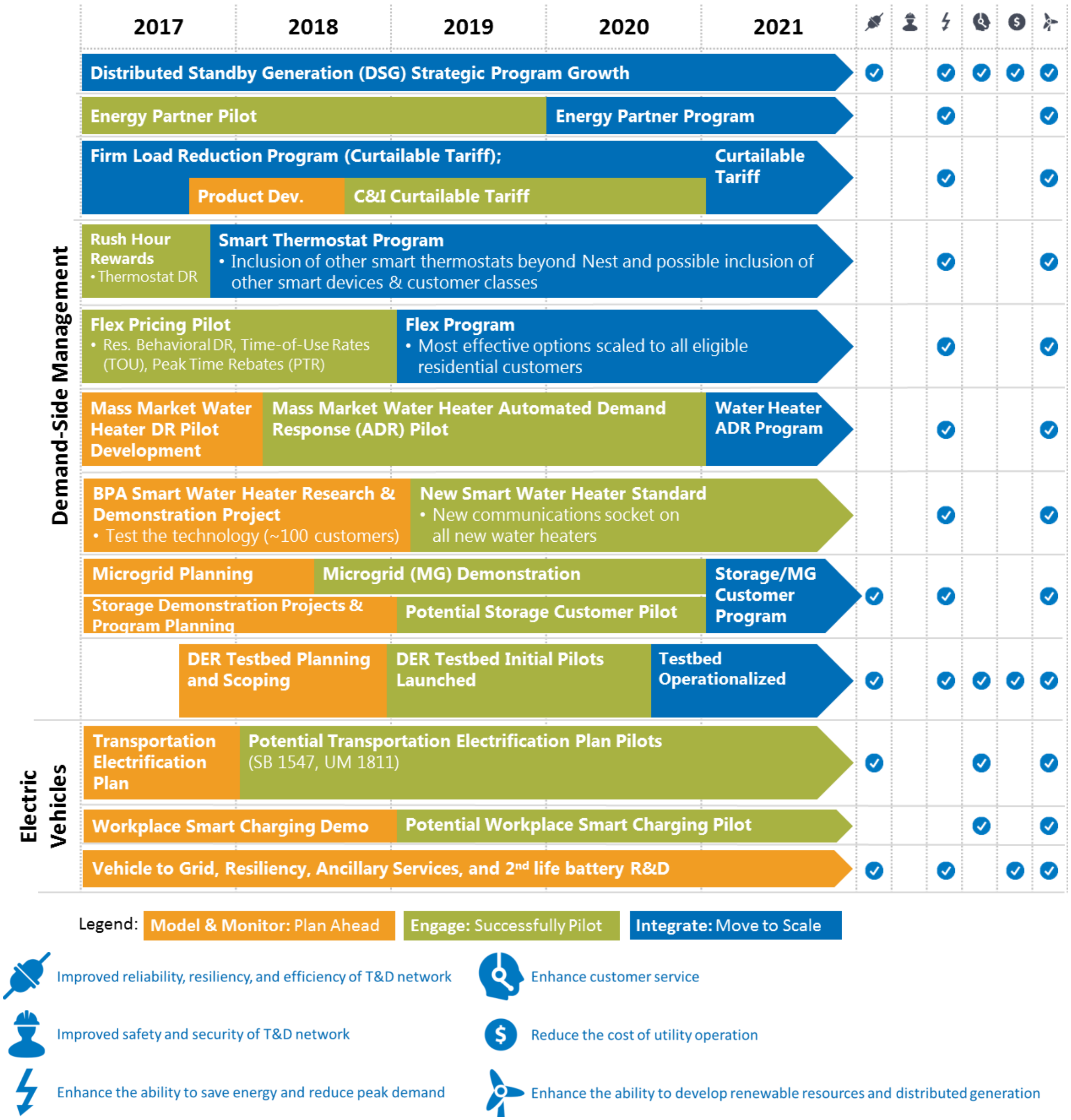
System hardware and tools that automate processes and improve situational awareness to reduce system risk and improve reliability of the transmission & distribution networks by: improving restoration time, avoiding outages, and informing investment & design.



2.4(c) Customer Engagement

Programs and rates that save customers money by:

- Enhancing the ability to integrate renewable resources and distributed generation
- Promoting wise and efficient use of energy
- Increasing capacity utilization on existing assets
- Enabling integration of smart devices
- Improving reliability of electric service



2.5. Alignment with Integrated Resource Plan (IRP)

In the decades ahead, the Smart Grid will facilitate PGE's efforts to interconnect increasing amounts of variable renewable resources to our system. System operators will also be able to leverage demand-side resources and a more dynamic grid to help balance an increasingly variable power supply. This evolution, in conjunction with increased efficiency of the transmission system and PGE's participation in the Energy Imbalance Market will optimize the use of all resources to provide a flexible, reliable, and cleaner system. PGE includes Smart Grid technologies as viable resources in the IRP as they mature, similar to the way cost-effective energy efficiency and demand response are considered. As such, many of our Smart Grid initiatives will continue to be part of a continued two-way conversation between program/system planners and the IRP team and will be included in PGE's IRP process.

Table 9: Smart Grid Studies to Inform IRP

Report Name
Conservation Voltage Reduction Pilot Cost-Benefit Analysis
Demand Response Potential Study
Demand Cost-Effectiveness White Paper
Energy Partner Evaluation
Non-solar Distributed Generation Market Research
Solar Generation Market Research

Table 10: IRP Public Meetings discussing Smart Grid

Date	IRP Meeting
7/16/15	Distributed Generation
8/13/15	Demand Response
9/25/15	Conservation Voltage Reduction
9/25/15	Dispatchable Standby Generation
12/17/15	Smart Grid Status
12/17/15	Energy Storage
12/17/15	Demand Response
8/17/16	Energy Storage Evaluation
11/16/16	Smart Grid Report

2.6. Staff

Over the past three years, PGE has expanded its internal expertise and resources allocated to working on smart grid strategy and deployment. In addition to the many staff supporting smart grid efforts, these positions are dedicated to smart grid-related activities:

- Strategic Asset Management Smart Grid Data Analytics Engineer
- Smart Grid Data Analyst
- Emerging Technologies Project Engineer
- Smart Grid Strategy and Projects Project Manager
- T&D Smart Grid Planning Engineer

2.7. Future of Smart Grid Report

2.7(a) Public Engagement

PGE along with Pacific Power, Idaho Power, ETO, and ODOE attended a staff-led workshop on May 15, 2017 with the purpose of discussing the future of the Smart Grid Report Guidelines. PGE appreciates Staff leading this workshop and providing the opportunity to discuss with Staff and stakeholders the future of the Smart Grid Report. At the workshop we heard:

- Most stakeholders agreed that a 2-3 reporting cycle would be more valuable than the current 1-year reporting cycle. We believe that a report date that follows approximately 12 months after IRP acknowledgement would be appropriate.
- Stakeholders use the smart grid reports as a reference, a central repository to track many different efforts, a tool used to inform agency planning, and a guide for potential vendors to identify upcoming opportunities.
- Stakeholders agreed that the stakeholder and commission engagement process is valuable.

PGE views the Smart Grid Report as the appropriate vehicle for holistically discussing the development of additional DERs in PGE's service area. PGE sees value in using the Smart Grid Report as the central hub for consolidating the work that is occurring in various dockets and proceedings at the OPUC focused on DERs along with planning for how DERs may be deployed in future customer pilots, programs, and grid investments.

2.7(b) Distribution Resource Planning

As a condition of PGE's 2016 Smart Grid Report, the OPUC requested that "PGE identify and discuss the system and Company resources necessary to begin evaluation of DER value to customers and the additional resources needed to commence distribution resource planning."

PGE interprets Staff's reference to "Distribution Resource Planning" to mean a process for identifying locational barriers and opportunities to DER deployment, consistent with what was defined by the California legislature. The California legislature required the utilities in the state to submit to their PUC distribution resource plans "to identify optimal locations for the deployment of distributed resources".[1] Under the law, such plans must "evaluate locational benefits and costs of distributed resources located on the distribution system." The plans must also identify additional utility spending required to facilitate integration of cost-effective DERs, identify barriers to the deployment of DERs, and propose or identify different mechanisms, including pilot programs, for increased deployment of distributed resources.[5]

In short, the DRPs in California today have two overarching goals. First, identify any barriers to interconnection of DERs that customers want to deploy. For example, are there areas that cannot accommodate additional distributed generation absent upgrades to the distribution system? Second, identify any locations on the grid that may particularly benefit from DER deployments. For example, is there a substation or feeder where a transformer replacement could be cost-effectively deferred through the deployment of energy storage or demand response?

It is worth noting that for PGE's system (though no formal hosting capacity has been completed), the answer to the first question is that we anticipate that most feeders on the system could accommodate additional customer-owned generation without significant upgrade to the distribution system. The second question is much more challenging to answer. Dr. Susan Tierney -- former assistant secretary of the Department of Energy and past Chair of the Massachusetts PUC – notes that "Studies indicate the Value of DER to Distribution is typically small relative to the Value of DER to Generation, Transmission or Society".[6]

It is also worth noting that PGE has a number of processes in place to ensure proper distribution system planning for high reliability at a low cost. As discussed in Section 2.5 above, PGE has an integrated resource planning team to evaluate future energy resource needs through a holistic proactive approach. The IRP process evaluates all resources on a consistent and comparable basis, considers risk and uncertainty, and results in an action plan that provides the opportunity for selection of a portfolio of resources with the best combination of expected costs and risks for the utility and its customers. Additionally, PGE has a Distribution Planning Department that utilizes advanced development methodologies and expert engineering staff to perform the following responsibilities:

- Disaggregating forecasted load growth to a substation and feeder-level
- Identifying system constrains & developing capital improvement projects to address risk & reliability concerns facing the distribution system

[1] The CA legislature specifically tasked the utilities with developing DRPs – after previously passing legislation that prioritized DERs in the power system. Similarly, the REV in NY resulted from direct intervention from the governor.

- Maintaining a minimum reliability standard of N-1 redundancy[2] for all distribution feeders
- Performing needs assessments for approximately 650 Feeders, 150 substations, and other distribution assets
- Creating a list of infrastructure projects to mitigate risk and maintain (or increase) reliability on system
- Prioritizing infrastructure project options
- Contributing to locational value assessments for emerging technologies
- Performing regional system studies and risk-based cost benefit analysis to optimize Smart Grid infrastructure investments

The following table summarizes departmental planning functions:

Table 11: Departmental Planning Functions

	Needs Assessment	Resource Assessment	Build
Integrated Resource Planning	Evaluate customers' future needs through proactive, near and long-term forecasting using fundamentals analysis.	Evaluate resource options, including DER, through portfolio analysis to balance cost and risk while maintaining compliance, reliability, and affordability. DER evaluated include: • Energy Efficiency • Demand Response • Energy Storage • Dispatchable Standby Generation • Conservation Voltage Reduction • Others as identified	Acquisition of resources providing essential electric services as identified in the Action Plan.
Distribution Planning	Determine capacity constraints and areas of risk on the system: • Short-Medium-term (5-20 year) feeder-level load forecast • System models • Integrated planning tools	Evaluate infrastructure projects to meet the system and customer need. Currently DERs are not included this process, however, tools to do so are being developed through our energy storage planning process. Though in their infancy, our energy storage evaluation tools are considered nation-leading by many industry experts.	Infrastructure projects are selected and implemented based on reliability, cost, risk reduction, and other system implications.

[2] N-1 redundancy references system ability to provide alternate sourcing for a single deviation from normal conditions, attributable to the failure of one system component.

Creating a Distribution Resource Plan ("DRP") that identifies how and where DERs may be able to improve the reliability, affordability, and sustainability of PGE's electric service is a challenging undertaking. In evaluating resources to commence development of a DRP, it is important to be mindful of the state of distribution resource planning in the industry. DRP is a relatively immature concept with initiation efforts occurring in California (through Proceeding R.14-08-013) and the Northeast through REV proceedings (ex. Matter 15-00733).[7,8] Though the industry is still developing what many of these tools are/will be, PGE is leading the way with nationally recognized tools for energy storage (as acclaimed by Energy Storage Association, PNNL, NREL, EEI, etc.). Best practices and modeling tools are, in many cases, under development or non-existent. The electric industry will need to develop new tools to model the distribution system in more complex ways to determine if there are site-specific capacity and locational values for DERs. As we consider the best path forward for PGE and our customers, we should remain mindful of the current state of industry and balance the interest of being early to adopt best practices with the risk of uncertainty and cost for potentially limited value, given the relatively low cost of power for PGE customers today and the relatively low penetration of DERs on our system.

PGE believes a DRP would likely include the following elements:

1. **Identify constraints to DER within the distribution system** (Feeder Hosting Capacity Analysis): for each feeder on the system, estimate the amount of DERs that can be accommodated (hosted) on the feeder with minimal negative impact (decreased reliability or power quality) to the distribution system. In order to be able to do this analysis effectively, we must first model all existing DERs on the system and incorporate AMI-specific load into distribution system models. Though still in its infancy, PGE is currently evaluating EPRI's Distribution Resource Integration and Value Estimation (DRIVE) tool, a new module in Cyme (PGE's primary distribution analysis tool), for this analysis. In our evaluation, a hosting capacity study will be performed on a selection of five feeders to determine the amount of inverter based generation that can be placed on the specific distribution feeder without system upgrades before adverse impacts occur. The study will examine multiple aspects of the feeder, including overvoltage, voltage deviations, equipment thermal limits, and overcurrent protection impacts for the feeders as increasing levels of generation are added at different locations on the feeder. The output of this type of analysis is a range of capacity that could be accommodated without system upgrades (e.g. 500-kW to 2-MW). Any DER less than 500-kW could be added to the feeder; any DER 500-kW to 2-MW would require further review; and any DER larger than 2-MW would likely not be able to interconnect without costly system upgrades. Ultimately we anticipate integrating this type of analysis into all T&D planning engineer's core responsibilities; we need at least 1 additional FTE to accommodate the additional workload. This work would be performed annually and when there are major system changes to ensure analysis is up-to-date.

2. **Determine where and when DERs are most beneficial to the system** (Locational Net Benefits Analysis): would evaluate DERs' benefits at specific locations and times, which would allow for DERs to be deployed at optimal locations, times, and quantities so that their benefits to the grid are maximized and customer costs are minimized. As discussed in Section 7.5, PGE uses a number of means to quantify *system-level* benefits (and cost-effectiveness) of DERs to plan and

evaluate deployments today. The industry, however, lacks best practices today for evaluating locational net benefits of DERs as an additional value stream. As discussed at a public workshop on April 28, 2017, this remains a cross-cutting issue across all DER cost-effectiveness analyses:

- For energy efficiency, the Energy Trust currently uses an average T&D capacity savings as a benefit stream.
- In the Resource Value of Solar docket, we factor system-average discounts to T&D line losses depending on whether the system is installed on customer site, distribution system, or transmission system.
- For potential Energy Storage deployment PGE is evaluating site-specific asset deferral benefits.
- For DR, PGE applies distribution charge from Schedule 7.
- For Transportation Electrification PGE has not included T&D avoided costs.

Identifying full locational net benefits of DERs on PGE's system would require the development of new tools. Even in states with more resources and significantly greater deployment of and legal/policy support for DERs, the tools do not currently exist to effectively identify all locational benefits. The cost for development of such tools is difficult to estimate, given the uncertainty associated with them. PGE is currently developing tools through our energy storage planning process (UM 1751) that aim to identify locational benefits associated with siting energy storage. Rather than estimating a cost for this work, we propose to continue utilizing existing staff to engage in on-going stakeholder dialogues and pilots to better understand the nuances and challenges of locational benefits.

3. **Forecast and plan feeder-level deployments of DERs**: in order to realize meaningful value from hosting capacities and net benefit analyses, PGE will need to begin forecasting DER proliferation on a feeder-level. Today, most forecasting efforts are system-level in nature, and in some cases do not fully reflect DER penetrations. One such example is net-metering customers and our long-term load forecasts. We do not have generation data for small solar arrays that are net metered, only a net load at the point of service. In other words, customers with solar simply appear as customers with lower than average demand, rather than a separately metered plant. In order to model DER impacts into the future, we must estimate and project system outputs on all feeders. Efforts are already underway to disaggregate/estimate solar's "negative load" from the premises' net load. Due to the additional modeling and granularity required, we estimate this could be accommodated with an additional 1 FTE on our forecasting or distribution planning team.

4. **Develop a T&D Operations Roadmap:** to realize many of the potential value streams we anticipate being identified in any DRP would ultimately require real-time situational awareness and control of DERs across the distribution system. Today, PGE's distribution operation teams and processes reflect a traditional generation->transmission->distribution->customer energy flow. To optimize deployed DERs, we will likely need new systems (i.e. Distribution Management System), new facilities (i.e. Distribution Operations Center), and new skills. PGE is currently working on developing a T&D roadmap which will outline when/what drivers will trigger deployments of these types of changes to distribution operations. The roadmap will be

developed with existing PGE resources. Operationalizing that plan, however, will likely incur significant costs that we have not yet quantified. We estimate near term costs at $300,000 which would likely include a combination of PGE and contract labor.

5. **Pilot innovative solutions and models:** in order to test the effectiveness of new models, tools, and processes, a DRP must include pilots and demonstration projects. Though no resources will be required to commence distribution resource planning, we anticipate that DRPs in Oregon would, like they have in other jurisdictions, include proposals for pilot projects that range from $250,000 to $5,000,000. Some examples of pilots included in DRPs of California and New York utilities:

    a. Demonstration of dynamic integration capacity analysis: utilize dynamic modeling techniques through power system modeling software to demonstrate dynamic integration capacity analysis on a single feeder.
    b. Demonstration of the Optimal Location Benefit Analysis Methodology: SCE will identify two distribution infrastructure projects in the region to calculate a deferral value to determine "avoided cost". SCE will deploy a DER portfolio at the sites to defer the two projects. [9]
    c. Con Edison's Brooklyn Queens Demand Management Program which aims to defer a $1.2B substation upgrade through non-wire alternatives, including 41 MW of customer-sided solutions and 11 MW of non-traditional utility sided solutions.[10,11]

6. **Engage in a Public/Regulatory Process:** Much like the smart grid report or transportation electrification plan, we anticipate that filing a DRP will require multiple touch points with the OPUC, staff, and stakeholders. As such, we estimate 0.5 FTE of incremental resources needed to backfill the workload of internal resources impacted by this effort. This could grow considerably depending on the scale and scope of a DRP stakeholder process.

7. **Report Preparation:** for a first DRP, PGE estimates report planning, writing, and assembly will require an additional 0.5 FTE.

An initial deployment of a DRP will likely just be a stepping stone. Outputs will help us learn and inform better practices going forward. We may realize that in order to get truly meaningful value out of our hosting capacity analysis that we must add more staff or deploy new systems, etc. Table 12, below, summarizes the estimated resources to being distribution resource planning – these estimates are preliminary and will likely change as our understanding of our needs continues to grow.

Table 12: Estimated Resources Needed to Begin Distribution Resource Planning

Task	Estimated Resources Needed	
	FTE	Fully-Loaded Costs ($)
Feeder Hosting Capacity Analysis	1	$ 183,000
Locational Net Benefits Analysis	-*	-
Feeder-Level DER Forecasts & Planning	1	$ 183,000
Distribution Resource Plan Roadmap & Implementation	2	$ 300,000
Modelling Tools	TBD (as Market Matures)	
Pilots	-*	-
Public/Regulatory Process	0.50	$ 92,000
Report Preparation	0.50	$ 92,000
	Total	$ 850,000

**Task does not require additional resources at the current time but is likely to incur costs at a later date based on outcome of a DRP process, scale of DRP process, etc.*

As indicated in this Section, PGE has a number of efforts in-flight that better position us to realize maximum value from a DRP for our customers (e.g. forecasting system loads & identifying future system constrains, developing locational benefit modelling tools for DERs, demonstrating hosting capacity studies, and developing a long-term distribution operations roadmap). There is work to be done, but given the pace of change in this space we believe our approach and pace are sensible and in customers' best interest. We look forward to presenting progress of these efforts to the Commission in our workshop this fall.

Section 3. Status of Current Smart Grid Initiatives

3.1. Foundational Initiatives

3.1(a) Hardware

Advanced Metering Infrastructure (AMI) Deployment

Approved by OPUC Order No. 08-245, PGE installed digital Smart Meters at over 825,000 customer locations along with dozens of communication towers.

Status: Complete

Communications Upgrades

PGE is upgrading fiber and wireless communications networks to enable 2-way communications to the constantly evolving network of intelligent electronic devices (IEDs) and the data they create.

Communications Wireless Upgrades

PGE procured a 220 MHz block of radio spectrum, with the primary purpose of replacing the land-mobile radio system to increase reliability and safety. Additionally, PGE procured 700 MHz spectrum to serve a variety of data requirements including but not limited to: distribution automation, demand management programs, conservation voltage reduction, SCADA, synchrophasors, and customer "smart" devices. Enhanced communication networks are fundamental to a fully functioning smart grid—upgrades enable device monitoring, control, and remote asset management.

Status: Active Deployment

Next steps: PGE will construct necessary base stations to ensure system-wide connectivity for the radio spectrum in 2017 with intent to go live in 2018.

Communications Network Upgrades

92 of PGE's substations are connected to SCADA via 2W/4W copper lines leased from telecommunications companies. The telecommunication industry will phase out service to all 2W/4W lines by 2020; as such, PGE is upgrading communication infrastructure to those substations by 2020. To accomplish this, PGE is moving away from point-to-point circuits and installing a private Transport Services network. Long term, this will enable high speed Ethernet which would enable real-time monitoring of thousands of data points at each substation. Substations will also connect to the radio spectrum as a backup path for redundancy.

Status: Active Deployment

Next Steps: PGE will be installing the core infrastructure in 2017 and deploying the network at high priority stations with 2W/4W connections. Further deployment will continue into 2018 and beyond.

3.1(b) Systems and Software

Energy Management System (EMS) & Automated Generation Control (AGC)

PGE has deployed a modern Energy Management System (EMS) and Automated Generation Control (AGC) for our generation and transmission systems. These tools allow for centralized control of distributed resources and advanced analytics on historic data to optimize system performance.

Status: Complete

Energy Management System (EMS) State Estimator (SE)

To optimize the operation and reliability of the transmission system, PGE has developed a system model for an EMS SE. The model reads system data from the SCADA system (voltage, line flows, etc.) and performs power flow simulations to give insight into the state of the grid. The SE is currently used as one of a handful of tools for the transmission operations engineering team to better coordinate with Peak Reliability on operating concerns.

Status: Limited Deployment

Next steps: Advanced tuning of the EMS SE is underway and a second phase of SE should be deployed in Q4, 2016.

Real-time Contingency Analysis (RTCA)

RTCA is a situational awareness tool that runs contingency on the SE. The model runs power flow for defined contingency scenarios (loss of line, transformer, or any other element in the system). The model then ranks the overall impact of potential system operating limit concerns (thermal overloads, voltage issues). This enables pre-contingency mitigation strategies to be employed to address the potential impact of a particular outage scenario. Contingency models for 230kV and 115kV lines were integrated in 2015.

Status: Limited Deployment

Next steps: PGE is developing contingency models for 57kV lines and will integrate RTCA in T&D operations in summer, 2017.

Outage Management System (OMS)

The new OMS, deployed in 2015, uses input from AMI, SCADA, and customer calls to identify interrupted circuits and model the extent of an outage. The new system provides faster, more accurate information to help prioritize restoration efforts and optimize field crew deployment. Logic within the OMS allows outage managers to selectively ping meters, or groups of meters, to confirm outages and outage restoration as well as filter out unwanted alarms and limit the number of alarms for the OMS to analyze.

Status: Complete

Geographical Information System (GIS)

A modern GIS can provide an accurate, as-built view of all components of the electrical grid and brings data together for improved field operations, customer service and analysis. ESRI ArcGIS provides engineers with a wide range of data that can be displayed visually across an integrated set of technology platforms. These data will be useful for integrated outage management, asset management and future distribution management systems. GIS is foundational for realizing many smart grid benefits:

- Advanced control and monitoring of asset network
- Visualization of reliability metrics
- Advanced geospatial analytics
- Large data visualization

Status: Complete

Customer Engagement Transformation (CET): Customer Touchpoints Project

CET is a comprehensive multiyear program which started in 2014. It is comprised of 24 projects focused on operational efficiencies, process improvements, employee development, business strategies, customer strategies, and the replacement of two large customer systems:

- Customer Information System (CIS); and
- Meter Data Management System (MDMS).

In conjunction with replacing these systems, we are taking advantage of opportunities to make improvements such as implementing more efficient billing through automation and improving key business processes that have an impact on customer experience. The additional functionality of the new systems will provide PGE with opportunities to improve the way we engage and serve our customers.

CET will help demand-side management (DSM) programs similarly to how it will help any of our programs: by providing more systematic data tracking, easier setup and configuration of programs, and allowing for a more streamlined process for setting up new rates. DSM will also benefit from more robust and automated VEE for interval data and a more self- service system for access to this data. Additionally the tracking of end user data in the CIS will aid in our targeting of DSM programs. Through better tracking PGE can enhance its marketing efforts by understanding why participants may decline.

Status: Planned Deployment

3.1(c) Data and Analytics

T&D Analytics

PGE has built systems that utilize smart meter data for a variety of T&D operational improvements, such as overloaded transformer analysis which helps identifying opportunities for proactive equipment replacement. These tools help avoid potential feeder downtime and customer outages.

Additionally, PGE has begun an advanced analytics pilot program to leverage the massive amounts of new data available via IEDs on the T&D system. This pilot project is utilizing existing data streams, such as AMI data, to produce actionable information required to enhance planning and operations activities on PGE's T&D system. The system will help PGE develop use cases for leveraging real-time data streams to improve operational efficiencies.

To date, PGE has used the platform to create interactive dashboards, conduct event analyses, and create system alarms for meter diagnostics, network performance, and overloaded transformers.

Status: Pilots & Evaluation

Next steps: In 2017, PGE is working with the software vendor to enhance the voltage data for meters participating in the CVR pilot (to ensure voltage levels stay within ANSI limits) and to enhance the circuit analysis workbench to improve feeder-level situational awareness.

In future years, PGE will continue to evaluate evolving best practices and will utilize the analytics platform to perform circuit analysis; feeder-level insights utilizing aggregated AMI data will help inform asset management initiatives.

Anticipated results include improved service restoration times, increased system modeling accuracy and capabilities, and enhanced asset replacement and maintenance strategies.

Energy Tracker

Energy Tracker is an energy information platform that provides residential and general business (Schedules 7, 32, 38, and 83) customers access to their AMI data through their accounts on PortlandGeneral.com. The tool provides:

- Monthly, daily, hourly, and interval (i.e. 15-min) energy use charts
- Export of energy usage data to Excel or apps via the Green Button
- Billing insights that compare one billing period to another
- Savings tips, goals, forecasts and tailored recommendations
- Direct links to ETO incentives for energy efficiency measures
- Text/e-mail alerts

PGE is able to make strides toward its energy efficiency targets by actively engaging customers in the wise and efficient use of energy. This information has empowered more than 230,000 customers to control their electricity bills by helping them understand when and how they are using electricity. Energy

Tracker customers have reduced their annual energy consumption 3% faster (332 kWh) than non-Energy Tracker customers.

To help ensure that PGE's low-income customers are aware of the Energy Tracker tool, PGE has provided information and demonstrations to the Community Action Agencies (CAAs) that serve our customers at our semi-annual meetings. At the request of its staff members, one of the agencies incorporated Energy Tracker into a new program it offered during winter 2013/2014. In addition, the Company offered to demonstrate the tool during the CAAs' energy education workshops with clients and to train the low-income weatherization auditors on the tool, so that they could walk through the information with a customer during the course of an audit.

Status: Active Deployment

Next steps: We have recently partnered with Opower to do a refresh on the Energy Tracker system to improve the customer experience. The new system, which is slated to go live with our CIS/MDMS replacement in Q1 2018, will provide a more engaging customer experience, new user interface, mobile access, and will eventually allow for simplified enrollment in TOU, DR, and other customer programs. The new platform will provide different displays and energy saving tips for residential and commercial customers. Customers on Schedule 85 and 89 will also be able to access Energy Tracker.

Energy Expert

Energy Expert is an advanced energy monitoring platform available to PGE large commercial and industrial customers for a fee. Energy Expert uses 15-minute interval meter data to give customers a highly accurate view of energy consumption over time.

PGE has offered Energy Expert for over 10 years, and the current version of Energy Expert (version 6) has been available since June 2015. Energy Expert features include:

- Display of advanced customer energy information data (consumption, historic trends, load profiles, cost savings opportunities, peak reports)
- Identification of abnormalities or areas for operational improvements
- Consolidation of weather data, time of day, day of week to predict energy usage
- Notifications and alerts
- Comparisons to historical data to track savings associated with energy conservation activities

To help ensure that PGE's business customers are aware of the Energy Expert tool, PGE holds webinars, workshops and onsite demonstrations to help potential users understand the benefits of monitoring daily energy usage. Currently 108 customers are utilizing Energy Expert on over 500 meters.

Table 13: Number of Customers Utilizing Energy Expert by Year

Metric	2012	2013	2014	2015	2016
# Customer Utilizing Energy Expert	40	101	97	105	108

Status: Active Deployment

3.2. Grid Optimization

Grid optimization initiatives are transmission, substation, and distribution systems investments in hardware, software, technologies, and processes that improve system reliability and efficiency, increase flexibility of grid integration, enhance the ability to reduce peak demand, and reduce overall utility operation costs.

3.2(a) Automation and Control

SCADA (Supervisory Control and Data Acquisition)

Deployment of SCADA to substations increases visibility of the grid to T&D operations and reduces the likelihood and durations of outages. Currently 78% of PGE substations are controlled and monitored by SCADA. The primary focus in 2016 was upgrading aging SCADA systems, installing SCADA on mobile substations, and planning for deployment to additional distribution substations. PGE is also strategically adding SCADA to reclosers and other intelligent electronic devices (IEDs) that will increase the visibility of the grid to T&D operators.

Status: Active Deployment

Next steps: PGE anticipates SCADA deployment at an additional 2-3 substations and replacing multiple aging systems in 2017. Multiple distribution stations will be outfitted with SCADA over the next five years as they are rebuilt to address aging assets. PGE is developing a plan for deploying SCADA to the remaining electronic reclosers and updating the standard recloser installation process to ensure all new devices are installed with SCADA.

Substation Remote Access Server

In 2014, PGE activated a substation remote access server which allows remote visibility to IEDs which speeds up restoration time and saves on operation & maintenance costs. Additionally, it provides access to data related to asset monitoring, disturbance monitoring, and real-time operations. Currently, 26% of substations and plants, plus our two control centers, are connected to the Substation Remote Access Server.

Status: Active Deployment

Next steps: PGE anticipates continued deployment of substation remote access server at new substations and on existing stations as a part of regular upgrades.

Substation Automation

Expansion of SCADA and IEDs such as microprocessor relays are allowing increased levels of automation at substations. These efforts provide faster isolation of faults and improve system reliability.

- **Distribution Automation**: distribution substations and feeders automatically attempt to restore power after outages
- **Automated control schemes**: enables automatic transfer to alternative transmission source in the event of a transmission outage

Status: Active Deployment

Next steps: PGE anticipates continued deployment of substation automation at new substations and on existing stations as a part of regular upgrades. PGE is also actively scoping Distribution Automation projects.

Energy Storage

House Bill (HB) 2193 mandates that PGE procure at least 5 MWh of new energy storage by January 1, 2020. PGE has created an inter-departmental team responsible for developing a plan for meeting this mandate. The team has developed a project vision which is to optimize PGE’s opportunities to learn about contracting for and operating different applications of energy storage by creating a diversified storage portfolio (in location and storage type). Key principles include utilizing storage as an integration resource, providing system benefit to all customers, balancing cost & risk while maximizing reliability, integrating T&D with Power Ops, and enabling resource diversification/de-carbonization. The team has identified three types of projects to deliver on the above vision and key principles:

- **Substation**: A 10-20 MW, PGE-owned, operated, and controlled battery project that connects to the distribution system and interconnects directly with Power Ops.
- **Mid-feeder**: One or more ≤5 MW PGE-owned, operated, and controlled batteries that provide added resilience to more than one customer. Potentially combined with distributed generation. (Could be in the right-of-way, at an existing PGE facility or customer site.)
- **Customer Programs**: PGE-controlled and customer-controlled (with Demand Response) battery projects that examine potential customer program offerings.

Status: Planning

Next Steps: PGE is evaluating options over the next 2 years with the intent to begin procurement in 2018 and system integration around 2020.

Distribution Automation (DA)

Description: DA refers to a distribution system that has the ability to automatically locate and isolate faulted feeder sections, and subsequently restore service to un-faulted feeder segments. DA systems are capable of automatically isolating faulted line segments and restoring power to other customers on the feeder within minutes. In the past, those customers were sometimes out for several hours. The DA system can be monitored and controlled via SCADA.

PGE deployed a DA pilot at Gales Creek in 2012. DA has resulted in operational savings and System Average Interruption Duration Index (SAIDI) reductions for customers served by the Gales Creek system:

Table 14: Gales Creek Reliability Metrics, 2006-2016[12]

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016
SAIFI	3.4	5	4.1	2.6	3.9	0.6	1.7	0.9	1.4
SAIDI (min)	1,115	1,134	1,278	448	695	116	252	184	393
# of Outages	45	59	41	41	51	21	37	43	31

Status: Pilots & Evaluation

Next steps: PGE is evaluating technologies deployed in the DA pilots and is developing a strategic plan and standard specification for future DA deployment. PGE expects a formal plan to be developed in 2016-2017. PGE plans to utilize its asset management tools to inform when and where to deploy DA. PGE is evaluating the potential installation of DA on two feeders in 2016 but expects future strategic deployment of DA to begin in 2018.

Conservation Voltage Reduction (CVR)

CVR is the strategic reduction of feeder voltage, deployed with phase balancing and distributed voltage-regulating devices to ensure end-customer voltage is within the low range of ANSI (American National Standards Institute) acceptable voltages (114V – 120V). PGE completed feasibility studies and two CVR pilot projects in 2014 at Hogan South substation in Beaverton and Denny substation in Gresham. By reducing voltage 1.5% - 2.5% in the pilot project, PGE was able to reduce customer demand (MW) and energy consumption (MWh) by 1.4% - 2.5%. The pilots yielded customer energy savings of 768 MWh in 2014. A preliminary evaluation has identified 94 transformers as potential CVR candidates with a customer energy savings potential of 142,934 MWh/yr. (16 MWa).

Status: Pilots & Evaluation

PGE is focusing CVR efforts in 2016-2017 on piloting communications networks and technology platforms to monitor distributed voltage control devices and customer voltage via AMI. Through 2017, PGE is developing advanced analytics to allow engineers to efficiently observe the status of CVR implementation. This will yield increased observability and customer-level alarms for instances of voltage levels outside of ANSI voltage limits. With a proper communications network and analytics to effectively deploy CVR, PGE anticipates a strategic deployment of CVR starting in 2018.

3.2(b) Situational Awareness

Fault Detection (Distribution)

A pilot is underway in which Faulted Circuit Indicators (FCIs) have been installed on one feeder. The data created by the FCIs are integrated via AMI communications infrastructure. PGE is monitoring the test case for the FCIs and will evaluate the cost-benefit of the FCI deployment and determine whether or not to invest in FCIs for more feeders along with necessary server upgrades. The Company anticipates the pilot should result in improved reliability metrics.

Status: Pilots & Evaluation

Next steps: If this single feeder pilot does not provide sufficient data and resources become available, FCIs will be installed on four additional feeders. If the pilot is successful, a strategic deployment of FCI infrastructure could occur starting in 2018.

Synchrophasors on Transmission System

Synchrophasors provide enhanced system situational awareness for transmission operators and planners by providing real-time system information. Phasor measurement units (PMUs) capture data at a higher resolution than typical grid monitoring devices and include more depth of information beyond voltage and frequency, including GPS, and time stamped phasor quantities. A wide deployment of PMUs and phasor data concentrators (PDCs: IEDs that collect and aggregate data from PMUs), communications infrastructure, and analytics software can lead to:

- Enhanced situational awareness
- Improved visibility into interconnection points with adjacent utilities and regional flowgates[3]
- Detailed post-event analysis
- Generation model validation and test avoidance (reduced down time of generation facilities)
- System state model validation

PGE is strategically deploying PMUs and PDCs at critical transmission facilities to realize these benefits. To date, PGE has deployed synchrophasor technology at 1 transmission substation (Rosemont). In addition to PMU and PDC installation in the field, PGE has invested in critical server infrastructure and software that will enable the Company to realize the maximum benefits of this technology.

Status: Pilots & Evaluation

Next steps: Final network server installation is scheduled for the fourth quarter of 2016. Deployment of synchrophasor technology is scheduled for 12 additional substations over the next few years.

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[3] PGE is evaluating participation in WISP (Western Interconnection Synchrophasor Program) which works to increase grid operators' visibility into bulk power system conditions, allow earlier detection of grid stability threats, and facilitate PMU data transfer with neighboring control areas: https://www.smartgrid.gov/project/western_electricity_coordinating_council_western_interconnection_synchrophasor_program

Remedial Action Schemes (RAS)/Special Protection Scheme (SPS)

Description: A RAS is an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability.[13] PGE has established RAS at Grand Ronde and Round Butte. These schemes leverage the EMS SE & RTCA to help PGE maximize its T&D infrastructure and defer capital investments.

Status: Limited Deployment

Next steps: Evaluate needs for additional RAS as required to address Transmission constraints.

Distribution Temperature Sensing (DTS)

PGE has installed real-time line sensors on six network feeders in the Company's service territory. These linear sensors give visibility to temperatures of subterranean cables at 2 second intervals. Because temperature affects capacity, insight into the temperature better informs PGE of the timing and need for future system upgrades. DTS also allows PGE to recognize unusual hot spots which could indicate a pending cable failure.

Status: Limited Deployment

Next steps: PGE is including DTS in designs for a new substation expected to go into service in 2018-2019.

Voltage Disturbance Detection (i-Grid)

Voltage disturbances (including sags, swells, interruptions, and outages) are the most common power quality problems. PGE has installed i-Grid detection devices that capture and record voltage disturbances, as well as long-term voltage trends. Voltage reporting allows engineers to perform post-event analysis and diagnose system issues which could result in proactive equipment replacement. To date, PGE has installed 112 i-Grid detection devices on 107 feeders.

Status: Limited Deployment

Next steps: PGE will continue limited, strategic deployment of voltage disturbance detection devices. Additionally, PGE will evaluate additional ways how to leverage voltage reports such as enhancing asset monitoring capabilities.

Travelling Wave Fault Location Protective Relays

PGE has completed the installation of Travelling Wave Fault Location Protective Relays on the Bethel-Round Butte (230kV), Shute-Sunset (115kV), and Grassland-Slatt, BPA (500kV) lines. These relays enable greater precision in pinpointing the location of transmission faults, greatly reducing the duration of transmission outages. Historically, the Bethel-Round Butte 230kV line has been PGE's least reliable 230kV circuit. Sustained outages to this circuit averaged three-four days for restoration due to difficulty in locating the faulted section. This technology will enable PGE to accurately locate faulted sections without helicopter dispatch, saving $24,000 per event.

Status: Limited Deployment

Next Steps: Continued deployment at select transmission lines.

T&D Asset Monitoring

By installing IEDs on many large capital assets, PGE is promoting a more reliable grid and increased asset utilization. Dissolved Gas Analyzers (DGAs) monitor dissolved gas in system transformers. Changes in dissolved gas characteristics could indicate a deterioration of device health and imminent asset failure. This type of proactive monitoring allows PGE to practice condition-based maintenance as opposed to time-based maintenance, optimizing Company resources.

PGE has installed advanced transformer sensors to monitor dissolved-gas on 35 of 41 critical transformers. The Company is also installing DGAs on non-critical transformers on a case-by-case basis.

Status: Active Deployment

Next steps: The Company plans to upgrade the remaining critical transformers in 2017. In the next couple of years PGE intends to evaluate installing similar sensors on other system assets such as circuit breakers and substation batteries. Real-time sensor information from `these devices could result in optimized maintenance schedules and prevented device failures and outages.

3.3. Customer Engagement

Customer engagement initiatives are investments in energy information systems, pricing programs, demand response, and system development. These initiatives are intended to enable customers to be active participants in the smart grid, while improving the customer experience, saving energy, and reducing peak demand.

Given capacity needs identified in the IRP, customers will be become an increasingly critical resource to address system needs. We are aggressively pursuing customer capacity resources through a minimum of 77 MW of demand response and pricing by 2021 and are actively looking at ways to push this portfolio even farther. Coupled with over 120 MW of dispatchable standby generation, we expect to have over 200 MW of customer-enabled capacity resources online by 2021. With growing customer awareness and the improving cost-effectiveness of new technologies (particularly energy storage), we expect to see even more growth in this area in the future.

3.3(a) Generation, Storage, and Microgrids

Dispatchable Standby Generation (DSG)

PGE works with large customers that own onsite back-up power generators to provide a reliable, firm capacity resource. PGE maintains and fuels participating generators. PGE has 121.36 MW of capacity from these generators which contribute to the Company's non-spinning reserves.

Status: Active Deployment

Next Steps: The Company has evaluated DSG capacity and planned growth as a part of the 2016 IRP process. As a result, PGE is slowing the growth of the program to maintain alignment with non-spinning reserve requirements.

Fire Station Microgrid

Figure 2: Fire Station 1, SW Ash St.

In 2016, PGE, ETO, and PUC Staff participated in the Rocky Mountain Institute's e-Lab Accelerator program to discuss opportunities for solar plus storage microgrids. Though not a participant in the program, the City of Portland is eager to demonstrate energy storage to support their resiliency efforts, to create a training tool for emergency response, and to reduce facility operating costs. In October, 2016, PGE's Renewable Development Fund awarded the City of Portland a $89,959 grant towards the cost of a solar plus storage single site microgrid at Fire Station #1 in downtown Portland. The City intends to use the funds to install a 30 kW solar array and 30 kW/60-120 kWh battery to create a microgrid at the fire station. PGE is working with the City to scope the project and plan for interconnection. PGE hopes to offer an incentive to the City for control of the battery to call demand response. The City will use the storage for back-up, demand charge optimization, and training.

Status: Planning Demonstration Project

Next Steps: The anticipated construction for the facility is Q3, 2017.

Customer Battery Back-Up System

The project objective is to minimize the cost of adding storage to the grid by combining both utility and customer value propositions. In collaboration with Portland State University (PSU), PGE has advanced their laboratory prototype to a field battery/inverter system (BIS) prototype demonstration in June 2016. The project serves to test end-to-end controls and equipment specifications required to utilize a BIS to provide backup power for an entire home during an outage, but at other times, to serve numerous use case such as a resource to serve peak demand, storing excess wind energy at night, and aiding renewables integration in general. The field prototype is 8kW/30kWh.

Status: Research

Next Steps: In 2017, PGE will install a 2nd customer battery back-up system in 2017. The 2nd system will be sited at an employee’s home who has a net metered solar array. The 15.5-kWh battery will allow the company to test and evaluate a 2nd storage technology as well as a use case with solar integration (to extend customer backup power). This is becoming increasingly important to evaluate as 5-10% of new solar connects are inquiring about storage integration. Though cost-prohibitive for many customers today, we may be able to find utility value that could help reduce costs for integrating customer-sited storage.

If the demonstrations prove successful at simplifying the installation of a BIS “at-the-meter” with cloud based control, then a pilot program may be developed with the long-term goal of creating a program where these systems would serve as a capacity resource and to aid renewables integration.

3.3(b) Pricing

Commercial and Industrial Time-of-Day Pricing (TOD)

PGE offers TOD pricing via Schedules 83, 85, and 89. All customers with monthly demand in excess of 30 kW are on a time-varying pricing program.

Status: Active Deployment

Residential and Small Commercial Time-of-Use Pricing (TOU):

PGE offers a voluntary program to customers with up to 30kW of demand available via Schedules 7 and 32. The program has approximately 2,300 residential customers enrolled. For the past decade, PGE has limited promotion of the program at the direction of the Portfolio Oversight Committee for reasons of cost-effectiveness. It is actively promoted to EV drivers today. The Flex Pricing Research Pilot (see below) is designed to determine the future TOU rate or rates that will replace the existing TOU rate for residential customers and be actively promoted.

Status: Active Deployment

Flex: Pricing Research Pilot

In 2014, PGE began a strategic effort to evaluate pricing program types and barriers to customer participation. PGE completed market research that included surveys and focus groups to help inform a pilot offering. PGE also leveraged AMI data to conduct load segmentation research, identifying 5 load profiles that can be targeted for demand response and pricing initiatives. A pilot to test various pricing program types was approved with deferred accounting on June 15, 2015 (Docket No. UM 1708, Order No. 15-203).[14]

The Flex pricing pilot tests various pricing program types to identify which ones offer the best customer experience and the greatest system benefit:

- Behavioral Demand Response (BDR)
- Day/Night TOU
- Peak-Only TOU
- Three-tier TOU
- Peak Time Rebates (PTR)

Recruitment strategies were shared with stakeholders at the 2/9/16 customer engagement workshop. Recruitment for the pilot began in February, 2016. As of April 2017, PGE had enrolled roughly 8,000 participants (assigning half to treatment and half to control groups). An additional 7,000 were included in opt-out peak time rebate or behavioral demand response programs.

Table 15: Flex Pilot Participation and Progress

Metric	2016
Participants	13,897
Maximum Available Winter Capacity (MW)	1.1
Maximum Available Summer Capacity (MW)	3.5

Status: Pilots and Evaluation

Next Steps: Cadmus is currently conducting a process and impact evaluation of the Flex program. We expect to have an evaluation report on the first program year available for staff in September of 2017.

Based on the final evaluation of the Flex pilot, PGE plans to identify one or more of the most effective pricing program options to scale to a program for all customers in 2019 after the deployment of the new Customer Information and Meter Data Management Systems. We plan to select the program(s) that best balances enrollment, retention, load impacts, cost-effectiveness, and customer satisfaction. We expect this will include at a minimum a time of use rate as well as a dynamic option, such as BDR or PTR.

3.3(c) Demand Response

Firm Load Reduction for Commercial & Industrial Customers

Through the Schedule 77 program, PGE offers demand response (DR) to large non-residential customers who are able to commit to a 4-hour load reduction of at least 200 kW of demand at a single point. This program was launched in 2010. To date, four customers have participated in this program, and historically have demonstrated that load reductions of 18.3 MWs were achieved reliably. These reductions are considered as a resource in our IRP.

Though customers commit to a certain level of curtailable demand, customers may shed additional load if needed. In the summer of 2015, program participants exceeded contract curtailment goals in all four events called, including 72.9 MW of load reduction on a 95 degree day in July.

Despite the success of this program in 2016, its prospects are diminished going forward without adjustments to the current program. Of the three customers that were active in the program in 2016, one has left this program to participate in the Energy Partner program (see below) and another customer – which represented 87% of the historic capacity – has closed. The remaining customer has 1.8 MW of capacity contracted with the program.

PGE is exploring ways of making this program more flexible to customer needs while still addressing our load reduction requirements. Schedule 77, along with Energy Partner, will be adjusted in 2017 to be more inclusive of small and medium customers, given diminished available load in the large industrial sector.

Table 16: Schedule 77 Program Progress

Metric	2012	2013	2014	2015	2016
Participants	1	1	3	3	1
Maximum Available Winter Capacity (MW)	16.0	17.0	18.3	18.3	1.8
Maximum Available Summer Capacity (MW)	16.0	16.0	18.3	18.3	1.8

Status: Active Deployment

Energy Partner

PGE launched the Energy Partner automated demand response (ADR) pilot for commercial and industrial customers in 2013. It uses automated controls to enable participating customers to respond to event signals within as little as 10 minutes. The pilot is available to customers with 30kW of demand or higher. At its peak, the pilot was capable of 13.1 MW in winter 2016-2017, but has since reduced to 8.3 MW due to loss of customers to direct access and some reduced nominations from a small set of poor-performing participants.

Table 17: Energy Partner Participation and Progress

Metric	2013	2014	2015	2016
Participants	2	24	39	57
Maximum Available Winter Capacity (MW)	0.3	6.3	6.3	13.1
Maximum Available Summer Capacity (MW)	0.3	2.7	9.1	11.1

Status: Pilots & Evaluation

Next Steps: The current program implementer, EnerNOC, has opted to no longer run the program and will leave at the end of the summer 2017 season. PGE has engaged with Navigant to conduct interviews of participants and non-participants, benchmark against similar programs, and provide recommendations on program re-design. PGE is currently reviewing proposals from an RFP soliciting solutions for all of our nonresidential customers, looking at both firm and non-firm products. We plan on selecting a vendor(s) in May of 2017 with a goal of having the new program in place by the fall of 2017.

Smart Thermostat Demand Response Pilot (Rush Hour Rewards)

In 2015, PGE filed a request for deferred accounting (Docket No. UM 1708, Order No. 15-203) to launch a residential smart thermostat direct load control (DLC) pilot which leverages internet-connected smart thermostats as a demand response asset. The pilot launched with Nest in the winter of 2015 (Nest's first winter DR program). The pilot features a bring-your-own-thermostat design making it a great opportunity for our customers who have already taken steps to be more energy efficient, to also find a simple, easy way to shave their peak energy usage. Customers with heat pumps, electric resistance heat, or central air conditioners are eligible to participate. Participants receive $25 for signing up and $25 for each program season (2/year). As of May 2017, the program had 3,439 customers enrolled in the winter program and 3,605 summer participants. The program has completed an initial impact and process evaluation of the first program year with Cadmus and cost-effectiveness analysis, both of which indicate that the program has been successful at achieving cost-effective demand reductions.

Table 18: BYOT Pilot Participation and Progress

Metric	2015	2016
Participants	142	2,512
Maximum Available Winter Capacity (MW)	0.1	0.3
Maximum Available Summer Capacity (MW)	n/a	2.3

Status: Pilots & Evaluation

Next Steps: Based on the positive results of our analysis, we plan to expand the current offering to non-Nest thermostats in the second half of 2017. We released an RFP in April of 2017 and plan to have a vendor selected in May. We believe this expansion will allow us to understand how other smart thermostats perform while expanding to customers not addressed by the existing program with Nest.

Multi-Family Water Heater

The 2016 Integrated Resource Plan identifies significant cost-effective demand response in the existing water heater market. In April 2017, PGE submitted a deferral request to implement water heater demand response pilot targeting multifamily residences. The program pilot would run through the end of 2019 and targets 8,000 water heaters over the 30 month pilot.

This program would work with property managers to target large multifamily complexes to enroll in direct load control of existing and new smart water heaters. Two-way communicating switches would be used for existing water heaters and, where appropriate, PGE would help buy down the cost to upgrade old water heaters to new, smart water heaters capable of connecting to a communications module.

Status: Planning Pilot

Next Steps: PGE has engaged with vendors and, pending commission approval, will go into the field in Q4 of 2017. We will be conducting an ongoing process and impact evaluation of the program and will share evaluation reports at the end of each program year.

Smart Water Heater

PGE has conducted a "smart" water heater demand response demonstration using "off-the-shelf" water heaters in 14 employee homes in 2016. This pilot tested load and customer impacts on our employees from year-round load control using the CTA-2045 protocol. The pilot demonstrated a reduction in system peak of about 0.35 kW and the ability to regularly shift about 1.5 kWh of energy use to a period when power costs are lower:

Table 19: Typical Water Heater Load Reductions, by Type, Mode, and Peak Period (kW/water heater)

Peak Period	Resistance Water Heater		Heat Pump Water Heater	
	Routine	Emergency	Routine	Emergency
Winter AM Peak	0.35	0.60	0.28	0.40
Winter PM Peak	0.30	0.50	0.20	0.30
Summer PM Peak	0.25	0.40	0.18	0.25

PGE used this experience to inform the development of a regional pilot with BPA with 8 participating utilities. The pilot will engage 120-200 PGE residential customers to have them install a communication module that "plugs" into their electric water heater (no electrician is required for the installation). The communication module provides a hybrid communication method: control signals are broadcast using a FM radio station, while return information is collected over the Internet using the customer's Wi-Fi network. This is a secure, low-cost, low-latency, and high reliability communication method. The pilot with a total customer base across all utilities of 400 to 600 homes, will implement various control strategies so as to quantify peak load reductions, and quantify load shifting capability per tank (i.e. reduce load in evening to shift consumptions to night [store wind], or reduce load in morning to shift consumption to midday [store solar]). The pilot will also test customer acceptance of frequent load control without notice.

A tariff (Schedule 3) was approved by the OPUC on March 22, 2017. Participating Customers will receive a $50 "enrollment" incentive payment after PGE verifies one month of connectivity to the Customer's Wi-Fi network. A Customer that has participated, as defined in the special conditions, for 12 months will receive a $100 participation incentive at the end of the pilot.[15]

Status: Pilots & Evaluation

Next Steps: PGE anticipates recruiting to occur in Spring/Summer, 2017. First load control events will be called in July. The pilot will run through Summer, 2018. As an outcome of the BPA regional pilot, a business case to justify funding a market transformation effort (with NEEA) such that all new water heaters sold in the Pacific NW are sold as smart water heaters with a standard communication interface, thus enabling a customer-friendly and affordable means to implement this demand response capability.

3.3(d) Transportation Electrification

In the long term, PGE envisions a world where hundreds of thousands of electric vehicles are on the road and meaningfully supporting the operation of the electric grid. As electricity continues to grow as a transportation fuel, and electric vehicle adoption grows in our service area, we see EVs playing a key role in helping integrate the new variable resources that will be added to PGE's grid in order to meet the 50% Renewable Portfolio Standard mandate.

Table 20: Cumulative EV Forecast in PGE Service Area without PGE intervention[16]

Year	No. Vehicles
2017	10,430
2020	40,858
2025	113,265
2030	205,092
2035	314,492

Analysis suggests that each new electric vehicle added to a home in our service area provides a benefit to all of our customers today. The typical electric vehicle uses existing grid infrastructure when it is otherwise underused, thereby creating downward pressure on prices. Accordingly, electric company programs that encourage our customers to acquire EVs – while ensuring that the vehicle connects to our system as efficiently – if not more efficiently than the standard EV does today – are appropriate to examine.

EV-only (sub-metered) TOU Rate

Through Schedule 7, PGE offers a TOU rate for separately metered service used exclusively for the purpose of EV charging. In order to participate in this option, the customer must (at his or her own expense) install all necessary equipment (including the revenue-grade meter) in order to participate in this option. The sub-metered rate is cost preventative for customers and has ultimately yielded no participation to date.

As an alternative to reduce costs, PGE has considered using "smart" residential charging units with internal metering capabilities; however, there are no industry standards or best practices on utilities measuring, verifying, and performing on-going testing of the metering in these devices to ensure they are consistently revenue grade.

Status: Complete

Employee EV Research Project

To date, PGE has more than 90 employees who own or lease an electric vehicle. In 2016, we launched an employee research project to study charging behavior (home, public, and workplace), TOU rates, and demand response/smart charging.

The project aims to give PGE better understanding on where and when people charge, how TOU rates impact home charging habits (and use of other appliances in the home), and the impacts of curtailing charging loads at home and work. Key elements of the study include:

- **Time of Use:** On average, more than 80% of EV charging happens at drivers' homes—as a result we understand the importance of looking for pricing and control strategies at the premises.[17] As such, half of the participating employees have been randomly selected to be put on Schedule 7's whole-home TOU rate which offers savings of greater than 40% for shifting energy consumption to off-peak hours. The study will compare TOU participants versus non-participants and evaluate impacts on charging behavior as well as energy-use for all devices in the home.
  Note: this is PGE's historic rate schedule and not the pricing options offered in PGE's current TOU pilot program, Flex.
- **Smart Charging:** 35 employees in the pilot are utilizing a DR-enabled home charging station; additionally all employees are eligible for free workplace charging (some of which is DR-enabled). PGE is collaborating with EPRI in studying the interoperability of smart appliances. The centrally-managed charging process allows PGE to signal cars or charging stations to adjust demand in real-time to optimize resource and system utilization. The study aims to evaluate practical feasibility, customer experience, and achievable curtailment from smart charging. Additionally, we will directly engage with several employees to program their vehicles to charge on a schedule.
- **Public Charging Behavior:** all participating employees are responsible for keeping a vehicle charging log to track public charging events. We will be evaluating these logs to better understand what drives people to charge outside of the home and workplace, how often they publically charge, where they charge, and for how long they charge.
- **Survey Data:** Additionally, PGE intends to use the employee group to periodically survey for EV-related insights.

We anticipate that the learnings from this study will inform future program design to help efficiently integrate customer EVs into PGE's grid.

Status: Research

Next Steps: Enrollment for the pilot was launched in January, 2016 and will continue through the end of 2017 (extended through 2018 if additional enrollments are required). Data collection and analysis will go through 2019.

Workplace Smart Charging Pilot

PGE has commenced an employee workplace smart charging pilot at its own workplace sites. Currently PGE has 69 workplace charging spots at 18 sites; 20 of those chargers are DR-enabled. We anticipate piloting this concept with some of our customers, but it is important that we expand this pilot carefully and strategically as curtailment of EVSEs has unique customer impacts not fully comparable to other direct load control (DLC) programs (i.e. heating, cooling, and hot water):

- **Utility of vehicle:** unlikely heating and cooling, EVs are often on the move and not connected to PGE's grid. If a customer does not get a full charge while at work or while patronizing a business, it is conceivable that they may not have enough charge to reach their next destination. We must start slowly with expanding this pilot to ensure a positive customer experience.
- **Impact on our customers' customers:** It is one thing to curtail charging on our own employees at our facilities, however, when we begin curtailing customers' charging stations, we will also likely impact their customers and employees. This creates two-tiers of customer service, again adding to the emphasis that we must start slow to ensure a positive experience for all.
- **Lack of consistent load profiles/use cases:** Unlike many technologies/customer classes, there are no clear load profiles associated with workplace/business charging infrastructure. This raises questions of (1) how much potential value there is with workplace smart charging, (2) how to standardize program design such that programs are still relevant to most, and (3) how do we ensure positive customer experience despite likely different charging experiences at different sites.

The pilot will evaluate: achievable coincident demand reductions, reliability of demand reductions, customer experience (both facilities and end-use vehicle owners). The pilot should yield results that inform future program designs, such as program costs, achievable curtailment, and attribution.

Status: Research

Next Steps: In 2018, PGE intends to collaborate with 1-2 business customers who intend to install 5-20 electric vehicle charging stations at their site(s). We plan to offer those customers incentives to procure charging infrastructure that is DR-enabled and for committing to up to 10 curtailments per year. If the pilot proves successful, PGE may expand the pilot to additional customers in the service area.

Public Charging

Electric Avenue 2.0 at our World Trade Center offices in Portland has been a success; the site, activated on July 18, 2015, hosts four dual-head DCQCs and one dual-head L2 charger. To date Electric Avenue 2.0 has delivered more than 200,000 kWh and powered more than 1,000,000 electric miles. The site's visible and pedestrian-friendly location fosters frequent conversations between EV drivers and passersby. This has been a great way for more people to become aware of the benefits of electric vehicles.

Additionally, PGE has since taken ownership of several quick chargers, which were part of Schedule 344: the Oregon Electric Vehicle Hwy Pilot Rider and originally owned by EVSEs that have since gone bankrupt, to ensure they remain accessible and reliable for those who depend on them.

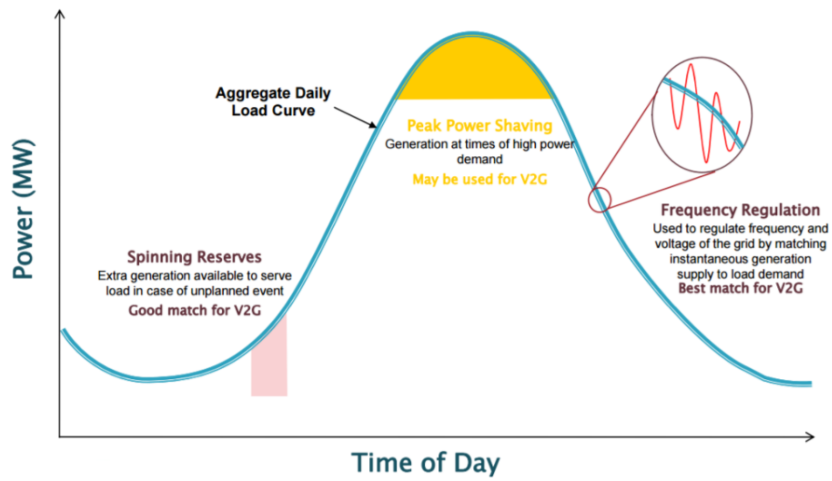
Status: Limited Deployment

Next Steps: PGE has filed an application to OPUC to expand the Electric Avenue Network and to incorporate TOU rates into customer pricing. A discussion of that proposal is included in Section 6.

Vehicle to Grid

It is not difficult to imagine that more than 10% of the vehicles in PGE's service area will be plug-in electric vehicles within the next 20 years. Two hundred thousand PEVs represent 5,000 – 10,000 MWh of potential distributed energy resources that could add value to PGE's grid. For context, PGE delivered 18,971,000 MWh of retail energy in 2016.[18] The large potential storage resource has the ability to provide a variety of vehicle-to-grid (V2G) applications (e.g. Vehicle-to-Home). V2G is used to describe the energy flow back from a vehicle's battery to the electric grid (much like excess generation of a solar array). Potential applications include: spinning reserves for regulating fluctuations in renewables, peak power shaving, frequency regulation, emergency backup power, and other ancillary services.

Figure 3: Visualization of Vehicle to Grid Use Cases[19]



Today, unfortunately, OEM warranties for PEV batteries are "not structured to allow battery discharge onto the grid. V2G may void the battery warranty, depending on the terms of the warranty structure and the design of the battery."[20] As such, no vehicles sold today are enabled for V2G use-cases (though some can be converted by an over-the-air software update). Additionally, V2G applications are further complicated by the fact that drivers need batteries to have adequate charge to accommodate their next trip. "Business models which inconvenience or harm drivers in any way are unlikely to scale; drivers will be less willing to volunteer their vehicle for ancillary services if there is a risk of being stranded with a dead or worn out battery."[21]

Though V2G presents clear challenges, the opportunity it presents creates real potential value for low-cost grid benefit to all customers. Accordingly, we are launching a V2G demonstration project with V2G-enabled Nissan Leaf and a 2-way charging station at a PGE site.

The demonstration project is a partnership with Nissan and will use one PGE fleet vehicle interconnected regularly to a PGE facility using a 10 kW 2-way charging station from Princeton Power Systems (the same equipment used at the V2G pilot at Los Angeles Air Force Base).[22] PGE will utilize an off-warranty Nissan Leaf at the charger to test various charge/discharge scenarios and use cases.

The project will study:

- Interconnection considerations associated with 2-way inverter/charging stations
- Power quality and reliability of exported power from 2-way inverter/charging stations
- Impact of V2G on vehicle's battery, based on various cycling patterns and use cases
- The learnings may inform pilot design with long-term parking sites in our service area (e.g. airports). By partnering with this type of organization we could potentially offer customers discounted parking in exchange for leaving their vehicle connected and available for ancillary services while they are away.

Charging equipment and a vehicle for this pilot was procured and installed in 2016.

Status: Research

The system is undergoing commissioning and testing in Q1/Q2 of 2017. The intent is to begin testing charge/discharge cycles with the charger in 2017.

Section 4. Completed Smart Grid Pilots & Demonstrations

Salem Smart Power Project (SSPP)

The SSPP demonstration project was co-funded by the USDOE under the American Recovery and Reinvestment Act (ARRA) as part of the Pacific Northwest Smart Grid Demonstration. This project provides a substantial educational opportunity for the energy industry and the general public on Smart Grid technologies. The project was initiated in 2010 and formally concluded in 2014, however PGE continues to explore new use cases beyond the original project scope. Recent testing and demonstration include:

- **Reactive Power Support**: PGE demonstrated the ability of the system to provide reactive power on demand in order to support power factor.
- **Voltage Control Utilizing VAr Control**: An automatic program was demonstrated that will control the voltage on the substation bus by regulating the export of reactive power. The system maintains a very stable voltage.
- **Automatic Efficiency Testing:** An automatic program was installed that will analyze the health of the lithium ion battery cells in terms of capacity and roundtrip efficiency. This was previously a fairly manual process but can now be accomplished in approximately an hour without human intervention.

Status: Complete (testing on-going)

Next Steps: PGE and PNNL, with funding received from the US Department of Energy, are currently modelling both the electrical characteristics of the batteries and the financial merits of various use cases. This will inform a future project to optimize the system such that it will engage the highest value use cases in appropriate order to maximize its financial benefits. PGE will work with PSU to implement PNNL's algorithm at SSPC.

Solar Energy Grid Integration Systems (SEGIS)

Initiated in 2008, SEGIS is a partnership between the U.S. Department of Energy (USDOE), Sandia National Laboratories, power-equipment manufacturers, electric utilities and universities to remove the barriers to large-scale general integration of photovoltaic (PV). The effort was expanded in 2011 as a part of the USDOE's SunShot Initiative and has demonstrated:

- Synchrophasor-enabled anti-islanding
- VAR control
- Ramp-rate control
- Power-factor control
- Low-voltage ride through
- Feeder optimization
- Power management functions

Effectively using renewable energy assets and the implementation of PMUs (Phasor Measurement Units) and smart inverters on the grid will enhance reliability and could help regulate power flow. These technologies allow for increased levels of solar PV across distribution feeders due to better voltage support through local reactive power control. Transmission capacity is also improved by sourcing and sinking VAR demand closer to the point of use, improving overall broad system efficiency through line loss reductions.

Status: Complete

Flex Price/Critical Peak Pricing (CPP)

PGE launched a two-year CPP pilot project in November 2011. The pilot was offered to 1,000 customers via Schedule 12. The program used a dynamic pricing structure, based on TOU rates, to encourage peak-load reduction on a general basis, but especially during times of unusually high demand. This behavior was incentivized by peak time events for up to 4 hours each, during which the customers' energy price was approximately five times higher than normal. Customers were informed of events via email and/or telephone.

In general, each customer lowered their peak usage between 0.11 – 0.32 kW during events and there appeared to be a small TOU effect on usage. Because customer satisfaction with the program was low (65%) compared to other pricing programs (75 – 85%), the Company decided to evaluate a variety of other pricing models in the Flex pilot rather than scaling the CPP pilot.

Status: Complete

Salem Smart Power Residential Direct Load Control

A pilot was conducted with 20 conventional water heaters as part of the Salem Smart Power Project (see Section 5). PGE tested a new control strategy where water heaters were dispatched using recommendations from a software-based feeder simulation that sought to improve dispatch economics and improve system reliability in real-time. The tests showed that residential demand response resources could be dispatched based on real-time grid and environmental conditions. This pilot concluded in fall 2013.

Status: Complete

Section 5. Research & Development

5.1. Research Expenditures

Table 21 summarizes R&D expenses by project for 2015 and 2016.

Table 21: R&D Expenses (2015-2016)

R&D Project Name	2015	2016
Agronomy, Acceptability & Potential for Growing Arundo donax in E. Oregon	$ 74,302	$ 20,584
Avery Fuel Cell	$ 39,643	$ -
Biglow Canyon Solar Investigation	$ 21,000	$ 10,000
Capacity Value of Energy Efficiency - Oregon BEST	$ 50,000	$ -
Cascadia Lifelines Program 2013 - 2017	$ 50,000	$ 50,000
Combined Solar/Wind Power Monitoring to Assess Complementarity at DDHS	$ 248	$ -
Comparative Studies of Energy Storage	$ -	$ 25,000
Computer Based Modules for Sulfur Hexafluoride SF6	$ -	$ 7,578
Develop Market to Assess DSG Program Target Capacity	$ -	$ 1,403
Development of Distributed Battery Control Methods and Business Case	$ 85,930	$ 119,667
Electric Vehicle Behavioral Assessment	$ 54,875	$ 104,929
EPRI - Sustainability Benchmarking for Utilities	$ 837	$ -
EPRI P161 Collaborative Field Demonstrations of DR-Ready Appliances	$ 20,040	$ 27,273
EPRI P173: Bulk Power System Integration of Variable Generation	$ -	$ 66,746
EPRI P174: Integration of Distributed Energy Resources	$ -	$ 35,080
EPRI P183: Cyber Security	$ -	$ 89,668
EPRI P94: Energy Storage & Distributed Generation	$ -	$ 90,730
EPRI Program 180 - Distribution Systems	$ 163,535	$ 166,249
EPRI Program 62 - Occupational Health and Safety	$ -	$ 85,449
Investigate Wake Effects on Biglow Canyon Phase 3 Production	$ -	$ 20,000
Investigating Use of Ductile Iron Poles for T&D Infrastructure	$ 20,000	$ -
Joule Bank System	$ 139,249	$ 17,076
Non-Wires Solution to Transmission Congestion	$ -	$ 18,500
NuScale Modular Reactor Study Group	$ -	$ 5,000

R&D Project Name	2015	2016
OSU Real-time Load Modelling OSU's S-Phasor Network, Microgrid Reliability	$ -	$ 25,000
OSU Wave Energy Research	$ 25,000	$ 25,000
OSU Wind Energy Integration Research	$ 25,000	$ -
PSU Wind Tunnel Research - In support of Biglow Canyon	$ 20,000	$ -
Salem Smart Power Center Use Case Test & Validation	$ -	$ 67,743
Second Life Battery Research - OIT	$ -	$ 25,000
Seismic Capacity on Transmission Lines	$ 100,000	$ -
Smart City/Streetlights	$ -	$ 36,000
Solar & Meteorological Data Collection/Evaluation	$ 10,000	$ -
T&D Operational Data Analytics	$ 135,640	$ 294,200
Thermal Storage as Resource in Residential Homes	$ 15,000	$ -
Torrefaction Testing and Implementation	$ 206,633	$ 345,532
Using the SSPP as a Dispatchable Standby Generator	$ -	$ -
Via Pickup Truck & Exportable Power Demonstration	$ -	$ 52,796
Project Total	**$ 1,256,932**	**$ 1,832,203**
Administrative Expenses	$ 295,853	$ 258,318
Grand Total	**$ 1,552,758**	**$ 2,090,521**

5.2. Research Funded for 2017

5.2(a) EPRI Research

EPRI P094: Energy Storage and Distributed Generation

Energy storage and distributed generation technologies are attracting increasing interest from utilities and regulators as localized flexible grid assets. Storage can act as a buffer between electricity supply and demand, increasing the flexibility of the grid and allowing greater accommodation of variable renewable resources. Distributed generation (DG) entails the production of power at or near load centers, thereby augmenting or substituting electricity infrastructure with DG fuel infrastructure, where appropriate. Both storage and DG may provide temporary solutions for regional and local capacity shortages, and may provide relief to localized transmission and distribution congestion. Technology advances, as well as investment in production capacity, have resulted in significant cost reductions of energy storage and distributed generation. However, the economic use of these technologies still generally requires the user to take full advantage of multiple potential benefit streams ("stacked benefits"). The various applications that contribute to the value of distributed resources have different requirements, and the ways in which these requirements are coincident or competitive are still being explored. Technologies such as fuel cells, microturbines and small reciprocating generators are still relatively expensive in terms of installed capital cost, but low fuel costs and opportunities offered by the application of combined-heat-and-power (CHP) architectures may make them increasingly cost-effective options in the future. It is important to understand the factors that may make storage and distributed generation technologies technically and economically viable in the future, whether the devices are owned and operated by utilities, by customers, or by third-parties. While storage and distributed generation options are rapidly maturing and are beginning to become practical in grid applications, there are still significant challenges to overcome.

2017 Estimated Budget: $95,000

EPRI P174: Integration of Distributed Energy Resources

Increased amounts of distributed energy resources (DER) in the electric grid bring a number of challenges for the electric industry. Utilities may face large numbers of interconnection requests; distributed generation on some circuits will exceed the load; and many operating challenges involving feeder voltage regulation, hosting capacity limits, inverter grid support and grounding options are brought to bear. Furthermore, providing reliable service as DER penetrations increase and electricity sales diminish can also add economic and business challenges to the technical ones. This Program addresses these challenges with project sets that assess feeder impacts, inverter interface electronics, and integration analytics. The Program evaluates case study experiences and strategies related to future business impacts. It also evaluates leading industry practices for effective interconnection and integration with distribution operations. Many of these activities support EPRI's "The Integrated Grid" initiative. Finally, the Program includes lab and field evaluations and demonstrations of improved DER power management and communications. A primary objective of the work in the field is to expand utility hands-on knowledge for managing distributed energy resources—without reducing distribution safety, reliability, or asset utilization effectiveness. Moreover, the optimal integration of distributed energy resources, like solar photovoltaic (PV) generation, has the potential for significant public benefits. These include reduced climate impact of overall electric power generation, potential for more efficient and optimum operation of the electric system through efficient generation closer to the load and even improved resiliency with local generation to provide power during major events on the grid. Achievement requires making these distributed resources a part of the planning and operation process inherent to an Integrated Grid.

2017 Estimated Budget: $40,000

EPRI P173: Bulk Power System Integration of Variable Generation

Recently there has been a significant increase in the implementation of renewable energy, due to both policy decisions such as state-mandated renewable energy standards and federal air and water standards, along with improved economic viability for these resources. Much of the estimated development of renewables comprises variable resources such as wind generation and solar photovoltaics (PV), which when integrated with the grid, create new challenges for maintaining reliable system operation. Future projections are that a more significant build-out of these variable renewable resources is likely at both the transmission and distribution levels. Power system planners and operators will require new tools and resources to ensure a reliable, sustainable, and cost-effective supply of electricity to consumers. New tools needed include improved and/or new sources of system flexibility to respond to and accommodate the increase in energy variability and uncertainty, the development of additional transmission infrastructure to deliver energy from remote locations, and planning and operational methods and software to effectively plan and operate the bulk system with these new resources, many of which may be at the distribution level. This research program addresses these needs and directly supports EPRI's Research Imperatives #2 "Integration of Dynamic Customer Resources and Behavior" and #3 "Integrated Power System and Environmental Modeling Framework." Research is focused on (1) The Bulk Power System Variable Generation Integration research program which provides variable generation integration analytics; (2) development of planning and protection methods, tools, and models; and (3) development of operator methods and tools to reliably and economically integrate wind and solar PV generation.

2017 Estimated Budget: $70,000

EPRI P183: Cyber Security

This program develops an analysis framework to correlate cyber, physical, and power system events including:

- Development of security event scenarios that utilities can adapt to their operational environment
- Identification of operational and asset condition data sources to support event detection; and
- Results and lessons learned from testing and demonstrating scenario detection in EPRI's lab as well as utility host sites.

Utility enterprises are evaluating cyber security threats to their communication networks in a way that integrates that information with other traditional information about equipment health status and power system status. It is now time to integrate this information into a comprehensive and consistent picture, for use by power system operators and communication system operators, in order to provide a system-wide view and to improve coordination of operator responses. This project intends to focus the "Analysis" component of the Integrated Threat Analysis Framework (ITAF) by developing and testing broadly applied use cases and potential data analysis methods to determine when a malicious event has taken place. While the aggregation of data from these domains (Information Technology, Operations Technology, Physical, threat indictors, etc.) provides a view across the entire utility enterprise, determining how to use this information to make decisions will be very challenging. The operational environment will vary day-to-day due to changing conditions (weather, loading conditions, availability of variable resources, planned or unplanned maintenance, etc.) so the use cases must be dynamic and represent a growing knowledge base as opposed to a set of static scenarios. This challenge will require expertise in both cyber security and grid operations. This project coordinates activities of three EPRI research programs: Substations (P37), Grid Operations (P39), and Cyber Security (P183) in a way that is intended to provide broad power industry and public benefits, including better communication between diverse utility personnel and public service personnel.

2017 Estimated Budget: $95,000

EPRI Program 180 – Distribution Systems

Distribution system owners need to continually improve the efficiency and reliability of the distribution system, to accommodate a higher penetration of distributed energy resources (DER), and to maximize utilization of existing distribution assets without compromising safety and established operating constraints. Significant changes to distribution design and operating practices are needed to accommodate these new requirements. At the same time, utilities will continue to grapple with the ongoing challenges of an aging infrastructure, increasing customer expectations, increasing competition for resources, and an aging workforce. Recent experience with major storm events has also revealed a need to re-examine practices for designing, maintaining, and operating the distribution system to improve its overall resiliency. EPRI's Distribution Systems Program has been structured to provide members with research and application knowledge to support planning and management of the grid today and the transition to a modern integrated grid. The Program delivers a portfolio of tools and technologies to increase overall distribution reliability and resiliency; understand the expected performance for specific components throughout its life cycle; assess methods for evaluating the condition of system components; and develop and test new technologies. The program delivers a blend of short-term tools such as reference guides and industry practices as well as longer-term research such as component-aging characteristics and the development of new inspection technologies. Overall, the Program includes research that supports grid modernization and provides tools for planning, design, construction, maintenance, operation, and analysis of the distribution system.

2017 Estimated Budget: $170,000

EPRI Power Quality Knowledge Development and Transfer

Management of electrical power quality issues has never been an easy task, but it has grown even more difficult with deregulation, reregulation, increasingly scarce technical and strategic tools, and a conspicuous lack of unbiased resources for information, collaboration, advice, and problem solving. Moreover, with the ever-increasing use of sensitive digital and electronic equipment in today's economy, PGE's end-use customers are not only demanding higher quality power, but also are calling upon it to help resolve PQ problems within customer facilities. This EPRI supplemental project offers a number of benefits, including: access to EPRI experts and industry peers, access to high-impact resources, such as documents covering a wide range of PQ topics, and access to MyPQ.epri.com, a comprehensive electronic PQ resource providing 24/7 access to more than 500 PQ case studies, PQ technical documents, PQ standards references, indexes, conference presentations, and a wealth of other resources.

2017 Estimated Budget: $20,000

5.2(b) University Collaboration

WSU Power Engineering Energy Innovation Center Data Access

Washington State University's Energy Innovation Center brings together research faculty, business leaders, and governmental organizations to address the technological challenges inherent in the demand for renewable, clean and reliable energy. The Center consists of more than 30 WSU faculty members. Thirteen are in the core areas of power, energy, and computer science. More than twenty are in sociology, economics, psychology, communication, and public policy - helping bridge the gap between science and society. The Center also collaborates with a wide range of government and industry partners. The Center's focus areas include renewable energy; social and economic incentives; information collection, delivery, and analysis; decision support; efficient use of right-of-way and associated economic issues; and cyber security of the smart grid. Many of these topics are of interest to PGE especially in light of Oregon's SB 1547 mandate for PGE to achieve 50% renewable power by 2040. PGE participation in ESI can lead not to just data and information access but also to collaborative research that is co-funded by larger granting institutions such as the US DOE.

2017 Estimated Budget: $15,000

PSU - Battery Backup Field Demo; residential & grid support

As electric utilities experience increasing penetration of distributed renewable power generation in the form of wind and solar resources at the distribution feeder level, there is heightened awareness for the need to ensure acceptable power quality from both safety and reliability perspectives. It is increasingly clear that energy storage devices will be needed to help store energy when it is abundant and to release it when it is needed the most. Promulgation of energy storage devices also enables the grid to proactively respond with demand side controls to limit peak power demand. If available in sufficient capacity, energy storage devices can help resolve the present "non-dispatchability" of wind and solar power assets which currently dominate the renewable power generation resource stack mix. In doing so, it helps advance the societal demand for incorporating more of these types of renewable power in response to carbon emissions reduction policies through the promotion of renewable energy standards (RPS).

To accomplish this on a more distributed basis requires that PGE take steps similar to those described above for incorporation of renewable power sources such as wind and solar. But this can also be done using energy storage alone on a distributed basis. Emplacement of appropriate battery energy storage or other energy storage devices at residential locations is one of these possibilities. PGE has collaborated with Portland State University's Electrical and Computer Engineering (ECE) Department to take steps in this direction. This collaboration is testing use of a very safe aqueous ion battery that has more energy density than power density and thus would be suitable for household use. The vision is that PGE would own and maintain the 8 kW inverter and the nominal 30 kWh battery as investment assets so that:

- PGE through, an agreement with the premise owner, can use the battery
- Controls for the battery would enable demand response, wind firming, etc.
- Upon loss of utility power a disconnect allows the battery to power the home

- Upon re-gaining utility power the inverter will allow automatic grid re-synching
- The inverter will also monitor and control for islanding conditions
- The meter for the system will track energy for home and grid separately
- The meter also supports circuitry to facilitate telemetry, command and control

Because of PGE's high reliability it is probable that the battery will service PGE's purposes for the vast majority of the time. For the home owner, the battery-inverter will provide the peace of mind attendant to having back up power for that rare and short period of time that is more than adequate for average loss of power periods experienced on PGE's grid. Also, the home owner knows that the battery will be supporting the increased penetration of renewable power such as wind and solar.

2017 Estimated Budget: $130,000

PSU - Non-Wires Solutions to Transmission Congestion

It is well known that the Pacific Northwest transmission grid is congested. This is particularly true of east-west electricity movement but also in localized areas. The congestion has grown over the years due to load center growth on the west side of the Cascade Mountains and the proliferation of wind power plants on the east side of the mountains. As the Bonneville Power Administration (BPA) controls 75% of the region's transmission system this is a top of mind concern. Since PGE has a heavy reliance (as do virtually all electric utilities in the region) on the BPA system it is also of import to the Company and its customers. As an example, in southwest Washington and Multnomah County, Oregon where the population has more than doubled there has been no transmission line upgrade or expansion for forty years. This led the BPA in 2011 to propose the "I-5 Corridor Transmission Reinforcement Project" to construct new transmission to help relieve congestion for Cowlitz, Clark and Multnomah Counties. This is roughly a 70-mile run extending from Longview Washington to Troutdale Oregon with construction alternatives being evaluated on the Washington side of the Columbia River. The ability to construct new transmission lines is expensive, daunting to say the least and given recent experience might not be possible at any price. The advent of large grid-scale energy storage systems of which PGE's Salem Smart Power Center is an example suggests the possibility of a non-wires option to help relieve transmission congestion. Energy storage can effectively serve as a "wide spot" in the pipe and with a sufficient number of installations could eventually widen the pipe entirely and be a viable solution to the congestion issue. PGE in collaboration with Portland State University proposes a competent and authoritative research paper to set context and to analyze this possibility in light of recent energy storage advances.

2017 Estimated Budget: $20,000

OSU - Cascadia Lifelines Research

The Cascadia Lifelines Program provides essential and unique engineering solutions for our lifeline providers, including cost-effective retrofit strategies for infrastructure subjected to long-duration shaking resulting from a Cascadia Subduction Zone event. The project provides improved prediction of ground-shaking specific to Oregon conditions, predicted seismic behavior of soils unique to the Willamette Valley including the liquefaction potential, and system optimization of interdependent lifelines. The impact of this research will help assess cost-effective approaches to increased resilience, resulting in saved lives and improved business continuity for western Oregon and PGE's service territory. In joining this program effort headed by Oregon State University PGE continues taking a pro-active approach in minimizing the impact of the next devastating earthquake on its customers, and doing its part in improving Oregon's ability to bounce back from such an event. As a secondary benefit, teaming with OSU on this research will foster collaboration between OSU and PGE, and give PGE ready access to the team of seismic hazard mitigation experts at the university. R&D funding is $50,000 per year for a 5-year commitment or $250,000 over five years; PGE occupies a seat on our management board that guides the OSU research priorities. The dollar commitment on behalf of PGE customers is substantial as is the match from other utility and related infrastructure providers (e.g., BPA, ODOT, NW Natural, EWEB, Port of Portland and others) will be matched five to 10 fold.

2017 Estimated Budget: $50,000

OSU Wave Energy Support

PGE continues its support of OSU to develop and test intermediate/full scale wave energy generation devices in the Wallace Energy Systems and Renewables Facility (WESRF) Lab (linear test bed), Hinsdale wave flume, and/or Northwest National Marine Renewable Energy Center (NNMREC) open ocean test berth – Pacific Marine Energy Center (PMEC). This will demonstrate and expand the available renewable resources for PGE customers.

2017 Estimated Budget: $25,000

Inspection and Correction – Below Grade Corrosion

PGE is very interested in developing an inspection and correction program that facilitates learning more about below grade corrosion for its galvanized lattice towers, galvanized tubular steel poles and weathering steel tubular steel poles. The research should also include a survey of industry best practices. Presently, the Company has very little experience with evaluating the below grade condition of its steel structures. PGE would like to employ the services of a competent vendor or OSU to research different techniques to evaluate below grade corrosion as well as devise and kick off a pilot program to begin looking at a sampling of its transmission towers. Early discussions between PGE and OSU note that existing corrosion rate monitoring techniques were mainly developed for measuring corrosion rate of metals with accessible measurement surfaces. For metals embedded in soils, the locations and sizes of the corroding surfaces are unknown because embedded steel surface in soil is inaccessible for direct measurements due to the presence of the thick soil cover which is electrically resistive. This limitation yields existing corrosion rate measurement techniques inaccurate, unreliable, and in most cases, unusable in field applications. The main hypothesis of the proposed research is that half-cell potentials on the soil surface can be used to identify the locations and sizes of anodic and cathodic sites on the embedded metallic surfaces. The idea is similar to the concept of half-cell potential mapping for reinforcement corrosion in concrete, but with considerably different challenges. The soil cover has significant differences from concrete cover in chemical composition, thickness, porosity and microstructure. In addition, corrosion patterns of metals in soils are not the same as the patterns in concrete. Therefore, feasibility and applicability of half-cell potential mapping process need to be investigated. The proposed research is a multi-year effort with the following objectives:

- Year 1: Experimental investigation of the feasibility of half-cell potential mapping technique to identify corrosion of metals embedded in soils and identification of critical parameters affecting measurement accuracy.
- Year 2: Development of testing protocols to use half-cell potential mapping technique as part of regular field inspections by PGE.

Research will include the efficacy of mitigation as well as correction methods including: below grade coatings, ground sleeves, grounding techniques, and cathodic protection. PGE has been in discussions with Oregon State University School of Engineering to craft a potential research agenda and attendant scope of work. It is likely that BPA will also find this research valuable and may also contribute funds to expand the work (e.g., different soil types, tower designs, etc.)

2017 Estimated Budget: $60,000

Real-time Load Modelling OSU's Synchrophasor Network, Microgrid Reliability

The goal of this project is to better understand load models in order to advance protection of the next generation (integrated grid) power transmission and distribution infrastructure. With assistance from the growing PMU network at OSU, a composite dynamic load model can be estimated in real time and provide useful insight into the design of microgrid protection schemes. This will address challenges such as reverse flows, automatic reclosing, or delayed relay tripping. This project will provide PGE and its customers with insights about the benefits of deploying phasor measurement units (PMUs) at the distribution level yielding improved analysis of anomalies from modern, non-traditional loads, as well as synchronization between transmission and distribution level sensing.

2017 Estimated Budget: $30,000

U of O, Regional Solar Radiation Data Center Project

This project supports the University of Oregon's longstanding collection and storage of regional solar energy data and the maintenance of calibration equipment. This data is supplied to the U. S. Department of Energy's National Renewable Energy Laboratory (NREL) and made available to all Utilities for siting of Utility scale solar projects. The calibrated solar instrumentation can also be used to validate PGE's present and future distributed solar photovoltaic (PV) resources performance; ancillary meteorological data will be used to estimate effects of wind on distributed PV solar resources.

2017 Estimated Budget: $10,000

5.2(c) Industry Partnerships and Other PGE Initiatives

CTA-2045 EPRI demo of "Smart" water heaters & EVSE (PEV 240V chargers)

EPRI has convened a group of utilities, e.g. Duke, Southern Company, AEP, BPA, TVA, appliance manufacturers; for PGE: water heaters and electric vehicle supply equipment (EVSEs) and communication device makers to conduct field demonstrations targeting 10 units of each type of appliance; mostly at employee homes. The goal is to advance end-to-end capability of demand response (DR) using the CEA-2045 communication interface (also known as the appliance socket.) This is a three phase effort beginning with project planning in 2013. Projected field deployment and demonstration starts between mid-2014 to early-2015. Non-EPRI program follow up and evaluation in 2016. With this proposal PGE intends to test demand response (DR) with hot water heaters and EVSEs. Expected benefits to PGE include: (1) Influence the demand responsive behavior of appliances (by providing requirements to manufacturers thru EPRI); (2) Advance efforts that PGE proposed it would pursue as part of PGE's Integrated Resource Plan (IRP) and in PGE Smart Grid reports to OPUC and finally, (3) Advance or otherwise support PGE's Retail Market Strategy to provide innovative solutions for PGE customers.

2017 Estimated Budget: $60,000

T&D Operational Analytics

Over a period of 3 years, initially proposed for 2014 - 2017, PGE's Transmission and Distribution (T&D) Asset Management group has initiated research into a detailed analytics effort involving meter and other T&D data. This has been a long planned effort with initial scoping in 2014 that has involved looking for adequate software and vendors to provide the "big data" analytics capability and long-term support. Asset Management is close to concluding best options and thus desires to proceed. This initial pilot will drive PGE's grid optimization efforts in support of a smarter grid (integrated grid) and will be very economic based on initial cost assessments. It is also consistent with PGE's Smart Grid Roadmap.

2017 Estimated Budget: $185,000

NuScale Modular Reactor Study Group

PGE has the opportunity to assess the development and potential commercialization of the NuScale small modular reactor technology. PGE staff will do this by being part of a regional study and advisory group that has been assembled to periodically review developments regarding technical and licensing advances.

2017 Estimated Budget: $5,000

PGE Employee EV Charging Behavior Research

With the increased penetration of electric vehicles (EV) and supporting infrastructure -- PGE needs to research various concerns as this use ramps up; in particular attempt to understand:

- charging and driving habits of EV customers
- battery life & degradation as it relates to a driver's charging & driving habits
- impact of TOU rate schedule on EV charging
- commuting habits of EV drivers

PGE has pursued this research via studying the driving habits and usage of PGE employees as part of this R&D project.

2017 Estimated Budget: $170,000

Biomass Supply Chain Development in Support of Boardman Conversion

Since 2009, PGE has investigated the potential to use torrefied biogenic biomass to displace coal at its Boardman Power Plant. This has been coupled to the need to pre-process the biomass through torrefaction in order to make the fuel sufficiently friable (crispy) so that it can be ground to a fine powder in the Boardman pulverizers. PGE has done early exploration in partnership with OSU Extension into a biomass supply chain via energy grass agronomy especially for Arundo and Sorghum. In 2016, PGE worked with Oregon Torrefaction, LLC to explore the availability of woody biomass derived in part, from USFS Forest Stewardship contracts out the Malheur National Forest. As Boardman gets closer to its commitment to cease use of coal at the end of 2020; PGE will need to firm its views of what will be the potential biomass supply chain components sufficient to fire the Plant at 30% to 40% capacity.

2017 Estimated Budget: $100,000

Torrefied Biomass Fuel Test Burns for Multiple Days - Proof of Concept

Since 2010, PGE has embarked formally on a large R&D effort to assess the feasibility of displacing coal at its Boardman pulverized coal plant with torrefied biomass. This project extends that effort with work to fine tune both the production and the use of the new fuel in the Plant's boiler. The project will also support evolution of new fuel handling, processing and safety procedures associated with both green and torrefied biomass. The project will also closely monitor torrefied fuel performance and emissions in both co-fire, as a transition, and 100% torrefied biomass applications.

2017 Estimated Budget: $433,293

Yamhill County Landfill Gas Potential for Renewable Power Generation

PGE will participate in R&D consortium with Volta power to investigate potential of landfill gas in Yamhill County. This project will test the capability of a small engine on various types of landfill gas. The potential for using this gas for renewable power generation in Oregon will also be investigated.

2017 Estimated Budget: $5,000

Section 6. Future Smart Grid Initiatives

6.1. Transportation Electrification

In the passing of Chapter 28, Oregon Laws 2016, the state legislature acknowledges that there is a role for electric companies to play in accelerating transportation electrification. In December 2016, PGE filed applications for four pilot proposals to promote customer acquisition of electric vehicles, facilitate electric vehicle use through a reliable and accessible charging network, and build a foundation of knowledge and experience that will enable PGE to most efficiently integrate electric vehicles in the future:

6.1(a) Electric Mass Transit 2.0

PGE has proposed a pilot to install and manage 6 electric bus charging stations (5 depot chargers and 1 en-route charger) for use by TriMet. PGE's involvement in the pilot will allow TriMet to use grant funding from the Federal Transit Administration (FTA) to purchase an additional electric bus, thus enabling the electrification of an entire bus route. Each bus will have a roughly 250 kWh battery; for context, their combined energy rating (1.25 MWh) will be equal to PGE's Salem Smart Power Center. By owning and managing the charging infrastructure, PGE will be able to obtain key learnings that will allow us to most advantageously integrate the considerable demand that may emerge from future electric bus charging infrastructure. The pilot will evaluate distribution system impacts and customer service considerations by studying coincident peak, non-coincident peak, feeder voltage dynamics, charging behaviors, and load profiles.

6.1(b) Outreach and Technical Assistance:

The largest barrier to electric vehicle adoption is lack of consumer awareness. To raise awareness of the benefits of driving electric, we have proposed a 5-year pilot for strategic outreach, education, and technical assistance. The pilot could provide technical assistance for commercial and industrial customers (including non-profits that support low-income communities), education for key industry stakeholders, partner rewards pilots, and market transformation. We will leverage existing outreach channels and a wide range of partners to most cost-effectively reach key audiences.

6.1(c) Community Charging Infrastructure Pilot:

If approved, PGE plans to build on the success of Electric Avenue, a group of five electric vehicle stations located at World Trade Center in downtown Portland, by building six additional Electric Avenue sites. The sites will each include up to four dual-head fast chargers and one level 2 charger for accessibility. Similar to a gas station, this model co-locates several chargers, increasing the chance that drivers in need will be able to find a functional and available charger, thereby effectively improving the availability and reliability of public charging infrastructure. The network will also include the 11 charging stations owned by PGE as a legacy of the EV Highway pilot. Our vision is to have these sites – geographically dispersed throughout the service area – serve as a harbinger of the availability of electricity as a transportation fuel. The sites will increase the visibility of electricity as a transportation fuel and empower the many customers who need to see convenient public charging infrastructure in order to consider an EV. An exciting feature of this pilot will be to examine the impact of community charging infrastructure on increasing the adoption of electric vehicles by transportation network companies (e.g., Uber and Lyft), car-sharing companies (e.g., Reach Now), and the home-charging challenged (i.e. those who live in multifamily buildings or do not have off-street parking with electric service). The pilot will allow us to test price signals to encourage off-peak charging, promote charging when excess renewables are available, and (in the future) enable (and reward) customers to discharge their vehicle batteries to the grid. Prices for charging at these stations will be in line with existing market rates and may employ time-variant pricing to promote charging at times aligned with the needs of today's electric system.

6.2. Distributed Energy Resources

6.2(a) Smart Inverters

PGE owns or operates 24 smart inverters at 12 PV solar installations totaling 5.3 MW (DC) of nameplate capacity. PGE commissioned a white paper in 2013 in collaboration with Portland State University, titled *Smart Inverters for Photovoltaic Resource Integration, Portland General Electric*.

Through efforts under SEGIS grants, PGE has demonstrated the ability to control inverters to:

- remotely connect/disconnect systems
- adjust power factor
- provide curtailment control
- adjust ramp rate

Note: 3 of the 12 PV locations and 4of the 19 smart inverters are only capable of remote disconnect/reconnect

In addition to PV use cases, the 20 smart inverters at SSPC enable functionality such as transactional control and frequency regulation.

In order for PGE to realize the benefits of smart inverters at a utility scale, broad-scale enablement and adoption of smart inverter technology is required (on the order of $\geq$ 20 MW). Because current industry standards (UL, IEEE, etc.) do not support deployment of smart inverters, no customer owned/operated PV systems have utility-enabled smart inverters.

PGE's planned efforts around smart inverters are to encourage broader adoption of the technology:

- Continued involvement in the development of industry inverter standards, particularly UL-1741 and IEEE-1547
- Involvement in OPUC workshops on smart inverters
- Advocate for widespread adoption of smart inverter[4]
- Look for R&D opportunities on how to maximize smart inverter benefits

[4] PGE is supportive of Western Electric Industry Leaders' (WEIL) proposed efforts to encourage widespread adoption of smart inverters that promote renewable integration.

6.2(b) Strategic Deployment of Distributed Energy Resources (DERs)

PGE's planned GIS system paired with AMI data and T&D planning processes could provide better insight into where our peak summer loads are and where overloaded equipment is. With these tools, the Company may evaluate strategic deployment of intermittent resources such as solar in locations where the impact could defer or offset capital investment or maintenance.

PGE is currently evaluating locations for energy storage deployment (for HB 2193); in this process, PGE is using asset management and risk reduction tools to explore approaches for identifying optimal locations for particular DERs.

6.2(c) Bulk Thermal Storage

In 2016, PGE completed successful testing at PSU of a laboratory prototype of a system where an air-source heat pump charges a large thermal storage tank at times to minimize cost for the utility. The prototype design leverages a home's space and hot water heat pumps but has them use the thermal storage tank (instead of outside air) to meet the customer demand. The prototype validated previous modeling work that demonstrates substantial energy and on-peak power savings.

If time permits in 2017, PGE will attempt to engage NEEA and/or a HVAC manufacturer to determine their interest in commercializing a design. If successful the next step would be a field prototype demonstration to validate a field design.

6.2(d) Distributed Energy Resource Testbed

In its final comments filed on PGE's 2016 IRP (LC66), OPUC Staff recommends the implementation of a DR testbed to assess the full achievable market penetration of demand response in our service area. This project would identify one or more areas on the grid experiencing high growth and containing a diversity of customer types to test concentrated penetration of demand response programs, rates, and technologies.

PGE sees value in this idea and will begin to scope out a proposal through a team of T&D and customer program staff. In the coming year, we will work to identify potential sites and engage with stakeholders to gather input on research objectives and approach.

PGE thinks there may be additional value to expand the scope of the testbed to be inclusive of DERs generally, not just demand response. While the focus in the near-term should be on meeting our capacity needs through the most cost-effective means (namely DR), the testbed concept provides a foundation for testing other concepts such as customer-sited storage, smart inverters, microgrids, and advanced control of electric vehicles. The technology investments required to enable the full benefits of DR, particularly the potential value to the distribution system, may result in lower costs in testing additional DERs in these areas of the grid. We believe we should leverage that foundation to the greatest extent possible and therefore will explore development of the testbed to be inclusive of DR and other DERs.

6.3. Systems and Tools

6.3(a) Distribution Management System (DMS)

A DMS would enable real-time management of the distribution system at a more granular level than is capable today. In addition to automatic switching, including fault location, isolation, and restoration, the DMS will support enhanced situational awareness for our distribution operators. The DMS will support real-time network connectivity analysis, assisting the operator in knowing the operating state of the distribution network indicating radial mode, loops and parallels in the network. The DMS will also facilitate State-Estimation which provides insight into system voltages and power flows in areas which are not metered. The State-Estimator enables advanced application such as Load Flow Analysis and Contingency Analysis tools which can predict where system limitations may arise, and allows operators to explore mitigating actions in a simulated environment to ensure adequacy. These tools will also support a more integrated Volt-Var Control (VVC) for enhanced system efficiency, with respect for a growing penetration of variable DERs. All of this leads to better reliability, improved power quality, and increased operational efficiency, especially given the expectation of an increasingly dynamic distribution system.

PGE is considering adding a DMS in the 2018-2020 timeframe, however, a deployment is not likely until there are a number of DA projects being deployed.

6.3(b) Prepaid Metering

With prepaid metering, customers can pay a set amount of money for their energy use up-front and have daily usage fees deducted from the credit balance. Participating customers are provided frequent communications, alerting them to their remaining balance and how many days of service remain before service will be disconnected until additional payment is made. For budget-conscious customers or customers who move regularly (e.g. student populations), this program can be a valuable tool for managing energy spending. In addition, it gives participants a strong incentive to pay attention to their energy use.

Implementation of a voluntary prepaid metering pilot would not be pursued until CIS and MDMS replacement is complete. Before implementing any such pilot, PGE would actively engage Staff and stakeholders (including CAAs and non-profit community based organizations) on pilot design.

6.4. Smart Cities

PGE serves 51 cities and a number of municipal entities within its service area. Although these cities and municipalities are evolving at different paces with different priorities, we are seeing a growing interest in:

- 'Smart' infrastructure (lighting controls, environmental sensors, traffic monitoring, high-speed internet service)
- Improved resiliency (disaster preparedness)
- Reduced carbon footprint (renewables, electric vehicles)

PGE is current evaluating several near term opportunities with municipality customers that include a variety of technologies: smart street lights, energy storage/microgrids, autonomous vehicles, and EV charging infrastructure.

In order to effectively partner with the cities and municipalities we serve, PGE is assessing their needs, technology viability, and resource requirements:

- **Market Assessment:** Some information is available, but in most cases a more detailed assessment of smart infrastructure plans, resiliency needs and sustainability initiatives should be conducted.
- **Technology Assessment:** Need to develop an organized approach to identifying and screening relevant technologies, establishing priorities for future pilot projects.
- **Identify Resource Requirements Associated with Near-Term Opportunities:** Assets, dedicated FTEs, funding.

Section 7. Related Activities

7.1. Physical Security (Hardening)

Though many smart grid technologies improve system resilience to downed wires, poles, and other T&D equipment, PGE is continually looking beyond automation for cost-effective ways to improve the physical integrity of the Company's assets. PGE has an industry-leading vegetation management program and is taking significant efforts to improve wildlife control efforts and asset security.

7.2. Information Technology

7.2(a) Cyber Security

While the smart grid is designed to be more reliable, safer and more secure than the traditional grid, the systems developed to monitor and automate grid operations could increase the footprint for cyberattacks, which could undermine reliability. PGE has actively revamped internal networks and continue to strengthen its capability "secure-by-default infrastructure zones." These zones are being expanded with a redesign of PGE communication network, which are the backbone to support sensitive command-and-control systems (CCS), such as AMI, SCADA and DSG, in a consistent, unified, predictable, repeatable and automated fashion. These zones are implemented to support smart grid interoperability demand, with a consistent architecture, technology footprint and a management toolset. PGE is currently building out an integrated security operations center, to better serve the company to respond to new vulnerabilities or threats, that may affect smart grid technology. Since smart grid relies on the unified integration of many disparate systems operating in unison, this consistent approach to infrastructure, architecture and security is critical to the interoperability and flexibility necessary to adapt to changing uses of a smart grid. Additionally, PGE has adopted the National Institute of Standards and Technology's (NIST) smart grid interoperability, security, and privacy standards. These standards outline best practices that are utilized across the industry.

7.2(b) Data Privacy

During the next five years, PGE will continue pursuing the following cyber security initiatives:

- Continue moving the CCS environments in secure-by-default infrastructure zones
- Extend monitoring capabilities into the CSS environments
- Develop repeatable physical security standards for CCS environments, where applicable
- Implement CIP compliance for network systems
- Implement a Risk Management Framework to provide clear understanding of risk associated with the CCS environment.
- Implement technology to provide trusted computing environments within hardware systems
- Implement autonomous threat response capabilities to automatically detect and mitigate threats and vulnerabilities the grid and organizational networks.

7.3. Strategic Asset Management

T&D Strategic Asset Management (SAM) is a department housed in PGE's Customer Service, Transmission and Distribution group since 2013. The team supports risk management in the T&D asset base by identifying high risk assets and areas of the T&D system, developing and evaluating risk reduction options, and advocating for risk reduction solutions that demonstrate the most economic value to customers and PGE. The primary deliverables produced by SAM are economic life models for significant T&D asset classes and asset systems, an annual system risk assessment and associated Risk Register, long-range plans for risk reduction in the asset base, and investment recommendations to support plan execution.

Threats to reliability are the most significant threats evaluated by SAM in its economic life models, taking into account factors such as asset age and condition, level of exposure to external causes of failure (e.g., heavily forested areas), loading, and probable outage duration should a failure occur. Additional risk factors evaluated by SAM include safety and environmental threats, and threats to effective cost management.

In 2015, SAM completed its initial modeling of the T&D asset base and produced its first, draft risk assessment and Risk Register for the T&D system. In 2016, SAM developed a tool to economically evaluate risk reduction projects. This tool, called the Integrated Planning Tool (IPT), is now available for use by all PGE departments that want to evaluate potential risk reduction projects in the T&D asset base, including the deployment of Smart Grid technologies, which can substantially reduce system risk by shortening outage durations. In 2017, SAM is refreshing all of its models and issuing a revised system risk assessment and Risk Register. SAM is also sponsoring a large number of system risk reduction investment projects.

7.4. Low Income Customer Engagement

It is important that new program initiatives are accessible and meet the needs of all PGE customers. Though PGE does not collect income data from customers, PGE ensures that the needs of economically disadvantaged customers are considered through a variety of efforts in research, program development, outreach, and OPUC engagement. In 2014, PGE conducted focus groups with economically disadvantaged customers to better understand customer awareness of programs and communication preferences. In addition to targeted focus groups, PGE actively monitors themes of "customer voices" via call logs, emails, and other communications employees have with customers. A PGE cross-functional team also facilitates biannual CAA meetings to talk openly about challenges and creative solutions with key community stakeholders. All of these insights collectively help inform how PGE markets and develops programs.

PGE provides CAAs with information and marketing collateral to distribute to customers that educate them about tools available to help them manage their energy use and bills such as Energy Tracker, mobile alerts, Preferred Due Date, and Equal Pay. In addition to providing materials for these organizations, PGE is working to develop programs that respond to the requests of this customer base. Recent focus groups involving lower income customer segments highlighted interest in peak time rebates as a risk-free, non-punitive pricing program. As a result, peak time rebates is being evaluated in the Flex Pricing Pilot. Recently, PGE conducted workshops with CAAs to discuss the fundamentals and benefits of electric vehicles.

Furthermore, PGE has been and will continue to be engaged in the OPUC process to evaluate alternative customer assistance programs.

7.5. Cost Effectiveness

Cost-effectiveness evaluations have been used in energy conservation program design for decades. These evaluations are used to identify benefits and costs associated with programs and energy conservation measures. As PGE is developing a portfolio of distributed energy resources (Demand Response, Energy Storage, Electric Vehicles, Distributed Renewables, Dispatchable Standby Generation, etc.), PGE must have means to evaluate the costs and benefits of new resources to evaluate their benefit to the system, our customers, society, etc. Because each of these DERs is unique in how they provide benefit to the system, PGE has a variety of efforts underway to quantify to determine value streams associated with various types of DERs.

At OPUC's request, PGE held a workshop on April 28th, 2017 to compare cost effectiveness methodologies across all current and future DER and DSM efforts. The workshop was not intended to make a decision on any determination of a "right way" to do cost effectiveness for any particular DER but instead was intended to start a conversation about some of the key considerations and areas of uncertainty for each type of DER. Further, the workshop identified a number of cross-cutting issues across many DERs:

- Choice of cost-effectiveness test
- Duration of analysis
- Input assumptions
- Locational value
- Value of ancillary services
- Value of resilience/reliability
- Equity
- Operation of shared assets (issues around when customer & energy company are operating assets)
- Cost trajectory of new technologies
- Choice of avoided cost resource

The workshop was attended by PUC Staff, ODOE, NWEC, ETO, PacifiCorp, DOJ, and the NW Power & Conservation Council. PGE believes the workshop was a good first step at engaging the right stakeholders for guiding the future of cost-effectiveness of emerging DSMs. PGE looks forward to future conservations on cost-effectiveness. A copy of the presentation from the workshop is included in Appendix 6.

Appendices

Appendix 1. Smart Grid Metrics

Table 22: Asset Optimization Metrics

Metric	2012	2013	2014	2015	2016
% Substations with SCADA	70%	70%	74%	77%	78%
% Critical Transformers w/ DGA	68%	68%	68%	68%	85%
Efficiencies realized through CVR (MWh)	-	356	768	-[5]	
System Risk Holding ($)	*Potential Future metric: Not yet capturing*				
System Risk Mitigated ($)	*Potential Future metric: Not yet capturing*				

Table 23: Reliability Metrics, Corporate Summary

Metric		2012	2013	2014	2015	2016	3-yr Avg.
Including Major Event Days[6]	SAIDI	136	205	245	175	169	196
	SAIFI	0.72	0.57	1.2	0.78	0.79	0.92
	MAIFI	1.1	0.9	1.3	1.2	1.1	1.2
	CAIDI	189	360	204	222	214	213
Excluding Major Event Days	SAIDI	72	61	94	75	97	89
	SAIFI	0.55	0.45	0.7	0.48	0.59	0.59
	MAIFI	1.1	0.9	1.3	1.2	1.1	1.2
	CAIDI	131	138	135	156	163	151
ASAI, CEMI, & CELID		*Potential Future metric: Not yet capturing*					

[5] CVR has been disabled on pilot feeders while communications/analytics pilots are underway

[6] A Major Event Day is a day in which the daily system SAIDI exceeds a threshold value that is computed via the IEEE Standard 1366 (IEEE Guide for Electric Power Distribution Reliability Indices) methodology. This methodology is used by PGE to calculate distribution system performance indices and utilizes the Major Event Day (MED) designation as a basis for evaluation of system performance. The purpose of MED designation is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events. As a result, PGE captures and reports system performance metrics both including and excluding Major Event Days.

Table 24: Reliability Metrics by Region, Eastern

Metric		2012	2013	2014	2015	2016	3-yr Avg.
Including Major Event Days	SAIDI	214	119	279	237	196	237
	SAIFI	0.94	0.69	1.45	1.03	0.88	1.12
	MAIFI	1.64	1.32	1.67	1.58	1.4	1.6
	CAIDI	227	172	193	230	223	215
Excluding Major Event Days	SAIDI	86	75	115	76	92	94
	SAIFI	0.64	0.57	0.83	0.55	0.60	0.66
	MAIFI	1.64	1.32	1.67	1.58	1.4	1.6
	CAIDI	134	133	139	139	152	143

Table 25: Reliability Metrics by Region, Southern

Metric		2012	2013	2014	2015	2016	3-yr Avg.
Including Major Event Days	SAIDI	108	97	224	155	183	187
	SAIFI	0.61	0.45	0.82	0.70	0.85	0.79
	MAIFI	0.6	0.40	0.9	0.9	0.8	0.9
	CAIDI	177	216	273	223	215	237
Excluding Major Event Days	SAIDI	78	47	67	91	132	97
	SAIFI	0.53	0.30	0.40	0.51	0.68	0.53
	MAIFI	0.6	0.40	0.9	0.9	0.8	0.9
	CAIDI	147	157	168	178	193	180

Table 26: Reliability Metrics by Region, Western

Metric		2012	2013	2014	2015	2016	3-yr Avg.
Including Major Event Days	SAIDI	86	400	208	97	124	143
	SAIFI	0.60	0.46	1.08	0.49	0.64	0.74
	MAIFI	0.7	0.70	1.1	0.74	0.9	0.9
	CAIDI	143	870	193	200	194	196
Excluding Major Event Days	SAIDI	61	50	78	64	83	75
	SAIFI	0.51	0.36	0.67	0.37	0.52	0.52
	MAIFI	0.7	0.70	1.1	0.74	0.9	0.9
	CAIDI	120	139	116	178	159	151

Table 27: Energy Storage Metrics

Metric	2012	2013	2014	2015	2016
Available Storage Capacity (MW)	5.00	5.00	5.00	5.00	5.01
Available Storage Energy (MWh)	1.25	1.25	1.25	1.25	1.28
# of Energy Storage Locations	1	1	1	1	2

Table 28: Electric Vehicle Metrics

Metric	2012	2013	2014	2015	2016
Est. Number of Electric Vehicles in Service Area[7]	1,600	4,033	5,500	6,300	8,091

Table 29: Customer Engagement Metrics

Metric		2012	2013	2014	2015	2016
Total # Customers that have utilized Energy Tracker	Residential	79,702	123,508	165,004	201,375	231,777
	Commercial	728	1,440	2,462	3,388	4,138
	Total	**80,430**	**124,948**	**167,466**	**204,763**	**235,915**
Energy Tracker Realized Savings[8]		3%				
# Customer Utilizing Energy Expert		40	101	97	105	108
# of Customer Accounts of TOU Rate Schedule	Residential[9]	2,287	2,313	2,303	2,305	3,592
	Commercial	1,630	1,672	1,794	1,785	1,765
	Industrial	132	131	129	120	133
	Total	**4,049**	**4,116**	**4,226**	**4,210**	**5,490**
# Customers participating in DSG		29	33	34	35	38
Dispatchable capacity of DSG (MW)		79.4	83.4	94.0	106.8	116.9
Capacity of customer-owned renewable (MW)[10]		28.6	35.8	44.5	54.2	73.2
Number of customer programs[11]		6	6	6	6	6

[7] Estimated based on ODOT and Navigant estimates of EVs in Oregon with about 80% in PGE service area
[8] Energy Tracker savings data is based on program evaluation in 2013
[9] Includes customers in Flex Pricing pilot on a TOU rate
[10] Includes solar, wind, hydro, fuel cell, and methane gas. Capacity is reported in MW-AC. Inverter-based technologies (solar and wind) include an 85% DC-to-AC derate factor.
[11] Includes energy information services (Energy Tracker & Energy Expert), demand response (Schedule 77), pricing programs (TOU and TOD), and distributed generation (DSG); Note: Does not include pilots

Table 30: Demand Response Metrics[12]

	Metric		2012	2013	2014	2015	2016
	# Customers participating in DR	Residential[13]	790	596	0	142	16,409
		Business	1	3	27	42	58
		Total	**791**	**599**	**27**	**184**	**16,467**
Winter	Maximum available capacity of DR (MW)	Residential	0.2	0.1	0.0	0.1	1.4
		Business	16.0	17.3	24.6	24.6	14.9
		Total	**16.2**	**17.4**	**24.6**	**24.7**	**16.3**
	Season Peak (MW)		3,597	3,527	3,646	3,914	3,716
	Available capacity of DR (% of season system peak)		0.45%	0.49%	0.67%	0.63%	0.44%
Summer	Maximum available capacity of DR (MW)	Residential	0.1	0.1	0.0	0.0	5.8
		Business	16.0	16.3	21.0	27.4	12.9
		Total	**16.1**	**16.4**	**21.0**	**27.4**	**18.7**
	Season Peak (MW)		3,597	3,527	3,646	3,914	3,726
	Available capacity of DR (% of season system peak)		0.45%	0.46%	0.58%	0.70%	0.50%

Table 31: Customer Engagement Metrics
(% Participation in Each Program Type by Segment, 2016)

Segment	Residential	Business
% Participation in each program type		
Avg. # of Retail Customers[14]	752,365	107,031
Energy Information Services	30.8%	4.0%
Demand Response	2.1%	0.1%
Pricing Program	0.5%	1.8%
Distributed Generation	1.0%	0.6%

[12] Programs covered in the table below include: Critical Peak Pricing, Schedule 77, Energy Partner, Smart Thermostats, and the smart water heater direct load control pilot.
[13] 2012-2013 Residential DR programs include the Critical Peak Pricing Pilot.
[14] PGE 2016 Annual Report: http://investors.portlandgeneral.com/annuals-proxies.cfm

Table 32: Total Number of Smart Meters Deployed [15]
(By Year, Customer Type)

Customer Type	2012	2013	2014	2015	2016
Residential	744,392	752,668	760,932	756,063	764,401
Commercial	113,149	114,400	115,197	102,228	103,395
Industrial	4,790	4,751	4,707	3,951	3,913
Total	**862,331**	**871,819**	**880,836**	**862,242**	**871,709**

Table 33: AMI Complaints and Opt Outs
(By Year, Customer Type)

Metric	2012	2013	2014	2015	2016
# Customer Complaints about AMI[16]	133	118	136	94	62
Cumulative # Customers Choosing No AMI	4	9	15	22	10

[15] Prior to 2015, reported values include 'virtual' meters which are used in the system for complex billing calculations (i.e. Solar Payment Option & Net Metering customers).
[16] Number of customers initiating a request to opt out of AMI

Appendix 2. Summary of All Smart Grid Initiatives

Table 34: Summary of All Smart Grid Initiatives

Initiative	Status	Page
Advanced Metering Infrastructure	Complete	31
Automated Generation Control	Complete	32
Bulk Thermal Storage	Future Initiative	71
Communications Upgrades	Active Deployment	31
Conservation Voltage Reduction	Pilots & Evaluation	38
Customer Battery Back-Up System	Research	43
Customer Information System	Planned Deployment	33
Demand Response: Energy Partner Pilot	Pilots & Evaluation	45
Demand Response: Firm Load Reduction (C&I)	Active Deployment	45
Demand Response: Multi-family Water Heater	Planning Pilot	47
Demand Response: Smart Thermostat Pilot	Pilots & Evaluation	46
Demand Response: Smart Water Heaters	Pilots & Evaluation	48
Dispatchable Standby Generation (DSG)	Active Deployment	42
Distribution Automation	Pilots & Evaluation	38
Distribution Management System (DMS)	Future Initiative	72
Distribution Temperature Sensing	Limited Deployment	40
EMS State Estimator	Limited Deployment	32
Energy Expert	Active Deployment	35
Energy Management System	Complete	32
Energy Storage	Planning	37
Energy Tracker	Active Deployment	34
EV: Electric Mass Transit	Future Initiative	69

Initiative	Status	Page
EV: Employee EV Research Project	Research	50
EV: EV-only TOU rate (sub-metered)	Complete	49
EV: Public Charging	Limited/Future Initiative	52,69
EV: Smart Charging (Workplace EV Demand Response)	Research	51
EV: Vehicle to Grid	Research	52
Fault Detection (Distribution)	Pilots & Evaluation	39
Geographical Information System	Complete	33
Meter Data Management System	Planned Deployment	33
Microgrid (Fire Station Demonstration Project)	Planning	42
Outage Management System	Complete	32
Prepaid Metering	Future Initiative	72
Pricing Program: Critical Peak Pricing	Complete	55
Pricing Program: Flex Pricing Research Pilot	Pilots & Evaluation	44
Pricing Program: Time-of-Day Pricing	Active Deployment	43
Pricing Program: Time-of-Use Pricing	Active Deployment	43
Real-time Contingency Analysis	Limited Deployment	32
Remedial Action Schemes/Special Protection Schemes	Limited Deployment	40
Research & Development	Research	56
Salem Smart Power Project	Complete	54,55
SCADA	Active Deployment	36
Smart Cities	Future Initiative	73
Smart Inverters	Future Initiative	70
Solar Energy Grid Integration Systems (SEGIS)	Complete	54
Strategic Deployment of Distributed Energy Resources	Future Initiative	71

Appendix 3. Research, Development, and Pilot Summary

Table 35: Research, Development, and Pilot Summary

Initiative	Status	Page
T&D Analytics	Pilots & Evaluation	34

Description:

PGE has built systems that utilize smart meter data for a variety of T&D operational improvements, such as overloaded transformer analysis which helps identifying opportunities for proactive equipment replacement. These tools help avoid potential feeder downtime and customer outages.
Additionally, PGE has begun an advanced analytics pilot program to leverage the massive amounts of new data available via IEDs on the T&D system. This pilot project is utilizing existing data streams, such as AMI data, to produce actionable information required to enhance planning and operations activities on PGE's T&D system. The system will help PGE develop use cases for leveraging real-time data streams to improve operational efficiencies.

Benefits:	Cost:
Operational Efficiency: The system will help PGE develop use cases for leveraging real-time data streams to improve operational efficiencies.	2017 Budget: $185,000

Initiative		Status	Page
Distribution Automation (DA)		Pilots & Evaluation	38
Description: DA refers to a distribution system that has the ability to automatically locate and isolate faulted feeder sections, and subsequently restore service to un-faulted feeder segments. DA systems are capable of automatically isolating faulted line segments and restoring power to other customers on the feeder within minutes. In the past, those customers were sometimes out for several hours. The DA system can be monitored and controlled via SCADA. PGE deployed a DA pilot at Gales Creek in 2012. DA has resulted in operational savings and System Average Interruption Duration Index (SAIDI) reductions for customers served by the Gales Creek system.			
Benefits: Improved reliability: DA systems are capable of automatically isolating faulted line segments and restoring power to other customers on the feeder within minutes. In the past, those customers were sometimes out for several hours.	*Cost:* Approximately $ 200,000 - $ 500,000 per feeder (varies based on feeder configurations).		
Conservation Voltage Reduction (CVR)		Pilots & Evaluation	38
Description: CVR is the strategic reduction of feeder voltage, deployed with phase balancing and distributed voltage-regulating devices to ensure end-customer voltage is within the low range of ANSI (American National Standards Institute) acceptable voltages (114V – 120V). PGE completed feasibility studies and two CVR pilot projects in 2014 at Hogan South substation in Beaverton and Denny substation in Gresham. By reducing voltage 1.5% - 2.5% in the pilot project, PGE was able to reduce customer demand (MW) and energy consumption (MWh) by 1.4% - 2.5%.			
Benefits: Customer Energy Savings: The pilot yielded 1.5%-2.5% customer energy savings (totaling 768 MWh in 2014). Present value of system benefits: $ 2,530,945 (2-feeder pilot) Additionally, 94 transformers have been identified as CVR candidates (customer energy savings potential of 16 aMW).	*Cost:* Present value of system costs: $ 671,872 (2-feeder pilot)		

Initiative		Status	Page
Fault Detection (Distribution)		Pilots & Evaluation	39
Description: A pilot is underway in which Faulted Circuit Indicators (FCIs) have been installed on one feeder. The data created by the FCIs are integrated via AMI communications infrastructure. PGE is monitoring the test case for the FCIs and will evaluate the cost-benefit of the FCI deployment and determine whether or not to invest in FCIs for more feeders along with necessary server upgrades. The Company anticipates the pilot should result in improved reliability metrics. If this single feeder pilot does not provide sufficient data and resources become available, FCIs will be installed on four additional feeders. If the pilot is successful, a strategic deployment of FCI infrastructure could occur starting in 2018.			
Benefits: Improved fault detection & improved reliability: FCI information can help crews restore power faster and likely to lead in fewer truck rolls.	*Cost:* Approximate pilot Cost: $ 200,000		
Synchrophasors on Transmission System		Pilots & Evaluation	39
Description: Synchrophasors provide enhanced system situational awareness for transmission operators and planners by providing real-time system information. Phasor measurement units (PMUs) capture data at a higher resolution than typical grid monitoring devices and include more depth of information beyond voltage and frequency, including GPS, and time stamped phasor quantities. PGE is strategically deploying PMUs and PDCs at critical transmission facilities to realize these benefits. To date, PGE has deployed synchrophasor technology at 1 transmission substation (Rosemont). In addition to PMU and PDC installation in the field, PGE has invested in critical server infrastructure and software that will enable the Company to realize the maximum benefits of this technology.			
Benefits: (1) Enhanced situational awareness, (2) Improved visibility into interconnection points with adjacent utilities and regional flowgates, (3) Detailed post-event analysis, (4) Generation model validation & test avoidance (reduced down time of generation facilities), (5) System model validation	*Cost:* Estimated budget for installation at five substations and IT infrastructure required: $ 418,714		

Initiative	Status	Page
Customer Battery Back-Up System	Research	43

Description:

The project objective is to minimize the cost of adding storage to the grid by combining both utility and customer value propositions. In collaboration with Portland State University (PSU), PGE has advanced their laboratory prototype to a field battery/inverter system (BIS) prototype demonstration in June 2016. The field prototype is 8kW/30kWh.
In 2017, PGE will install a 2nd customer battery back-up system in 2017. The 2nd system will sited at an employee's home who has a net metered solar array. The 15.5-kWh battery allow the company to test evaluate a 2nd storage technology as well as a use case with solar integration (to extend customer backup power).

Benefits:	Cost:
The project serves to test end-to-end controls and equipment specifications required to utilize a BIS to provide backup power for an entire home during an outage, but at other times, to serve numerous use case such as a resource to serve peak demand, storing excess wind energy at night, and aiding renewables integration in general.	2017 Estimated Budget: $130,000

Initiative	Status	Page
Flex: Pricing Research Pilot	Pilots & Evaluation	44

Description:

In 2014, PGE began a strategic effort to evaluate pricing program types and barriers to customer participation. PGE completed market research that included surveys and focus groups to help inform a pilot offering. PGE also leveraged AMI data to conduct load segmentation research, identifying 5 load profiles that can be targeted for demand response and pricing initiatives. A pilot to test various pricing program types was approved with deferred accounting on June 15, 2015 (Docket No. UM 1708, Order No. 15-203). The pilot will test various pricing program types to identify which ones offer the best customer experience and the greatest system benefit.

Benefits:	Cost:
The pilot will inform which type of pricing program(s) offer the best customer experience and greatest system benefit. The primary expected benefits include reduced peak demand and ability to shift/curtail customer loads.	2017 Budget: $ 707,427

Initiative		Status	Page
Energy Partner		Pilots & Evaluation	45
Description: PGE launched the Energy Partner automated demand response (ADR) pilot for commercial and industrial customers in 2013. It uses automated controls to enable participating customers to respond to event signals within as little as 10 minutes. The pilot is available to customers with 30kW of demand or higher. The program was capable of 11.5 MW in Winter 2015-2016 and will likely have 14 MW available for Summer 2016.			
Benefits: The primary expected benefits include reduced peak demand and ability to shift/curtail customer loads.	*Cost:* 2017 Budget: $ 681,055		
Smart Thermostat Demand Response Pilot (Rush Hour Rewards)		Pilots & Evaluation	46
Description: In 2015, PGE filed a request for deferred accounting (Docket No. UM 1708, Order No. 15-203) to launch a residential smart thermostat direct load control (DLC) pilot which leverages internet-connected smart thermostats as a demand response asset. The pilot launched with Nest in the winter of 2015 (Nest's first winter DR program). The pilot features a bring-your-own-thermostat design making it a great opportunity for our customers who have already taken steps to be more energy efficient, to also find a simple, easy way to shave their peak energy usage. Customers with heat pumps, electric resistance heat, or central air conditions are eligible to participate. Participants receive $25 for signing up and $25 for each program season (2/year).			
Benefits: The primary expected benefits include reduced peak demand (estimated to be about 1-kW per customer) and ability to shift/curtail customer loads.	*Cost:* 2017 Budget: $ 571,478		

<table>
<tr><th>Initiative</th><th>Status</th><th>Page</th></tr>
<tr><td>Multi-Family Water Heater Pilot</td><td>Pilots & Evaluation</td><td>47</td></tr>
<tr><td colspan="3">Description:

In April 2017, PGE submitted a deferral request to implement water heater demand response pilot targeting multifamily residences. The program pilot would run through the end of 2019 and targets 8,000 water heaters over the 30 month pilot.

This program would work with property managers to target large multifamily complexes to enroll in direct load control of existing and new smart water heaters. Two-way communicating switches would be used for existing water heaters and, where appropriate, PGE would help buy down the cost to upgrade old water heaters to new, smart water heaters capable of connecting to a communications module.

PGE has engaged with vendors and, pending commission approval, will go into the field in Q4 of 2017. We will be conducting an ongoing process and impact evaluation of the program and will share evaluation reports at the end of each program year.</td></tr>
<tr><td>Benefits:

The 2016 Integrated Resource Plan identifies significant cost-effective demand response in the existing water heater market.</td><td colspan="2">Cost:

2017 Budget: $ 769,125</td></tr>
<tr><td>Smart Water Heater Pilot with BPA</td><td>Pilots & Evaluation</td><td>48</td></tr>
<tr><td colspan="3">Description:

PGE has conducted a “smart” water heater demand response demonstration using “off-the-shelf” water heaters in 14 employee homes in 2016. The pilot demonstrated a reduction in system peak of about 0.35 kW and the ability to regularly shift about 1.5 kWh of energy use to a period when power costs are lower.

PGE used this experience to inform the development of a regional pilot with BPA with 8 participating utilities. The pilot targets 120-200 PGE residential customers who have installed a communications module that “plugs” into their electric water heater (no electrician is required for the installation). The communication module provides a hybrid communication method: control signals are broadcast using a FM radio station, while return information is collected over the Internet using the customer’s Wi-Fi network.</td></tr>
<tr><td>Benefits:

The will implement various control strategies so as to quantify peak load reductions, and quantify load shifting capability per tank (i.e. reduce load in evening to shift consumptions to night [store wind], or reduce load in morning to shift consumption to midday [store solar]). The pilot will also test customer acceptance of frequent load control without notice.</td><td colspan="2">Cost:

Estimated 2017 Budget: The BPA project budget is approximately $1.5M. PGE’s estimated contribution for 2017 is $20,000 and Staff time.</td></tr>
</table>

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<tr><th colspan="2">Initiative</th><th>Status</th><th>Page</th></tr>
<tr><td colspan="2">Fire Station Microgrid</td><td>Demonstration</td><td>42</td></tr>
<tr><td colspan="4">Description:

In 2016, PGE, ETO, and PUC Staff participated in the Rocky Mountain Institute’s e-Lab Accelerator program to discuss opportunities for solar plus storage microgrids. Though not a participant in the program, the City of Portland is eager to demonstrate energy storage to support their resiliency efforts, to create a training tool for emergency response, and to reduce facility operating costs. In October, 2016, PGE’s Renewable Development Fund awarded the City of Portland a $89,959 grant towards the cost of a solar plus storage single site microgrid at Fire Station #1 in downtown Portland. The City intends to use the funds to install a 30 kW solar array and 60-120 kWh/30 kW battery to create a microgrid at the fire station. The anticipated construction for the facility is Q3, 2017.</td></tr>
<tr><td>Benefits:

PGE is working with the City to scope the project and plan for interconnection. PGE hopes to offer an incentive to the City for control of the battery to call demand response. The City will use the storage for back-up, demand charge optimization, and training.</td><td colspan="3">Cost:

RDF Grant Amount: $89,959</td></tr>
<tr><td colspan="2">EPRI Program P94: Energy Storage & Distributed Generation</td><td>Research</td><td>58</td></tr>
<tr><td colspan="4">Description:

EPRI research programs bring together an EPRI program manager/subject-matter-expert and a network of peer utilities around a common technology, issue, or idea. As a participant, PGE influences the direction of the research conducted by EPRI, networks with other utilities doing similar work, and gets access to technical research and reports throughout the study.
Energy storage and distributed generation technologies are attracting increasing interest from utilities and regulators as localized flexible grid assets. Storage can act as a buffer between electricity supply and demand, increasing grid flexibility and allowing greater accommodation of variable renewable resources. Distributed generation (DG) entails the production of power at or near load centers, thereby augmenting or substituting electricity infrastructure with DG fuel infrastructure, where appropriate. Both storage and DG may provide temporary solutions for regional and local capacity shortages, and may provide relief to localized transmission and distribution congestion.</td></tr>
<tr><td>Benefits:

Better understanding of technical and economic challenge related to the use of utility-scale storage and distributed generation; understanding of effects of storage on the power delivery network</td><td colspan="3">Cost:

2017 Budget: $ 95,000</td></tr>
</table>

<table>
<tr><th>Initiative</th><th>Status</th><th>Page</th></tr>
<tr><td>EPRI Program 174: Integration of Distributed Energy Resources</td><td>Research</td><td>58</td></tr>
<tr><td colspan="3">Description:

EPRI research programs bring together an EPRI program manager/subject-matter-expert and a network of peer utilities around a common technology, issue, or idea. As a participant, PGE influences the direction of the research conducted by EPRI, networks with other utilities doing similar work, and gets access to technical research and reports throughout the study.
Increased distributed energy resources (DER) in the electric grid create a number of challenges. Utilities may face large numbers of interconnection requests; distributed generation on some circuits will exceed the load; and many operating challenges involving feeder voltage regulation, hosting capacity limits, inverter grid support and grounding options are brought to bear. Furthermore, providing reliable service as DER penetrations increase and electricity sales diminish can also add economic and business challenges to the technical ones.
This EPRI Research Program addresses these challenges with project sets that assess feeder impacts, inverter interface electronics, and integration analytics, and evaluates case study experiences and strategies related to future business impacts. It also evaluates leading industry practices for effective interconnection and integration with distribution operations.</td></tr>
<tr><td>Benefits:

These tools and research will aid in maintaining high reliability despite increasing penetration of DERs. These tools will improve feeder-operation analysis with different levels of DERs, integration of distributed resources into distribution planning, and will inform strategies for managing and integrating customer-sited renewable generation.</td><td colspan="2">Cost:

2017 Budget: $ 40,000</td></tr>
<tr><td>EPRI P173: Bulk Power System Integration of Variable Generation</td><td>Research</td><td>59</td></tr>
<tr><td colspan="3">Description:

Much of the estimated development of renewables comprises variable resources such as wind generation and solar photovoltaics (PV), which when integrated with the grid, create new challenges for maintaining reliable system operation. Future projections are that a more significant build-out of these variable renewable resources is likely at both the transmission and distribution levels. Power system planners and operators will require new tools and resources to ensure a reliable, sustainable, and cost-effective supply of electricity to consumers.

Research is focused on -(1) The Bulk Power System Variable Generation Integration research program which provides variable generation integration analytics; (2) development of planning and protection methods, tools, and models; and (3) development of operator methods and tools to reliably and economically integrate wind and solar PV generation.</td></tr>
<tr><td>Benefits:

Will provide engineers access to research that will help effectively integrate renewable energy into PGE's grid without compromising reliability.</td><td colspan="2">Cost:

2017 Estimated Budget: $70,000</td></tr>
</table>

Initiative	Status	Page
EPRI P183: Cyber Security	Research	59
Description: This program develops an analysis framework to correlate cyber, physical, and power system events including: • Development of security event scenarios that utilities can adapt to their operational environment • Identification of operational and asset condition data sources to support event detection; and • Results and lessons learned from testing and demonstrating scenario detection in EPRI's lab as well as utility host sites.		
Benefits: This project intends to focus the "Analysis" component of the Integrated Threat Analysis Framework by developing and testing broadly applied use cases and potential data analysis methods to determine when a malicious event has taken place. Participating in this program will help PGE prevent and avoid cybersecurity attacks.	*Cost:* 2017 Estimated Budget: $95,000	
EPRI Program 180 – Distribution Systems	Research	60
Description: The Program delivers a portfolio of tools and technologies to increase overall distribution reliability and resiliency; understand the expected performance for specific components throughout its life cycle; assess methods for evaluating the condition of system components; and develop and test new technologies. The program delivers a blend of short-term tools such reference guides and industry practices as well as longer-term research such as component-aging characteristics and the development of new inspection technologies. Overall, the Program includes research that supports grid modernization and provides tools for planning, design, construction, maintenance, operation, and analysis of the distribution system.		
Benefits: Will provide engineers access to research that will help effectively modernize the grid and increase system reliability.	*Cost:* 2017 Estimated Budget: $170,000	

Initiative	Status	Page
EPRI Power Quality Knowledge Development and Transfer	Research	61

Description:

Management of electrical power quality issues has never been an easy task, but it has grown even more difficult with deregulation, reregulation, increasingly scarce technical and strategic tools, and a conspicuous lack of unbiased resources for information, collaboration, advice, and problem solving. Moreover, with the ever-increasing use of sensitive digital and electronic equipment in today's economy, PGE's end-use customers are not only demanding higher quality power, but also are calling upon it to help resolve PQ problems within customer facilities. This research will provide PGE access to experts and industry peers, access to high-impact resources (such as documents covering a wide range of PQ topics), and access to more than 500 PQ case studies, PQ technical documents, PQ standards references, indexes, conference presentations, and a wealth of other resources.

Benefits:	Cost:
The project will provide access to power quality research and industry experts—this information will equip our engineers with tools to ensure we meet our customers' growing power quality needs.	2017 Estimated Budget: $20,000

Initiative	Status	Page
WSU Power Engineering Energy Innovation Center Data Access	Research	62

Description:

Washington State University's ESI Center brings together research faculty, business leaders, and governmental organizations to address the technological challenges inherent in the demand for renewable, clean and reliable energy. The center consists of more than 30 WSU faculty members. Thirteen are in the core areas of power, energy, and computer science. More than twenty are in sociology, economics, psychology, communication, and public policy - helping bridge the gap between science and society. The center also collaborates with a wide range of government and industry partners. The center's focus areas include renewable energy; social and economic incentives; information collection, delivery, and analysis; decision support; efficient use of right-of-way and associated economic issues; and cyber security of the smart grid. Many of these topics are of interest to PGE especially in light of Oregon's SB 1547 mandate for PGE to achieve 50% renewable power by 2040.

Benefits:	Cost:
PGE participation in ESI can lead not to just data and information access but also to collaborative research that is co-funded by larger granting institutions such as the US DOE.	2017 Estimated Budget: $15,000

Initiative	Status	Page
PSU - Non-Wires Solutions to Transmission Congestion	Research	63

Description:

It is well known that the Pacific Northwest transmission grid is congested. This is particularly true of east-west electricity movement but also in localized areas. The congestion has grown over the years due to load center growth on the west side of the Cascade Mountains and the proliferation of wind power plants on the east side of the mountains. As the Bonneville Power Administration (BPA) controls 75% of the region's transmission system this is a top of mind concern. Since PGE has a heavy reliance (as do virtually all electric utilities in the region) on the BPA system it is also of import to the Company and its customers.

The advent of large grid-scale energy storage systems of which PGE's Salem Smart Power Center is an example suggests the possibility of a non-wires option to help relieve transmission congestion. Energy storage can effectively serve as a "wide spot" in the pipe and with a sufficient number of installations could eventually widen the pipe entirely and be a viable solution to the congestion issue. PGE in collaboration with Portland State University proposes a competent and authoritative research paper to set context and to analyze this possibility in light of recent energy storage advances.

Benefits:	Cost:
The research study will yield insights into non-wires alternatives to transmission congestion, which could yield cost savings in addressing transmission constraints in the future.	2017 Estimated Budget: $20,000

Initiative	Status	Page
OSU - Cascadia Lifelines Research	Research	64

Description:

The Cascadia Lifelines Program provides essential and unique engineering solutions for our lifeline providers, including cost-effective retrofit strategies for infrastructure subjected to long-duration shaking resulting from a Cascadia Subduction Zone event. The project provides improved prediction of ground-shaking specific to Oregon conditions, predicted seismic behavior of soils unique to the Willamette Valley including the liquefaction potential, and system optimization of interdependent lifelines.

In joining this program effort headed by Oregon State University PGE continues taking a pro-active approach in minimizing the impact of the next devastating earthquake on its customers, and doing its part in improving Oregon's ability to bounce back from such an event. As a secondary benefit, teaming with OSU on this research will foster collaboration between OSU and PGE, and give PGE ready access to the team of seismic hazard mitigation experts at the university. R&D funding is $50,000 per year for a 5-year commitment or $250,000 over five years; PGE occupies a seat on our management board that guides the OSU research priorities. The dollar commitment on behalf of PGE customers is substantial as is the match from other utility and related infrastructure providers (e.g., BPA, ODOT, NW Natural, EWEB, Port of Portland and others) will be matched five to 10 fold.

Benefits:	Cost:
The impact of this research will help assess cost-effective approaches to increased resilience, resulting in saved lives and improved business continuity for western Oregon and PGE's service territory.	2017 Estimated Budget: $50,000

Initiative	Status	Page
OSU Wave Energy Support	Research	64

Description:

PGE continues its support of OSU to develop and test intermediate/full scale wave energy generation devices in the Wallace Energy Systems and Renewables Facility (WESRF) Lab (linear test bed), Hinsdale wave flume, and/or Northwest National Marine Renewable Energy Center (NNMREC) open ocean test berth – Pacific Marine Energy Center (PMEC).

Benefits:	*Cost:*
The study will provide access to data analysis on wave energy. The study also aims to demonstrate and expand the available renewable resources for PGE customers	2017 Estimated Budget: $25,000

Initiative	Status	Page
Inspection and Correction – Below Grade Corrosion	Research	65

Description:

PGE is very interested in developing an inspection and correction program that facilitates learning more about below grade corrosion for its galvanized lattice towers, galvanized tubular steel poles and weathering steel tubular steel poles. The research should also include a survey of industry best practices. Presently, the Company has very little experience with evaluating the below grade condition of its steel structures.

Research will include the efficacy of mitigation as well as correction methods including: below grade coatings, ground sleeves, grounding techniques, and cathodic protection. PGE has been in discussions with Oregon State University School of Engineering to craft a potential research agenda and attendant scope of work. It is likely that BPA will also find this research valuable and may also contribute funds to expand the work (e.g., different soil types, tower designs, etc.)

Benefits:	*Cost:*
By better understanding below grade corrosion on PGE's system, engineers will be able to proactively improve the structural integrity of the system, reduce system risk, and increase system reliability.	2017 Estimated Budget: $60,000

Initiative	Status	Page
Real-time Load Modelling Synchrophasor Network, Microgrid Reliability	Research	66

Description:

The goal of this project is to better understand load models in order to advance protection of the next generation (integrated grid) power transmission and distribution infrastructure. With assistance from the growing PMU network at OSU, a composite dynamic load model can be estimated in real time and provide useful insight into the design of microgrid protection schemes. This will address challenges such as reverse flows, automatic reclosing, or delayed relay tripping. This project will provide PGE and its customers with insights about the benefits of deploying phasor measurement units (PMUs) at the distribution level yielding improved analysis of anomalies from modern, non-traditional loads, as well as synchronization between transmission and distribution level sensing.

Benefits:

The pilot will improve PGE's situational awareness of the system and inform how synchrophasors may be used to support microgrid reliability.

Cost:

2017 Estimated Budget: $30,000

Initiative	Status	Page
U of O, Regional Solar Radiation Data Center Project	Research	66

Description:

This project supports the University of Oregon's longstanding collection and storage of regional solar energy data and the maintenance of calibration equipment. This data is supplied to the U. S. Department of Energy's National Renewable Energy Laboratory (NREL) and made available to all Utilities for siting of Utility scale solar projects. The calibrated solar instrumentation can also be used to validate PGE's present and future distributed solar photovoltaic (PV) resources performance; ancillary meteorological data will be used to estimate effects of wind on distributed PV solar resources.

Benefits:

They study will better inform PV solar generation forecasts (factoring in meteorological data, wind, etc.).

Cost:

2017 Estimated Budget: $10,000

Initiative	Status	Page
CTA-2045 EPRI demo of Smart water heaters & 240V EV Chargers	Research	67

Description:

EPRI has convened a group of utilities, e.g. Duke, Southern Company, AEP, BPA, TVA, appliance manufacturers; for PGE: water heaters and electric vehicle supply equipment (EVSEs) and communication device makers to conduct field demonstrations targeting 10 units of each type of appliance; mostly at employee homes. The goal is to advance end-to-end capability of demand response (DR) using the CEA-2045 communication interface (also known as the appliance socket.) This is a three phase effort beginning with project planning in 2013. Projected field deployment and demonstration starts between mid-2014 to early-2015. Non-EPRI program follow up and evaluation in 2016. With this proposal PGE intends to test demand response (DR) with hot water heaters and EVSEs. Expected benefits to PGE include: (1) Influence the demand responsive behavior of appliances (by providing requirements to manufacturers thru EPRI); (2) Advance efforts that PGE proposed it would pursue as part of PGE's Integrated Resource Plan (IRP) and in PGE Smart Grid reports to OPUC and finally, (3) Advance or otherwise support PGE's Retail Market Strategy to provide innovative solutions for PGE customers.

Benefits:	Cost:
The CEA-2045 communication interface has the potential to reduce the cost of widespread water heater and EVSE demand response.	2017 Estimated Budget: $60,000

Initiative	Status	Page
NuScale Modular Reactor Study Group	Research	67

Description:

PGE has the opportunity to assess the development and potential commercialization of the NuScale small modular reactor technology. PGE staff will do this by being part of a regional study and advisory group that has been assembled to periodically review developments regarding technical and licensing advances.

Benefits:	Cost:
This effort allows PGE to participate with other stakeholders to collaborate on how as NuScale Energy looks at how they can deploy Small Modular Reactors at US sites in the future.	2017 Estimated Budget: $5,000

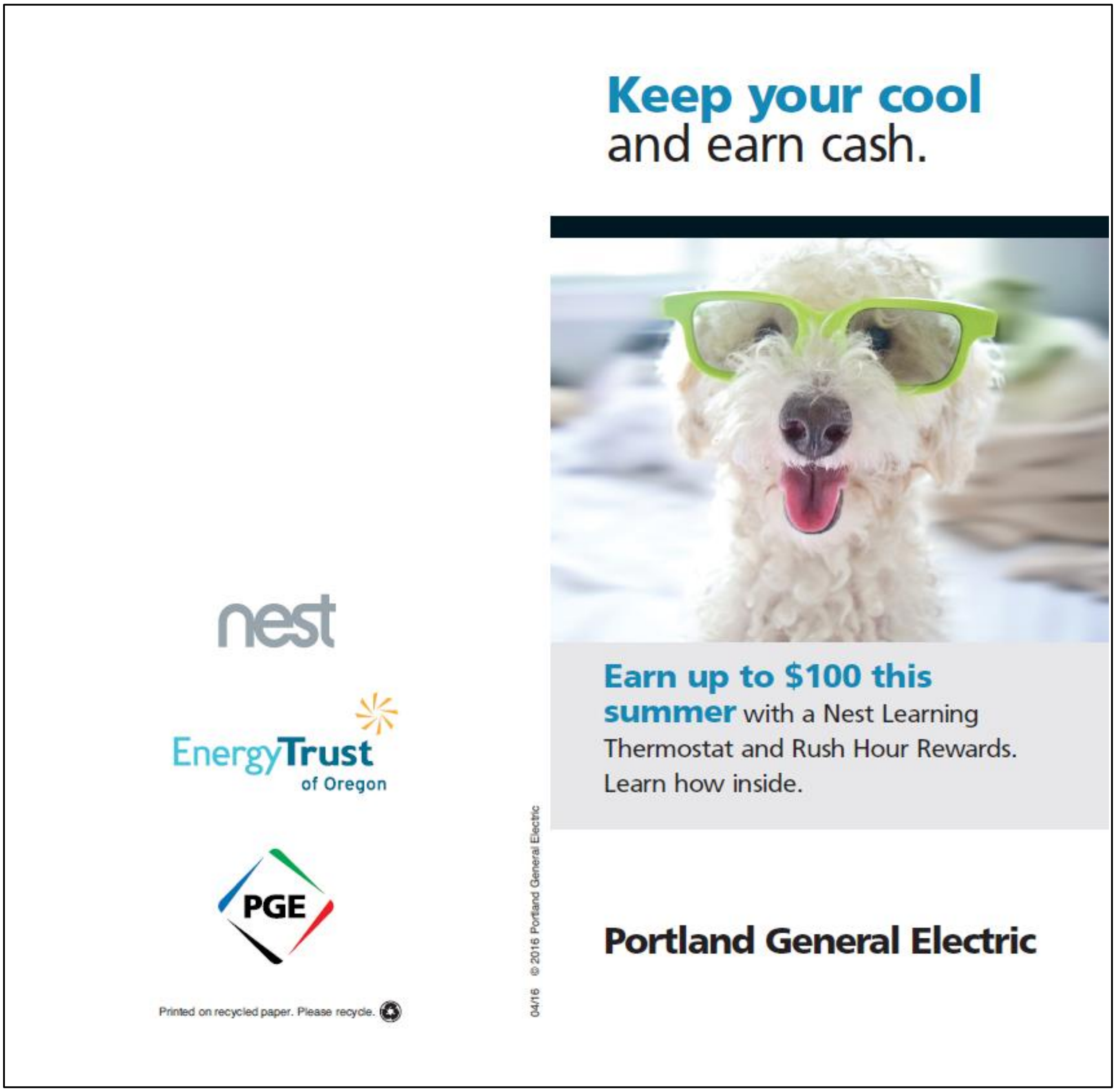
Initiative		Status	Page
PGE Employee EV Charging Behavior Research		Research	68
Description: With the increased penetration of electric vehicles (EV) and supporting infrastructure -- PGE needs to research various concerns as this use ramps up; in particular attempt to understand: • charging and driving habits of EV customers • battery life & degradation as it relates to a driver's charging & driving habits • impact of TOU rate schedule on EV charging • commuting habits of EV drivers PGE has pursued this research via studying the driving habits and usage of PGE employees as part of this R&D project.			
Benefits: By better understanding charging/driving habits, impact of TOU rate schedule on EV charging, and the community habits of EV drivers, PGE will be better positioned to develop transportation electrification pilots that encourage efficient grid utilization while maintaining a positive customer experience.	*Cost:* 2017 Estimated Budget: $170,000		
Biomass Supply Chain Development in Support of Boardman Conversion		Research	68
Description: Since 2009, PGE has investigated the potential to use torrefied biogenic biomass to displace coal at its Boardman Power Plant. This has been coupled to the need to pre-process the biomass through torrefaction in order to make the fuel sufficiently friable (crispy) so that it can be ground to a fine powder in the Boardman pulverizers. PGE has done early exploration in partnership with OSU Extension into a biomass supply chain via energy grass agronomy especially for Arundo and Sorghum. In 2016, PGE worked with Oregon Torrefaction, LLC to explore the availability of woody biomass derived in part, from USFS Forest Stewardship contracts out the Malheur National Forest. As Boardman gets closer to its commitment to cease use of coal at the end of 2020; PGE will need to firm its views of what will be the potential biomass supply chain components sufficient to fire the Plant at 30% to 40% capacity.			
Benefits: Developing a supply chain for biomass to fuel Boardman plant could create a unique resource to aid in meeting long-term RPS targets.	*Cost:* 2017 Estimated Budget: $100,000		

Initiative		Status	Page
Torrefied Biomass Fuel Test Burns for Multiple Days - Proof of Concept		Research	68
Description: Since 2010, PGE has embarked formally on a large R&D effort to assess the feasibility of displacing coal at its Boardman pulverized coal plant with torrefied biomass. This project extends that effort with work to fine tune both the production and the use of the new fuel in the Plant's boiler. The project will also support evolution of new fuel handling, processing and safety procedures associated with both green and torrefied biomass. The project will also closely monitor torrefied fuel performance and emissions in both co-fire, as a transition, and 100% torrefied biomass applications.			
Benefits: Ensuring that the Boardman plant can effectively generate electricity from burning biomass could be beneficial in meeting long-term RPS targets.	*Cost:* 2017 Estimated Budget: $433,293		
Yamhill County Landfill Gas Potential for Renewable Power Generation		Research	68
Description: PGE will participate in R&D consortium with Volta power to investigate potential of landfill gas in Yamhill County. This project will test the capability of a small engine on various types of landfill gas. The potential for using this gas for renewable power generation in Oregon will also be investigated.			
Benefits: The tests will help determine whether or not landfill gas is a viable resource to help meet RPS goals in Oregon.	*Cost:* 2017 Estimated Budget: $5,000		

Appendix 4. Marketing and Outreach Materials

Rush Hour Rewards

ETO Bill Insert (Outside):



ETO Bill Insert (Inside):

Stay cool this summer **and earn cash three ways.**

PGE has teamed up with Nest and Energy Trust of Oregon to help you save energy and get rewarded at the same time. If you have central air conditioning or a ducted heat pump, and install a Nest Learning Thermostat, you could save three ways:

1. The Nest Thermostat programs itself and **can help you save energy.**[1]
2. When you install a Nest, you may also qualify for a **$50 cash-back incentive** from Energy Trust.[2]
3. Sign up for **Rush Hour Rewards** and earn up to $50 from PGE this summer, plus more each year.

Get started at **PortlandGeneral.com/Nest**

PGE EnergyTrust of Oregon nest

What's Rush Hour Rewards?

PGE will pay you to use less energy when everyone else is using more. And your Nest Thermostat can do it automatically.

Here's how it works

- PGE wants to **lower demand** during energy rush hours, like those hot summer afternoons when everyone's cranking up the thermostat.
- The Nest Thermostat can help you **use less energy** by tweaking the temperature ahead of time up to three degrees during the rush hour.
- **You're in control.** If you're home, Nest won't let it get too hot. But if you start to feel warm, you can change the temperature at any time.

1 Independent studies showed that the Nest Learning Thermostat saved people an average of 10-12% on heating bills and 15% on cooling bills. Based on typical energy costs, Nest estimates average savings of $131 to $145 a year. Actual savings will vary.

2 See EnergyTrust.org/Thermostat for eligibility details

Keep Cool E-Mail:

Earn up to $125 this summer

Pair a Nest Learning Thermostat with Rush Hour Rewards from PGE and cash back from Energy Trust of Oregon

If you have central air conditioning or a ducted heat pump, and install a Nest Learning Thermostat, you could:

1. **Save energy** — the Nest learns your preferences to help you save.[1]
2. **Get $50 cash back** from Energy Trust.[2]
3. **Earn up to $50 from PGE this summer**, plus more each year, when you sign up for Rush Hour Rewards.

Learn More

Get a Nest for Less Email:

PGE

Forward:

Get a Nest for less.

Then, keep your cool & earn cash.

When you pair a Nest Learning Thermostat with Rush Hour Rewards from PGE and cash back from Energy Trust of Oregon, you'll save all summer long:

1. Through July 4, get $50 off a Nest Learning Thermostat at Nest.com and participating retailers. The Nest learns your preferences to help you save.[1]
2. You may also qualify for $50 cash back from Energy Trust.[2]
3. Then, earn up to $50 from PGE this summer, plus more each year, when you sign up for Rush Hour Rewards.[3]

Learn More

Energy Partner

Energy Partner Fact Sheet

Portland General Electric

Energy Partner^{SM} Fact Sheet

What Energy Partner is

Energy Partner is a demand response program: PGE will pay customers to shift or reduce electricity use during periods of high demand for power, such as hot summer afternoons and cold winter mornings.

Reducing demand during peak times enables PGE to avoid the cost of building additional generation plants and pass the savings on to customers.

PGE has hired demand response industry leader EnerNoc, Inc. to manage the program within our service territory. EnerNoc works closely with customers to create a customized energy reduction plan and install the equipment that allows customers to participate.

Program participants can be called upon to reduce energy usage during a demand response event. Energy Partner events are limited to the following seasons and times:

- Winter Season – from December to February
  - Events can occur between 6 and 11 a.m. or 4 and 9 p.m.
- Summer Season - from July to September
  - Events can occur between noon and 10 p.m.

What Energy Partner is not

Energy Partner is not a mandatory program. Joining is optional and enrolled customers aren't required to participate in every event.

PGE does not take control of the customer's power. The customer is always in control and the amount nominated for reduction is determined by a conversation and agreement between the customer and EnerNoc.

What to consider

- Control systems in place or in development
- 1st, 2nd, or 3rd shift operations
- Onsite equipment
- Ideal industries:
  - Food Processing
  - Cold Storage
  - Water Treatment Plants
  - College or Universities

Basic Criteria for Customer Enrollment

- Overall load ≥ 200 kW
- Reduction target ≥ 50 kW
- Usage within the typical PGE peak window: weekdays between 3 and 7 p.m.

Energy Partner Fact Sheet

Energy Partner fact sheet

How it works

- EnerNoc evaluates historical usage and performs a site visit to identify potential areas of reduction.
- The customer and EnerNoc develop an energy reduction plan to determine the amount of electricity that can be reduced during an event.
- EnerNoc installs monitoring equipment and performs a test to validate the reduction.
- The customer is enrolled in the program and nominated for a specific load-reduction amount.

How much it pays

There are two types of payments:

- Capacity Payments – regardless of whether or not an event is called the customer gets paid a capacity payment for each month they are enrolled in the program.
- Energy Payments – the customer is paid for the total kW reduced during the event (the payment is dependent upon the nomination amount)

Sample 1st Year Payment Estimates			
	50 kW	200 kW	1000 kW
Capacity Payment	$1,700	$6,800	$34,000
Estimated Energy Payment*	$125	$500	$2,500
Total	$1,825	$7,300	$36,500

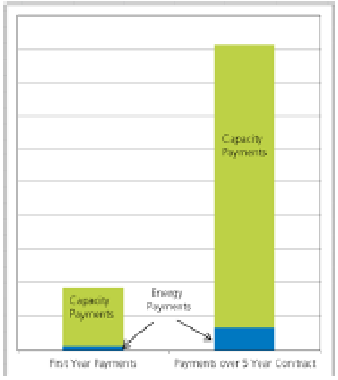
Sample Contract Payment Estimates (5 years)			
	50 kW	200 kW	1000 kW
Capacity Payment	$8,500	$34,000	$170,000
Estimated Energy Payment*	$625	$2,500	$12,500
Total	$9,125	$36,500	$182,500

**Based on a sample estimate of 20 event hours per year*

Additional Benefits

- Free real-time energy meters
- Potentially reduce the ROI on complementary energy savings activities
- Online access to real-time energy usage through the Demand Response portal
- Avoided energy costs
- Reduced carbon footprint
- Help support reliable and responsible energy for the community

Estimated Payments



Energy Partner Fact Sheet

Portland General Electric

Energy Partner Fact Sheet

Energy Partner℠ pays you to manage energy.

As one of the Smart Power℠ options available from Portland General Electric, the Energy Partner program rewards you for changing your energy use when demand is high. As a participant, you'll receive financial compensation, tools for managing your energy use and a boost to your corporate image through the reduction of your carbon footprint.

Here's how it works and how you can benefit.

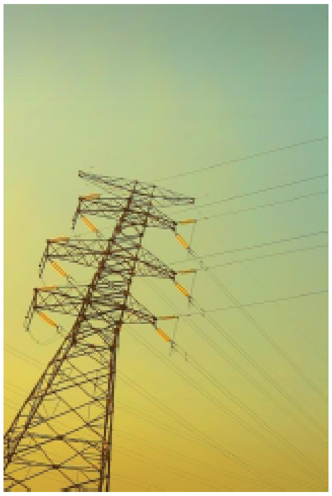
The Energy Partner program pays you to reduce or shift energy use during certain peak times, usually hot summer or cold winter days, to help support PGE's power generation resources. Common energy shifting and reduction strategies include:

- Temporarily shifting non-critical production processes by a few hours
- Shifting HVAC set points for a short period of time
- Adjusting VFDs on pumps or motors for a short period of time

Participating in Energy Partner events can be completely automated, requiring very little effort on your part after initial installation of an alert system. PGE has hired demand response industry leader EnerNOC, Inc. to work with you to determine what electrical loads can acceptably be reduced or shifted. The amount you will be paid will vary based on how much energy you can reduce or shift and the frequency of Energy Partner events.

Customized solutions for your business.

EnerNOC has extensive experience creating energy shifting and reduction strategies in a wide variety of industries, including grocery stores, food processing and storage, manufacturers, office buildings and more. PGE's energy experts and EnerNOC will work with you to identify which techniques will help you maximize your reward while being the right fit for your business.



How you benefit

Use the latest smart energy technology to your advantage.

- Get paid for participating
- Access real-time energy information to better manage your energy use
- Save by reducing or shifting your use, with minimal effort on your part
- Boost your sustainability

Energy Partner Fact Sheet

Energy Partner Fact Sheet

What type of compensation will I receive?

Your payment will be based on your level of participation. We will work with you to evaluate compensation based on your specific Energy Partner strategies.

When can Energy Partner events be called?

Program events can occur Monday through Friday, excluding designated holidays, during the summer and winter seasons. Event hours are limited to:

- Summer (July, August and September): Noon - 10 p.m.
- Winter (December, January and February): 6 - 11 a.m. and 4 - 9 p.m.

Events may last up to five hours a day and may not be called on more than two consecutive days. In total, events are limited to a maximum of 40 total hours during any summer or winter season.

What happens during an event?

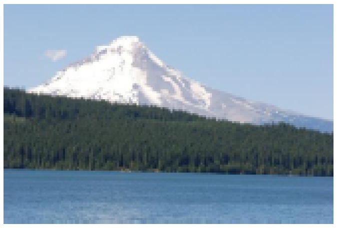
When PGE anticipates need for an event, the alert system is dispatched. EnerNOC will notify you of the event and energy reductions begin as agreed upon. You can override the event if you wish with no penalty, but participation is required to earn payments.

What are other benefits of the Energy Partner program?

While EnerNOC's online application is primarily used to manage demand response event dispatch, you can take advantage of a number of other features of the system, including 24/7 access to real-time, high-resolution power monitoring that is useful for load profiling, facility benchmarking, and proactive facility maintenance.

How do I sign up for the Energy Partner program?

If you are interested in the program, please contact your PGE representative or PGE Business Services at 800-822-1077. You can also contact EnerNOC's customer service by calling 888-363-7662.



Responsible energy for Oregon

Your participation helps our community become stronger, more flexible and green.

- Put power back into the grid and decrease the need for new power generation.
- Help ensure reliable and responsible energy for Oregon.
- Promote your participation as a corporate responsibility initiative.
- Reduce your carbon footprint.

Energy Partner Customer Spotlight

Portland General Electric

Energy Partner[SM] Customer Spotlight

The Joint Water Commission (JWC) is the primary drinking water supplier in Washington County, Oregon, and is responsible for treating, transmitting and storing potable water for approximately 365,000 customers. Handling up to 75 million gallons of water a day, JWC knows how energy and water are intertwined and realizes the importance of saving both resources.

The big picture

JWC wasn't sure they could participate in Energy Partner, but PGE worked with them to determine the electrical loads they could reduce or shift. Knowing JWC had full control over their participation, with plenty of advance notice for events and the option to not participate in any event was reassuring.

Together, JWC, PGE and EnerNOC created a customized energy plan for JWC that includes a full shutdown of the plant for a few hours at a time during the winter, and reducing the use of selected pumps in the summer based on production needs. JWC thought this was the ideal solution for its facility.

"Setup was flawless and it happened quickly. EnerNOC handled installation with PGE and those of us at the plant had nothing to do but let them in the gate."

— Chris Wilson, Assistant Water Manager at JWC

As a participant in the Energy Partner program, JWC also gained valuable insight into its energy use with free, 24/7 access to real-time, high-resolution power monitoring tools they find useful for load profiling, facility benchmarking and proactive facility maintenance.

"We learned a standby backup power generator we are completing can keep us running at 100 percent most of the year," said Wilson. "We wouldn't have known that without the complementary energy monitoring that came with being an Energy Partner."

The results

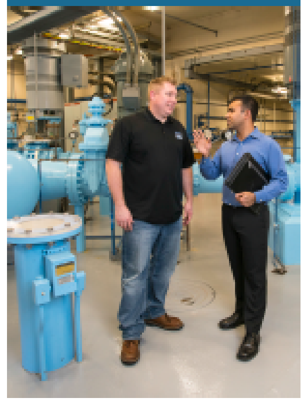
In its first winter of participation, JWC reduced energy costs and generated extra revenue to improve its bottom line. By participating in the Energy Partner program, Joint Water Commission is putting power back on the grid during peak times when it is most needed, demonstrating sensible stewardship of public resources, and helping to ensure reliable, responsible energy for Oregon.

PGE

Find more information online:

PortlandGeneral.com/EnergyPartner

Questions? Contact your PGE representative or PGE Business Services at 503-612-3556 or GeneralBusiness@pgn.com



Fast Facts

Joint Water Commission

JWC

- ***Industry:*** *Water treatment*
- ***Location:*** *Forest Grove*
- ***Energy Partner Strategy***
  Winter:
  — Full plant shut down

  Summer:
  — Reduction of select pumps based on production needs
- ***Curtailable Load:*** *1,800 kW*

Flex Pricing Pilot

Flex Recruitment E-mail:

Enroll in Flex and get a $10 Gift Card!

With our new Flex plan, you could earn up to $48 this year* simply by making small changes in the way you use energy.

We'll reward you to "flex" your energy use away from high-demand times such as hot summer days, to times when energy is less expensive for us to produce.

To learn more, click the button below to visit the Flex website and sign in as a first-time user. Don't worry, setting up and account does not automatically enroll you in Flex. You'll just get a detailed program overview to help you decide if you'd like to enroll.

Choose this special pricing plan by July 31, and we'll also send you a $10 Amazon.com Gift Card** as a special thank you.

Flex Recruitment E-mail:

Say hello to Flex, a new pricing plan from PGE

With our new Flex pricing plan, you could save up to 60% on electricity costs during off-peak times*, simply by making small changes in the way you use energy. We'll reward you to "flex" your energy use away from high-demand times, to times when energy is less expensive to produce.

Here's how It works:

- We make it easy by giving you a Flex schedule that shows you when peak times occur throughout the week
- We'll show you how to save with simple tips, like waiting to do your laundry until lower-demand times
- The less you use during peak times, the more you save

To learn more, click the button below and sign in on the Flex website as a first-time user. Setting up an account will not automatically enroll you in Flex. It lets you

Flex Recruitment E-mail:

Based on your energy use, you could earn up to $224* this year.

Say hello to Flex, a new pricing plan from PGE.

Flex is an exciting, easy opportunity to earn money simply by reducing your energy use during times when there's high demand for electricity. We call these "Flex times." Use less during these times, and we'll send you a check at the end of the season based on how much you reduce. It's that simple.

When you enroll in Flex:

- PGE will notify you of a Flex time by text, email or phone call (your choice).
- You'll get tips on simple ways to use less energy during Flex times.
- Each winter and summer, you will have six to 10 opportunities to Flex, each lasting between two and five hours.

Flex is completely voluntary, but the more you shift your energy use from Flex times, the **more you get paid!**

Hurry, space is limited.

Flex Recruitment E-mail:

Based on your energy use, you could save up to $51* this year.

Say hello to Flex, a new pricing plan from PGE.

During certain times of the day — like first thing in the morning or after work — we all use more electricity.

That's why we're offering Flex — an easy new program where you can save money simply by shifting your electricity use to lower-demand times such as nights and weekends.

Here's how It works:

- We give you a personal Flex schedule that shows you when energy costs are lower throughout the week.
- We'll show you how to save with simple tips, such as waiting to do your laundry until lower-demand times.
- The more you Flex, the more you save — as much as **$51*** per year — on your PGE bill!

It's that easy.

Flex Recruitment E-mail:

Sign up for Flex and get two tickets to the Oregon Zoo!

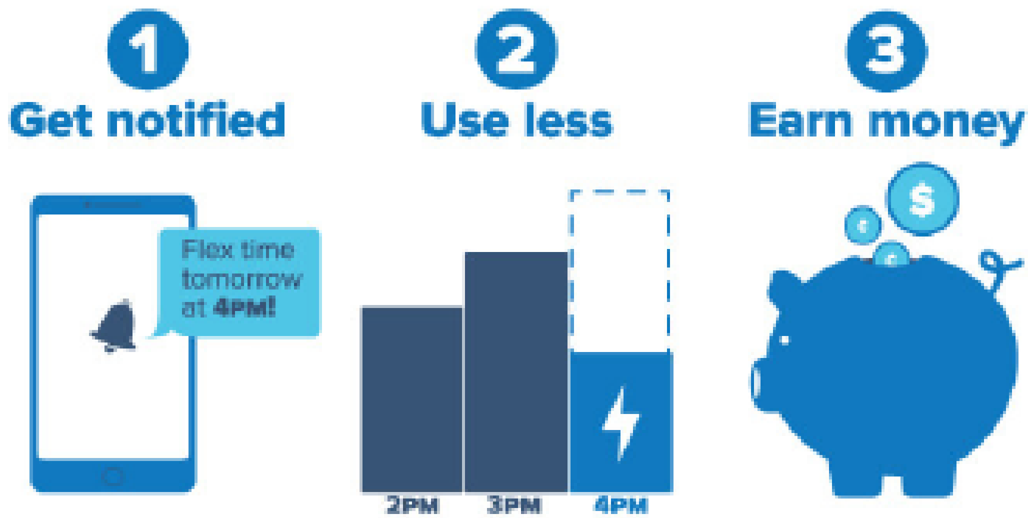
With our new Flex plan, you could earn up to $104 this year* simply by making small changes in the way you use energy.

We'll reward you to "flex" your energy use away from high-demand times such as hot summer days, to times when energy is less expensive for us to produce.

Choose this special pricing plan by June 30, and we'll also send you two tickets to the Oregon Zoo as a special thank you.

Flex Enrollment E-mail:

Congratulations!



You're officially enrolled in Flex. We hope you're excited to participate in this innovative new program where we pay you to make small changes to your energy use.

Be on the lookout for your first Flex time notification alerting you of the next Flex event date and time. We'll let you know by email, text or phone call—whichever you chose when you applied.

In the meantime, visit your Flex profile to update your notification preferences and get energy-saving tips. You can also access special discounts and mobile coupons via the Chinook Book app just for participating in Flex.

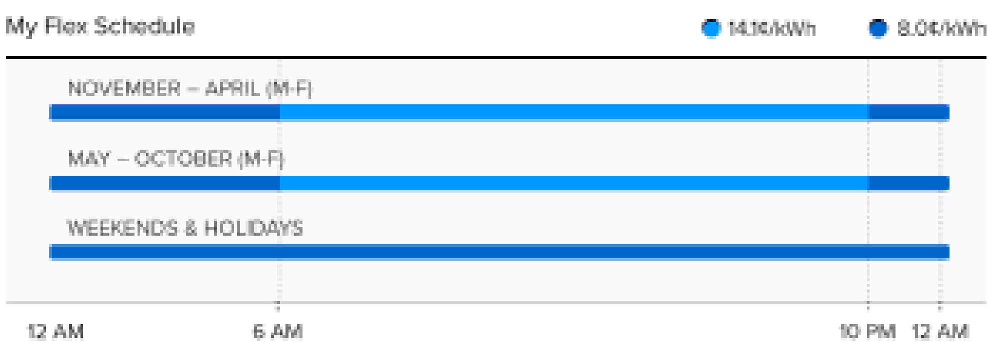
If you have any questions, please contact a Flex Specialist at 866-503-9022 or flex@pgn.com.

START FLEXING

Flex Recruitment E-mail:

Congratulations!

You are officially enrolled in the Flex program. Now you'll start earning rewards for making small changes to your energy use based on your Flex schedule below.*



We'll send you a monthly email letting you know how much you're spending on the Flex plan compared to PGE's basic service.

View your Flex profile to see your personal schedule and get tips on how to shift your energy usage to lower demand, discounted times. You can also view your monthly results and access special discounts and mobile coupons via the Chinook Book app just for participating in Flex.

If you have any questions, please contact a Flex Specialist at 866-503-9022 or flex@pgn.com.

START FLEXING

Flex Start of Season E-mail:

Winter cheer is almost here!

Flex your energy use this winter
and earn rewards

Your first winter season starts Dec. 1. Remember, with Flex, you're helping your community keep energy costs low and protect the environment. You'll earn rewards for "flexing" your energy use away from high-demand times, such as a few hours on cold winter days, to times when energy is less expensive and cleaner to produce.

Here's how it works:

1. We'll notify you the day before a Flex time by your choice of text, email or phone call.
2. The less energy you use during a Flex time, the more you'll help our community.
3. We'll send you an email shortly after the Flex day letting you know how much energy you've saved.

Flex Finish Enrollment Email:

You're almost there!

Our records show that you started the enrollment process for PGE's Flex pricing plan, but didn't finalize your enrollment. Would you like to complete your enrollment now and earn **up to $** this year?* Simply click the button below.

CONFIRM ENROLLMENT

Why is saving energy during high-demand times important?
We all use more energy at certain times of the day and on certain days of the year. If everyone uses even a little less energy during these times, it decreases our need to buy more expensive power to meet that demand, which helps keep prices lower for everyone. The more you flex your energy use, the more you can earn.

Login with your username and password to learn how you can earn money with your Flex plan.
*Based on your actual usage

Flex Follow-up E-mail:

PGE

Thank you for your interest in Flex!

We're not accepting enrollments right now, but we'll make sure to let you know when there's a chance to be part of Flex in the future.

In the meantime, you may be interested in these other ways to save energy:

- Time of Use – with lower prices on nights and weekends and increased prices at high-demand times such as weekday mornings and evenings.
- Energy Tracker – an easy way to monitor your energy use.
- Energy Saving Tips – dozens of low-cost and no-cost ways to save.

To thank you for your interest and your time, we will be sending you a $5 Amazon.com Gift Card*. You can expect to receive the electronic Gift Card via email in the next 4-8 weeks.

If you have any questions, please contact us at 866-503-9022 or flex@pgn.com.

Roch Naleway,
Flex Program Manager

*Amazon.com is not a sponsor of this promotion. Except as required by law, Amazon.com Gift Cards ("GCs") cannot be transferred for value or redeemed for cash. GCs may be used only for purchases of eligible goods at Amazon.com or certain of its affiliated websites. For complete terms and conditions, see www.amazon.com/gc-legal. GCs are issued by ACI Gift Cards, Inc., a Washington corporation. All Amazon ®, ™ & © are IP of Amazon.com, Inc. or its affiliates. No expiration date or service fees.

Terms and conditions:

This is a limited time offer exclusive to invited Portland General Electric customers. This offer is not valid with any other Flex promotional offer.

Flex Event Tomorrow Email:

Tomorrow is Flex time!

There will be a Flex time tomorrow, February 01, 2017, from 7:00AM to 10:00AM.

Here's a tip to help you save:

Heating is the No. 1 energy user in your home. If you have electric heat, turning down your thermostat a few degrees or programming your thermostat to a lower temperature during a Flex time will help boost your savings.

With Flex, timing is everything.
We all use more energy at certain times of the day and on certain days of the year. If everyone uses even a little less energy during these times, it decreases our need to buy more expensive power to meet that demand, which helps keep prices lower for everyone. The more you flex your energy use, the bigger difference you can make.

Here's how it works:

- When possible, shift your energy use to either before the Flex time above or after it ends.
- After each Flex time, we'll send you personalized results, which are also viewable on your personal online Flex profile.
- Each winter and summer, you will have six to 10 opportunities to Flex, each lasting between two and five hours.

Want more ways to reduce your energy use?
Look for tips on Flex emails or log in to your Flex profile for a range of options.

For more information, view your online Flex profile or contact a Flex Specialist at 866-503-9022 or flex@pgn.com. Flex Specialists can also give you your first-time user online activation code if you missed your introductory Flex email in July.

Flex Event Tomorrow Email:

Tomorrow is Flex time!

There will be a Flex time tomorrow, February 03, 2017, from 7:00AM to 10:00AM. Remember, the less energy you use during Flex time, the more you'll earn. Use this tip to help you save:

Since water heating is your home's second largest energy user after space heating, try washing clothes or dishes and taking showers before or after the Flex time.

View your Flex profile for more simple ways to save.

VIEW FLEX PROFILE

Flex Event Today Email:

Today is Flex time!

There will be a Flex time today from 7:00AM to 10:00AM. Remember, the less energy you use during Flex time, the more you'll help the community. Use this tip to help you save:

Microwaves use less than half the energy of a conventional oven. Consider using your microwave to cook or reheat your meals during Flex times.

View your Flex profile for more simple ways to save.

VIEW FLEX PROFILE

Flex How You Did Email:

PGE

Here's how you did during the February 01, 2017 Flex time

Your flex use – **2.43 kWh**

Your expected use – **2.52 kWh**

Great job!

You used 3% less than your expected use. Keep it up!

Here's a tip to help you save more next time:

Visit a museum, ice skating or other attractions during Flex times with your discounts in the My Rewards section.

View your Flex profile for more information about the program, a detailed look at your Flex time results, and additional tips for how to be successful during Flex time.

VIEW FLEX PROFILE

Questions? Contact a Flex Specialist at 866-503-9022 or flex@pgn.com.

Flex How You Did Email:

PGE

Here's how you did during the February 01, 2017 Flex time

Your flex use – **6.53 kWh**

Your expected use – **4.5 kWh**

You used 45% more than we expected you to use. Try out some of our simple tips to shift more next time.

Here's a tip to help you save more next time:

Visit a museum, ice skating or other attractions during Flex times with your discounts in the My Rewards section.

View your Flex profile for more information about the program, a detailed look at your Flex time results, and additional tips for how to be successful during Flex time.

VIEW FLEX PROFILE

Questions? Contact a Flex Specialist at 866-503-9022 or flex@pgn.com.

Flex Thank You E-mail:

Thanks for flexing!

Your rewards are here.

Thank you for participating in the Flex program, which rewards you for making small changes to your energy use during high-demand times, called Flex times. You're doing great!

Check out your rewards

Have you seen the coupons and discounts available on your Flex dashboard? We've teamed up with Chinook Book to bring you more than 100 offers on activities — from movies to restaurants — that can make using less electricity during Flex times easy and fun. You'll find your Rewards section at the bottom of your Flex dashboard.

The results are in

We're compiling your Flex time results and will upload those to your dashboard in October.

Flex Winter Report:

Welcome to your Flex winter season report

Thank you for participating in the Flex program, which rewards you for making small changes to your energy use for a few hours during high-demand times, called Flex times.

Here's how you did:

You reduced

5%

For the season ending Feb. 28, there were seven opportunities to Flex and you reduced your energy use by **5%** during Flex times. To see how much energy you reduced during each Flex time, visit your Flex dashboard.

Making a difference

Together, everyone flexed **68,092 kWh** of energy use this winter. That's enough energy saved to do **151,315** loads of laundry.

151,315

Need a refresher about how Flex works or how to reduce your energy during Flex Times? For more tips, and to keep tabs on your energy use, check out your Flex dashboard. We'll be in touch to let you know how you're doing.

Flex Winter Report:

PGE

Welcome to your Flex winter season report

Thank you for participating in the Flex program, which rewards you for making small changes to your energy use during high-demand times, called Flex times. You're doing great!

Here's how you did:

You reduced

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Flex Winter Report:

PGE

Welcome to your Flex winter season report

Thank you for participating in Flex, which pays you to make small changes to your energy use for a few hours during high-demand times, called Flex times.

Here's how you did:

You earned

$10

There were eight opportunities to Flex this winter and based on your participation you earned **$10**. You will receive your Flex payment for the season ending Feb. 28 in the mail next week. To see how much energy you reduced during each Flex time, visit your Flex dashboard.

Making a difference

Together, everyone flexed **68,092 kWh** of energy use this winter. That's enough energy saved to do **151,315** loads of laundry.

151,315

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Here's how you did:

You earned

$10

There were eight opportunities to Flex this winter and based on your participation you earned **$10**. You will receive your Flex payment for the season ending Feb. 28 in the mail next week. To see how much energy you reduced during each Flex time, visit your Flex dashboard.

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Check out your rewards

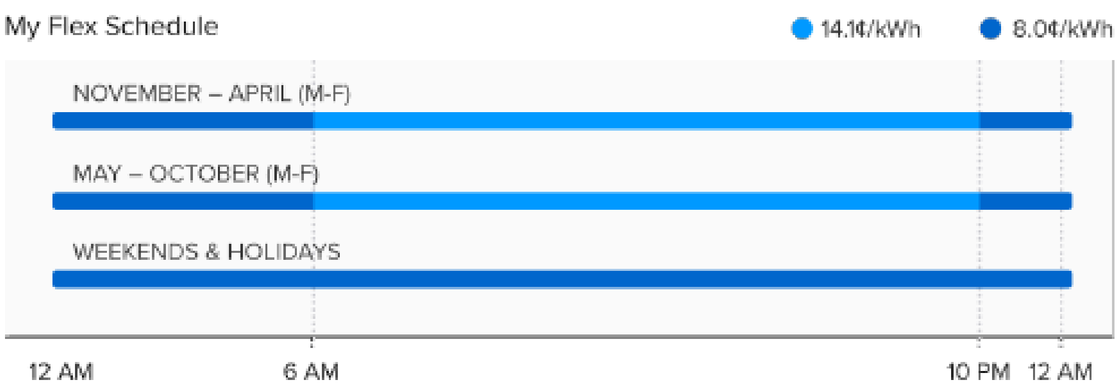
Have you seen the coupons and discounts available on your Flex dashboard? We've teamed up with Chinook Book to bring you more than 100 offers on activities — from movies to restaurants — to thank you for participating in Flex.

Flex Guarantee Notification:

Uh-oh!

Based on the way you used energy, your electricity bill was $5.00 more last month than it would have been on PGE's basic service. But don't worry — you're protected with your Flex guarantee*, and there's still time to save! Next month, try shifting your energy use to less expensive times, shown below in dark blue on your Flex schedule.

Please note — since it's common to use more electricity in the winter, you may not save as much during the next few months but by sticking to your Flex schedule below, you should save more in the spring and fall to reduce your annual energy bill.



Use this quick tip for more savings

Check out the restaurant coupons in the My Rewards section – take a break from cooking during more expensive hours.

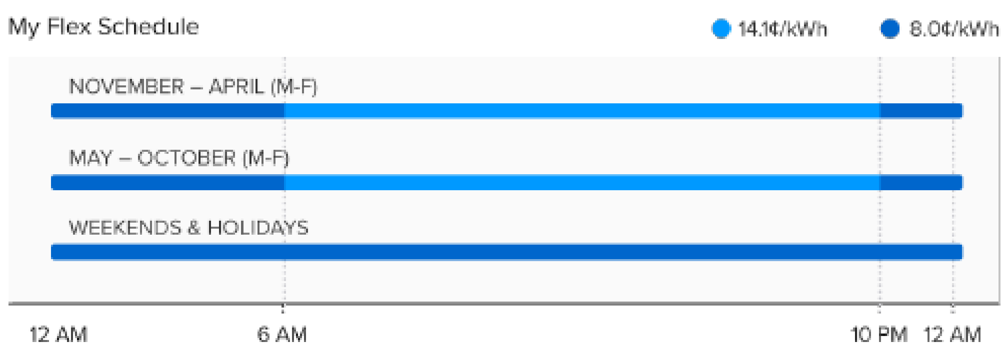
For more tips, and to keep tabs on your energy use, check out your Flex dashboard. We'll be in touch next month to let you know how you're doing.

Flex Last Month Report:

Nice Job!

You saved $5.00 with Flex last month

Congratulations! You really took control of your energy bill last month! Keep shifting your energy use to less expensive times, shown below in dark blue on your Flex schedule, to save even more.



Use this quick tip for more savings

Check out the restaurant coupons in the My Rewards section – take a break from cooking during more expensive hours.

For more tips, and to keep tabs on your energy use, check out your Flex dashboard. We'll be in touch next again month to let you know how you're doing.

Flex Welcome Insert:

Say hello to Flex

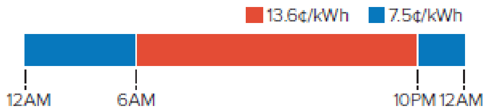
A new way to take control of your energy costs and save money this year. **With Flex, timing is everything.**

Here's how it works:

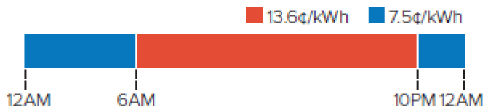
- Check out your Flex schedule on the back of this card that shows you when energy costs are lower throughout the week.
- We'll provide tips on simple ways to use less energy during high-demand times.
- The less you use during high-demand times, the more you'll save on your PGE bill.
- If you end up spending 10% more on the Flex plan than on your regular pricing plan after your first year, PGE will send you a check for the difference.
- Flex is completely voluntary — you can opt out at any time.

Your Flex schedule

May — October (M-F)



November — April (M-F)



Weekends & Holidays

The cost of electricity on PGE's basic service is 10.6¢/kWh, no matter what time of day, day of week, or time of year it is. If you use more than 1,000 kWh per month, the cost is 11.3¢/kWh.

The charges for PGE's basic service and the Flex schedule don't include other charges — like our basic service charge, taxes and other adjustments — and don't reflect your total bill.

PortlandGeneral.com/Flex

PGE

Flex Welcome Insert:

Say hello to Flex

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Here's how it works:

- Check out your Flex schedule on the back of this card that shows you when energy costs are lower throughout the week.
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- The less you use during high-demand times, the more you'll save on your PGE bill.
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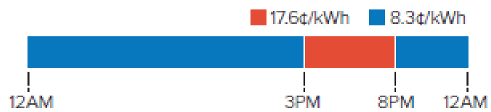

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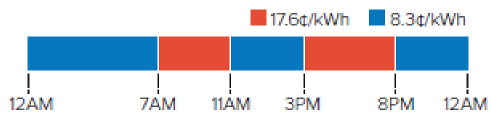

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The charges for PGE's basic service and the Flex schedule don't include other charges — like our basic service charge, taxes and other adjustments — and don't reflect your total bill.

PGE

PortlandGeneral.com/Flex

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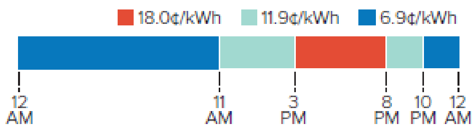
Here's how it works:

- Check out your Flex schedule on the back of this card that shows you when energy costs are lower throughout the week.
- We'll provide tips on simple ways to use less energy during high-demand times.
- The less you use during high-demand times, the more you'll save on your PGE bill.
- If you end up spending 10% more on the Flex plan than on your regular pricing plan after your first year, PGE will send you a check for the difference.
- Flex is completely voluntary — you can opt out at any time.

Your Flex schedule

May — October (M-F)



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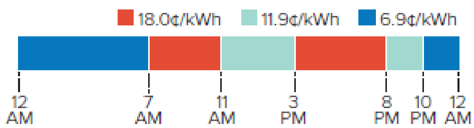

Weekends & Holidays

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The charges for PGE's basic service and the Flex schedule don't include other charges — like our basic service charge, taxes and other adjustments — and don't reflect your total bill.

PGE

PortlandGeneral.com/Flex

Flex Welcome Insert:

Say hello to Flex

With Flex, PGE pays you to make small changes that reduce or shift your energy use away from high-demand times, so you earn cash while staying comfortable.

1. Get notified
2. Use less
3. Earn money

A new way to take control of your energy bill and earn money this year. **With Flex, timing is everything.**

Here's how it works:

- PGE will notify you of a Flex time by text, email or phone call (your choice).
- You'll get tips on simple ways to use less energy during Flex times.
- When possible, shift your energy use to either before the Flex time begins or after it ends.
- After each Flex time, we'll send you personalized results, which are also viewable on your personal online profile.
- Each winter and summer, you will have six to 10 opportunities to Flex, each lasting between two and five hours.
- Flex is completely voluntary — you can opt out at any time!
- **At the end of the season, you get a check based on how much you shifted.**

PortlandGeneral.com/Flex

Flex Targeted Mailer:

Portland General Electric
121 SW Salmon Street • Portland, Ore. 97204

Month 00, 2016

FIRSTNAME LASTNAME
FIRSTNAME LASTNAME
1234 ANYWHERE ST APT 1
PORTLAND OR 97000-1234

Based on your energy use, you could save $X,XXX this year!*

PGE's new pricing plan may be better for you.

During certain times of the day — like first thing in the morning and right after work — we all use more electricity.

To help keep power affordable, we're offering Flex — an easy new program where you can save money simply by shifting your energy use to lower-demand times such as nights and weekends.

Based on your account history, you could save $X,XXX per year on the Flex plan!*

When you enroll in Flex:

- You get a personalized Flex schedule that shows you when energy costs are higher and lower throughout the week — check out your schedule in the attached insert.
- You get tips on simple ways to shift your energy use, like waiting to do your laundry until energy costs are lower.
- The more you Flex, the more you save on your PGE bill!

Additional perks:

- Go online to discover your personalized energy graph, which shows your hourly and daily electricity use.
- Take advantage of discounts on activities — from movies to restaurants — and mobile coupons via the Chinook Book app that can make using less electricity during Flex times easy and fun.

Choose one of these easy ways to enroll

1. Online — Visit PortlandGeneral.com/Flex and sign up using **code AK41**.
2. Fill out the simple form below, and drop it in the mail — we've paid the postage.

You could be among the first to take advantage of new pricing and energy management tools. Enrollment is limited, so sign up for Flex today!

*Based on your account history if you shift 15% of your energy use to lower-demand times.

Yes! I'm ready to take control of my energy use.

Please enroll me in Flex!

Firstname Lastname

To enroll you in the program, we need your email address.

Email address (Required): ______________________________

Flex Mailer FAQs:

Frequently asked questions

Why is saving energy at high-demand times important?
We all use more energy at certain times of the day and on certain days of the year. If everyone uses even a little less energy during these times, it decreases our need to buy more expensive power to meet that demand, which helps keep prices lower for everyone. The more you flex your energy use, the more you can save.

Does it cost anything to participate in Flex?
No. Signing up for Flex is free.

Where can I find more specific information about Flex?
Visit My Flex Plan at PortlandGeneral.com/Flex for personalized information about the program, its timing, and what it means to you. The first time you log in, you'll need the activation code on the front of this letter.

Will I lower my energy bill by signing up for Flex?
Reducing or shifting your energy use could result in a lower bill. Check out your personalized My Flex Plan at PortlandGeneral.com/Flex and check out our tips for shifting your energy use to maximize your results.

Why do you need my email address?
To participate in the Flex program, we need to be able to send you information about the program — how you are doing and how much you are saving on Flex.

Can I provide feedback to PGE on the Flex program?
We value and welcome your input. If you have any questions or comments, please contact us at 866-503-9022 or flex@pgn.com.

Flex Targeted Mailer:

Based on your energy use, you could earn $X,XXX this year.*

Say hello to Flex, a new pricing plan from PGE.

Flex is an exciting, easy opportunity to earn money simply by reducing your energy use during times when there's high demand for electricity. Use less during these times, and we'll send you a check at the end of the season based on how much you reduce. It's that simple.

When you enroll in Flex:

- PGE will notify you of a Flex time by text, email or phone call (your choice).
- You'll get tips on simple ways to use less energy during Flex times.

The more you shift your energy use from Flex times, the more you get paid!

Additional perks:

- Go online to discover your personalized energy graph, which shows your hourly and daily electricity use.
- Take advantage of discounts on activities — from movies to restaurants — and mobile coupons via the Chinook Book app that can make using less electricity during Flex times easy and fun.

Choose one of these easy ways to enroll

1. Online: Visit PortlandGeneral.com/Flex, and sign up using **code AK41.**
2. Mail: Fill out the simple form below, and drop it in the mail — we've paid the postage.

You could be among the first to take advantage of new pricing and energy management tools. Enrollment is limited, so sign up for Flex today!

*Based on your account history if you shift or reduce 30% of your normal energy use during Flex times.

Flex Enrollment by Mail:

Yes! I'm ready to get paid for managing my energy use.

Please enroll me in Flex!

Firstname Lastname
Firstname Lastname
10090 SW Beaverton Hillsdale HWY
Apt 16
Beaverton, OR 97005-3254
CODE AK41

To enroll you in the program, we need your email address.

Email address (Required): ____________________
Please Print

Signature: ____________________
Must match one of the names on the PGE account listed on the left

How would you like to receive Flex Time notifications?
Check all that apply

☐ Phone (print number): ____________________

☐ Text message (print number): ____________________
Text fees may apply. Check with your mobile carrier

☑ Email address noted above

Flex Mailer FAQs:

Frequently asked questions

Why is saving energy at high-demand times important?
We all use more energy at certain times of the day and on certain days of the year. If everyone uses even a little less energy during these times, it decreases our need to buy more expensive power to meet that demand, which helps keep prices lower for everyone. The more you flex your energy use, the more you can save.

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What kind of actions can I take during Flex Times?
Simple things, such as turning down your heater a bit, using less hot water or postponing running your dishwasher. Check out your personalized My Flex Plan at PortlandGeneral.com/Flex and view our tips for shifting your energy use to maximize your results.

Will I lower my energy bill by signing up for Flex?
Reducing or shifting your energy use could result in a lower bill. Check out your personalized My Flex Plan at PortlandGeneral.com/Flex and check out our tips for shifting your energy use to maximize your results.

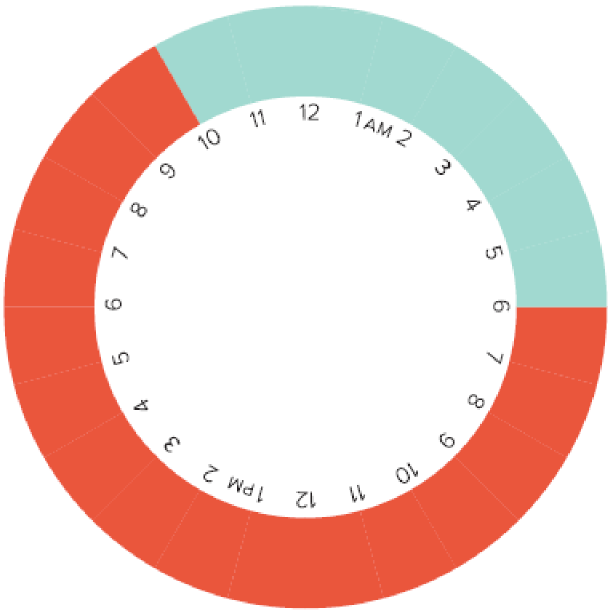
Why do you need my email address?
To participate in Flex, we need to be able to send you notices about Flex times as well as how you are doing and how much you are saving on the program. If more than one person in your household would like to receive notifications, you can add contact information to your profile – just give us a call at 866-503-9022.

Can I provide feedback to PGE on the Flex program?
We value and welcome your input. If you have any questions or comments, please contact us at 866-503-9022 or flex@pgn.com.

Flex Sticker:

Save with Flex

PGE



8.0¢/kWh

M–F 10PM–6AM

All day weekends
and some holidays

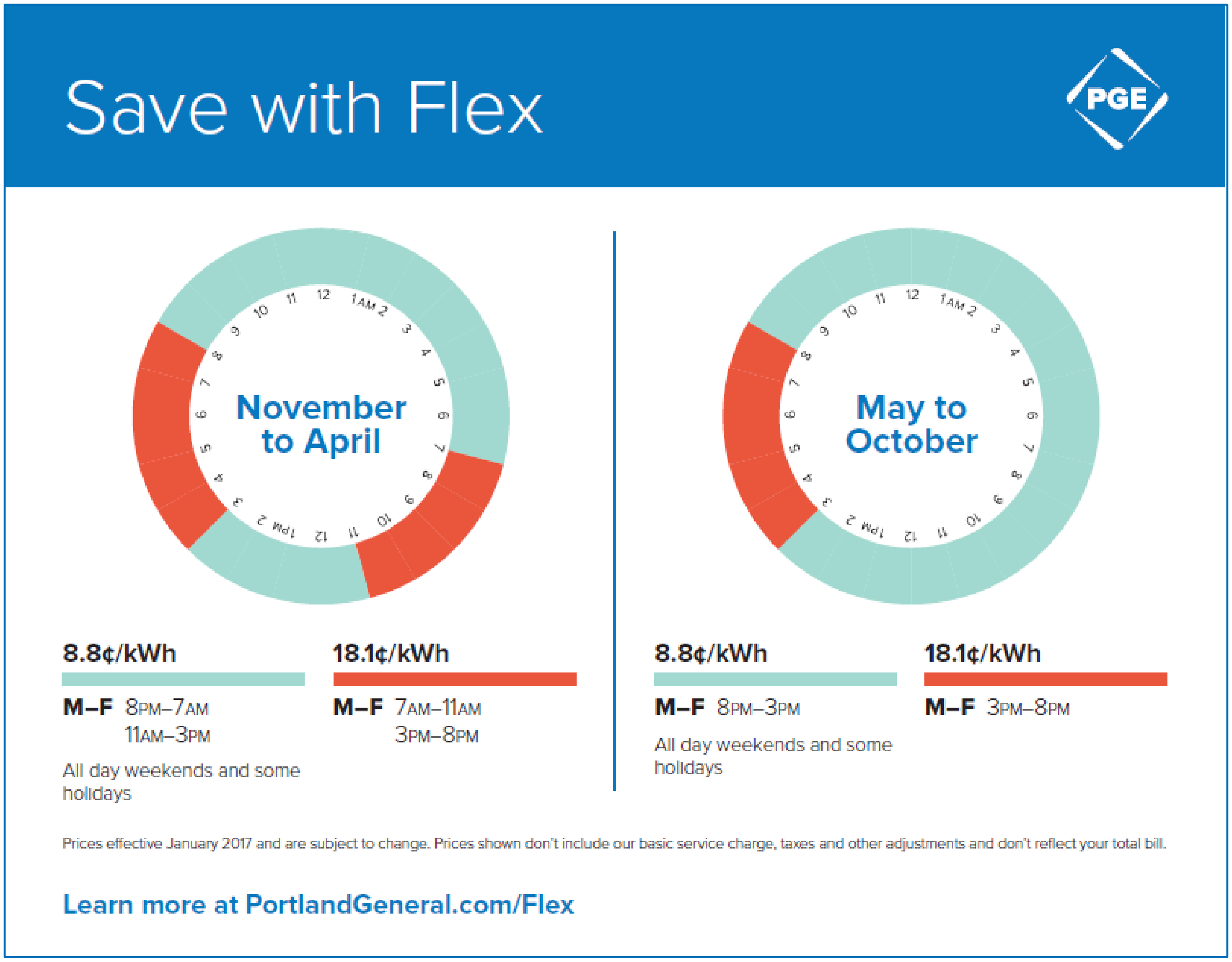
14.1¢/kWh

M–F 6AM–10PM

Prices effective January 2017 and are subject to change. Prices shown don't include our basic service charge, taxes and other adjustments and don't reflect your total bill.

You'll also get paid for special Flex times throughout the year! Learn more at PortlandGeneral.com/Flex

Flex Sticker:



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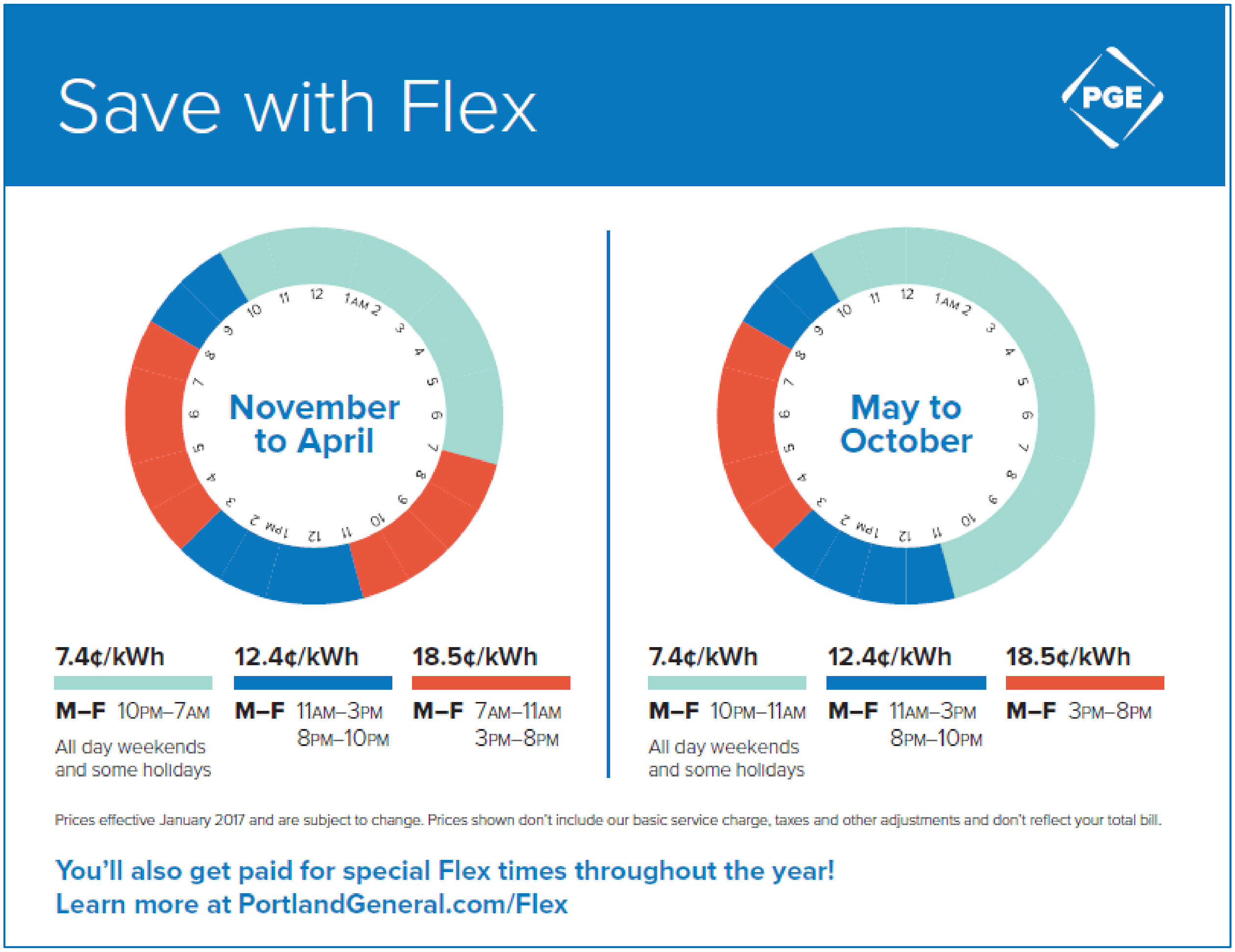
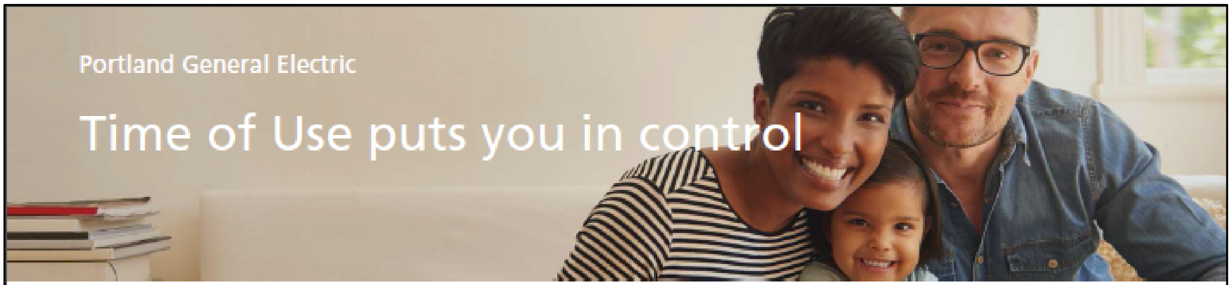


Standard Time of Use Flyer



How Time of Use works.
Portland General Electric's Time of Use pricing plan offers certain residential and small business customers a great way to control their energy costs. On the Time of Use plan, you pay different rates for electricity depending on when you use it.

The Time of Use plan divides days and hours among three different price categories—On-Peak, Mid-Peak and Off-Peak—and these periods shift slightly between summer and winter.

Is Time of Use right for you?
It helps to first understand how you use electricity. There is the "always on" electrical load in your home, such as your refrigerator. Then there is the load you manage—running the dishwasher, bathing, and other activities—which can be moved to different times.

Go to PortlandGeneral.com/TimeOfUse to determine if Time of Use is a good choice for you or if you would like to sign-up.

Residential time of use periods and energy charges

	Summer Months (begins May 1 of each year)	Winter Months (begins Nov. 1 of each year)	EXAMPLE: 80kWh for one month of drying clothes, family of three	How this compares to PGE's Basic Service
On-Peak 12.323¢/kWh*	3 p.m. – 8 p.m. Monday – Friday	6 a.m. – 10 a.m. & 5 p.m. – 8 p.m. Monday – Friday	$9.86*	More expensive
Mid-Peak 7.072¢/kWh*	6 a.m. – 3 p.m. & 8 p.m. – 10 p.m. Monday – Friday; 6 a.m. – 10 p.m., Saturday	10 a.m. – 5 p.m. & 8 p.m. – 10 p.m. Monday – Friday; 6 a.m. – 10 p.m., Saturday	$5.66*	Same rate as Basic Service
Off-Peak 4.109¢/kWh*	10 p.m. – 6 a.m. weekdays & Saturday; all day Sunday & specified holidays**	10 p.m. – 6 a.m. weekdays & Saturday; all day Sunday & specified holidays**	$3.29*	Less expensive

* These charges do not reflect your total bill; it is only the energy portion of your bill. There are other charges that every PGE customer receives, whether on Time of Use or Basic Service. These additional charges are the same for everyone, and include items such as basic charge, distribution and transmission charges or supplemental adjustments. Please visit the calculator on our website to see how Time of Use may affect the energy portion of your bill. Prices subject to change. You also receive a credit of 0.722 cent/kWh for the first 1,000 kWh used. Visit our website for current prices.

** New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

Appendix 5. Related Dockets and Commission Orders

Table 36: Related Dockets and Commission Orders

Docket No.	Subject
ADV 147	Residential Pricing Pilot (Schedule 6)
ADV 507	Water Heater Pilot (Schedule 3)
AR 603	Community Solar
LC 66	2016 Integrated Resource Plan
UM 1514	Deferral of Incremental Costs Associated Automated DR
UM 1708	Deferral of Expenses Associated with Two Residential DR Pilots
UM 1716	Investigation to Determine Resource Value of Solar
UM 1751	Implementing an Energy Storage Program Guidelines (HB 2193)
UM 1758	Solar Report to Oregon Legislature
UM 1811	Transportation Electrification Program Applications
UM 1827	Deferred Costs of Demand Response Water Heater Pilot

Appendix 6. Cost Effectiveness Workshop

Background

- Questions on cost-effectiveness/avoided cost methodologies of distributed energy resources (DER) and demand-side management (DSM) across dockets:

Docket No.	Subject
ADV 147	Residential Pricing Pilot (Schedule 6)
ADV 507	Water Heater Pilot (Schedule 3)
AR 603	Community Solar
UM 551	Cost Effectiveness of Energy Efficiency
UM 1716	Investigation to Determine Resource Value of Solar
UM 1751	Implementing an Energy Storage Program Guidelines (HB 2193)
UM 1758	Solar Report to Oregon Legislature
UM 1811	Transportation Electrification Program Applications

- 2016 Smart Grid Report comments indicated a desire to compare/contrast these approaches

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Goals

"PGE [to] conduct a stakeholder process to develop metrics in which to compare cost effectiveness methodologies across all current and future DER and DSM efforts."

- Compare cost-effectiveness methodologies
- Identify where there are differences & discuss why
- Where there's a lack of clarity, see if there is stakeholder consensus
- Discussion should inform future analysis and/or rulemaking

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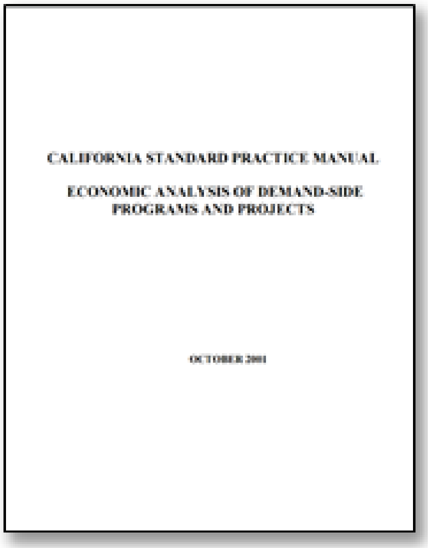
California Standard Practice Manual

- Framework used for most DSM programs around the country
- Outlines five perspectives:
  - Total Resource Cost:
    Utility and its customers
  - Program Administrator Cost:
    Utility only
  - Rate Impact Measure:
    Customers only
  - Participant Cost Test:
    Participants only
  - Societal Cost:
    Utility, customers, and non-customers


CALIFORNIA STANDARD PRACTICE MANUAL

ECONOMIC ANALYSIS OF DEMAND-SIDE PROGRAMS AND PROJECTS

OCTOBER 2001

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California Standard Practice Manual

Cost/Benefit Category	Total Resource Cost (TRC) Test	Societal Cost Test (SCT)	Program Administrator Cost (PAC)Test	Rate Impact Measure (RIM) Test	Participant Cost Test
Administrative costs	COST	COST	COST	COST	
Avoided costs of supplying electricity	BENEFIT	BENEFIT	BENEFIT	BENEFIT	
Bill Increases					COST
Bill Reductions					BENEFIT
Market participation revenue	BENEFIT	BENEFIT	BENEFIT	BENEFIT	
Capital costs to utility	COST	COST	COST	COST	
Capital costs to participant	COST	COST			COST
Environmental benefits	BENEFIT	BENEFIT			
Incentives paid			COST	COST	BENEFIT
Increased supply costs	COST	COST	COST	COST	
Market benefits	*BENEFIT*	*BENEFIT*	*BENEFIT*	*BENEFIT*	
Non-energy/monetary benefits		*BENEFIT*			*BENEFIT*
Revenue gain from increased sales				BENEFIT	
Revenue loss from reduced sales				COST	
Tax credits	BENEFIT				BENEFIT
Transaction costs to participant	COST	COST			COST
Value of service lost	*COST*	*COST*			*COST*

Italic indicates indirect/unmeasured cost-/benefit.

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Energy Efficiency

Key Attributes

Controllable	No
Injects power to grid	No
Shifts energy in time	Sometimes
Provides ancillary services	No
Non-distributed alternative?	No
Impact on load	Down
Behind-the-meter	Yes
Customer Owned	Yes
Carbon-free	Yes

Primary CE Test for Evaluation:

Total Resource Cost

Existing Docket

UM 1713

Existing Valuation/ Variations from CA

- Use of conservation adder
- Treatment of carbon benefits
- Capacity value

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Energy Efficiency

Key Considerations

- Cost-effective EE becoming more scarce

Areas of Uncertainty

- Locational value
- Capacity value
- How best to combine with other value streams
- Persistence of behavioral impacts

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Demand Response

Key Attributes

Controllable	Yes
Injects power to grid	No
Shifts energy in time	Sometimes
Provides ancillary services	Sometimes
Non-distributed alternative?	No
Impact on load	Both
Behind-the-meter	Yes
Customer Owned	Yes
Carbon-free	Yes

Primary CE Test for Evaluation:

Total Resource Cost

Existing Docket

UM 1708

Existing Valuation/ Variations from CA

The bulk of DR's benefit derives from the Avoided Cost of Capacity, consistent with CA. This value can swing significantly based upon:

- Choice of thermal resource
- A factor
- T&D avoided cost

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Demand Response

Key Considerations

- The 2016 IRP anticipates 78 MW of demand response resource by 2021.
  - Currently have ~13 MW enabled.
  - Numerous programs are planned to launch and ramp up quickly.
- Programs with high equipment or administrative costs and low avoided capacity per participant are challenging to prove cost effective

Areas of Uncertainty

- Avoided Cost of Capacity resource
  - SCCT: $120/kW per IRP
  - CCCT: $157/kW for flexible programs
- Availability Factor:
  - CA advocates calculating ELCC; PGE plans to pursue this route in the future.
  - For recent pilots, selected factors from CA programs with similar characteristics
- T&D avoided costs:
  - PGE applies distribution charge from Schedule 7 (4.035 cents per kWh)
- Attributes without detail:
  - Non-monetary benefits: we exclude
  - Value of lost service: gross estimate

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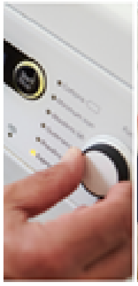
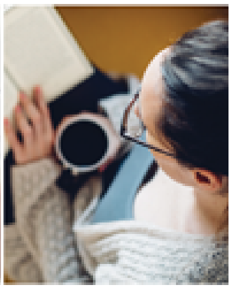
Demand Response

Costs and Benefits

Cost/Benefit Category	Total Resource Cost (TRC) Test Assignment	
Administrative costs		COST
Avoided costs of supplying electricity	BENEFIT	
Bill Increases		
Bill Reductions		
Market participation revenue	BENEFIT	
Capital costs to utility		COST
Capital costs to participant		COST
Environmental benefits	BENEFIT	
Incentives paid		
Increased supply costs		COST
Market benefits	BENEFIT	
Non-energy/monetary benefits	BENEFIT	
Revenue gain from increased sales		
Revenue loss from reduced sales		
Tax credits	BENEFIT	
Transaction costs to participant		COST
Value of service lost		COST





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Transportation Electrification

Key Attributes

Controllable	Yes
Injects power to grid	No
Shifts energy in time	Yes
Provides ancillary services	No
Non-distributed alternative?	No
Impact on load	Up
Behind-the-meter	Yes
Customer Owned	Yes
Carbon-free	No

Primary CE Test for Evaluation:
Rate Impact Measure

Existing Docket
UM 1811

Existing Valuation/ Variations from CA

Total Resource Cost (TRC) Test
- In addition to measures in RIM, TRC also includes impact to EV drivers including: avoided cost of gasoline, O&M savings, EV vehicle tax credits, and mass transit federal grants.
- CA adds: RPS costs, ancillary service costs, and GHG allowance costs.

Societal Cost Test (SCT)
- In addition to measures in TRC, SCT includes impacts on society including: reduced fuel emissions and cost of increased energy emissions.
- CA adds: health benefits and decreased oil use.

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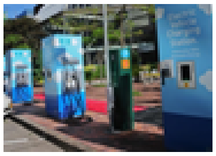
Transportation Electrification

Key Considerations

- Treatment of tax credits (state and federal) in RIM and TRC calculations.
- Market pricing versus cost of service pricing.
- One of the primary benefit streams in TRC and SCT is gasoline savings.
- Scope of analysis with respect to energy vs transportation sector.
- Use of RIM as primary CE test differs from approach for other DERs which use TRC.



Areas of Uncertainty

- EV is a new, growing market.
  - Customer preferences continue to evolve.
  - More difficult to forecast program impacts in a young industry.
- Charging behavior evolving
- Program impacts uncertain
- Direct vs portfolio impacts difficult to delineate
- Locational impacts are hard to project
- Cost and performance of electric vehicles and batteries continue to evolve
- New market with evolving preferences

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Transportation Electrification

Costs and Benefits

Cost/Benefit Category	Ratepayer Impact Measure (RIM) Test	
Administrative & O&M costs	COST	
Cost of supplying electricity	COST	
Bill Increases		
Bill Reductions		
Market participation revenue		
Capital costs to utility	COST	
Capital costs to participant		
Environmental benefits		
Incentives paid		
Increased electricity sales		BENEFIT
Market benefits		
Non-energy/monetary benefits		BENEFIT
Revenue gain from increased sales		
Revenue loss from reduced sales		
Tax credits		BENEFIT
Transaction costs to participant		
Value of service lost		

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Solar Generation

Key Attributes

Controllable	No
Injects power to grid	Yes
Shifts energy in time	No
Provides ancillary services	No
Non-distributed alternative?	Yes
Impact on load	Down
Behind-the-meter	Yes
Customer Owned	Yes
Carbon-free	Yes

Dockets

UM 1716, AR 603

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Solar Generation

Key Considerations

- Resource Value of Solar (RVOS) is structured to provide an accurate, time and location based compensation mechanism for the costs and benefits that solar generators bring to the grid.
- Elements are flexible and are theoretically unique to each individual project. This gives generators incentive to site projects in locations that are most beneficial to cost of service customers.
- Benefits for avoided capacity driven upgrades by the utility are compensated.

Areas of Uncertainty

- Stakeholders are currently working to determine the level of temporal and locational granularity that should be used to determine RVOS compensation price for each specific project.
- Multiple proposed elements (modified need of a utility to hedge fuel, solar impact on Mid-C market, avoided capacity-driven transmission and distribution upgrade) have not been previously calculated by any entity in Oregon.
- How does this new compensation mechanism get implemented into Oregon's many solar programs?

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Solar Generation

Costs and Benefits

Cost/Benefit Category	RVOS (and impact on compensation price)
Administrative costs	Decrement
Avoided costs of supplying electricity	Increment
Bill increases	N/A
Bill Reductions	N/A
Market participation revenue	Increment
Capital costs to utility	Increment (as avoided capacity)
Capital costs to participant	N/A
Environmental benefits	N/A
Incentives paid	N/A
Increased supply costs	N/A
Market benefits	Increment
Non-energy/monetary benefits	Increment for RPS
Revenue gain from increased sales	N/A
Revenue loss from reduced sales	N/A
Tax credits	N/A
Transaction costs to participant	N/A
Value of service lost	N/A

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Energy Storage

Key Attributes

Controllable	Yes
Injects power to grid	Yes
Shifts energy in time	Yes
Provides ancillary services	Yes
Non-distributed alternative?	Yes
Impact on load	Both
Behind-the-meter	Sometimes
Customer Owned	Sometimes
Carbon-free	No

Primary CE Test for Evaluation:
TBD

Existing Docket
UM 1751

Existing Valuation/ Variations from CA

- Battery valuation on PGE's system has been undertaken via ROM, which measures energy + ancillary value
- Battery capacity value treated as Avoided Cost (per CA)

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Energy Storage

Key Considerations

- HB 2193 requires a minimum of 5 MWh of energy storage procured by Jan 1 2020; max of ~39 MW.
- Also requires diversity of storage ownership, locations, and use cases to be explored.
- Battery cost declines from vendors (moderate) and quoted in media (aggressive).
- External consultants engaged to value various deployments on PGE's system, and to measure system reliability, customer bill management, locational benefits, and interaction between potential value streams.

Areas of Uncertainty

- Modeling the interactions of stacked benefit streams.
- Operational challenges of a shared asset, for behind-the-meter, customer sited batteries.
- Developing framework to compare benefits of battery with other resources, including thermal.

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Cross-Cutting Issues

Many points of uncertainty across analyses

- Choice of cost-effectiveness test
- Duration of analysis
- Input assumptions
- Locational value
- Value of ancillary services
- Value of resilience/reliability
- Equity
- Operation of shared assets (issues around when customer & energy company are operating assets)
- Cost trajectory of new technologies
- Choice of avoided cost resource

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	DR	EE	Storage	EVs	PV	DSG	CVR
Controllable	X	O	Δ	Δ	O	X	O
Injects power to grid	O	O	X	Δ	X	X	O
Shifts energy in time	Δ	O	X	X	O	O	O
Provides ancillary services	Δ	O	Δ	Δ	O	O	O
Non-distributed alternative?	O	O	X	O	X	O	O
Impact on load	↕	↓	↕	↕	↓	↓	↓
Behind-the-meter	X	X	Δ	Δ	Δ	X	O
Customer Owned	X	X	Δ	X	Δ	X	O
Carbon-free	X	X	Δ	O	X	O	X

X	Yes
O	No
Δ	Sometimes
↑	Up
↓	Down
↕	Both

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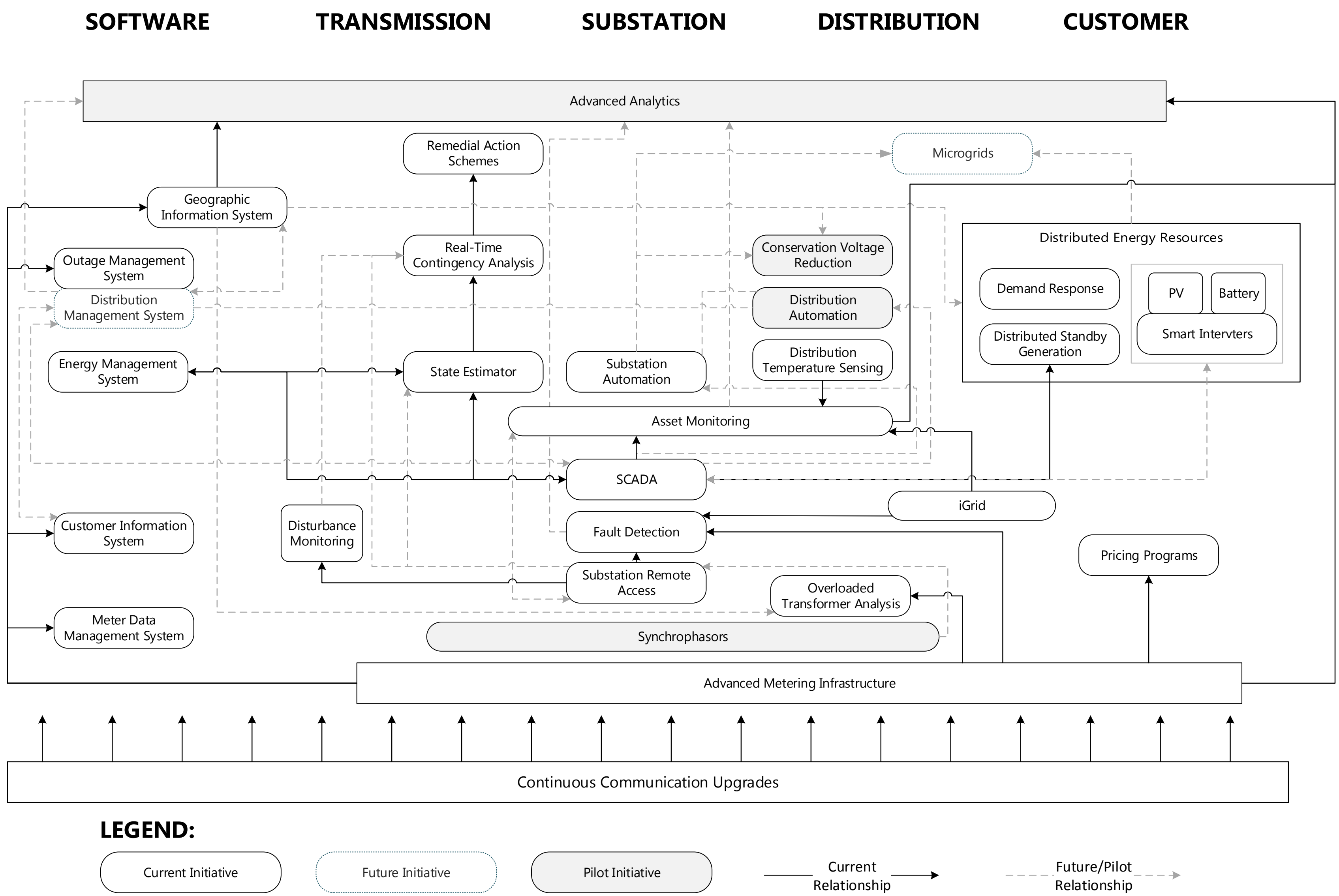
Appendix 7. Integration of Smart Grid Initiatives (visualization)



Appendix 8. Energy Partner Cost-Effectiveness Results

Cost-Effectiveness Results for the Energy Partner Demand Response Program

Presented to:

Portland General Electric

Portland General Electric
121 SW Salmon St,
Portland, OR 97204
April 29, 2016

Presented by:
Navigant Consulting, Inc.
1375 Walnut Street, Suite 100
Boulder, CO 80302
303.728.2500

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Table of Contents

Background

As of March 2016, Portland General Electric ("PGE") is running multiple pilots of new demand response (DR) programs. As PGE has yet to put a cost-effectiveness methodology in place for DR programs, the commission called for the development of cost effectiveness best practices in docket No. UM 1708. The report pointed out that "the utility and stakeholders will need to explore the development of a cost effectiveness methodology for DR programs." In response to the commission's directive, PGE held a workshop on DR cost-effectiveness in February 2016 and retained Navigant to inform a cost-effectiveness discussion for DR programs in Oregon. Navigant developed a white paper that proposes a cost-effectiveness methodology that satisfies the needs of PGE, the Commission and its stakeholders.[1] The white paper also acts as a conversation starter for quantifying the cost and benefits of other grid modernization initiatives.

PGE also retained Navigant to perform a cost-effectiveness analysis on its Energy Partner pilot program, which is the subject of this report. The methodology employed for this analysis is consistent with that proposed in the white paper described above, subject to data availability constraints. The results of this analysis will be shared with commission staff, and will be used to support PGE's cost-effectiveness filing for the pilot program.

Section I Introduction

PGE's Energy Partner program is a third-party administered, day-of load curtailment program targeted at commercial and industrial customers.[2] The program aims to provide a total of 25 MW of peaking capacity to the PGE system by July 1, 2017 by enabling 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).

Customers receive payments for enrolling to participate, and receive additional payments based on the number of events they participate in and load curtailed during each event (see Section 2.3). Customers also receive free access to energy monitoring software provided by EnerNOC, who has been contracted by PGE to administer the program. Customers that belong to the following rate schedules are eligible to participate in the pilot phase of the program:

- Schedule 89: Large manufacturing & general business
- Schedule 83 or 85: Large Businesses
- Schedule 49: Large business irrigation & drainage pumps
- Schedule 47: Small business irrigation & drainage pumps

[1] Portland General Electric, *A Proposed Cost-Effectiveness Approach for Demand Response.* Prepared by Navigant Consulting, Inc., April 2016

[2] See Portland General Electric, "Energy Partner – Get Paid to Help Meet Demand", https://www.portlandgeneral.com/business/get-paid-to-help-meet-demand/energy-partner

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

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

The remainder of this report includes the following sections:

- Section II outlines the cost-effectiveness methodology employed for this analysis. This includes a description of each of the cost and benefit streams that were quantified for this analysis, with data sources cited as appropriate
- Section III summarizes the results of the analysis by cost test and scenario for uncertain parameters.
- Section IV concludes findings from the analysis and provides a directive for further research required to more accurately assess cost-effectiveness of the Energy Partner program and other DR programs in general.

Section II Methodology

The white paper on DR cost-effectiveness lists seventeen cost and benefit streams that are included in DR cost-effectiveness tests. Navigant worked with PGE to determine which of these cost and benefit streams are quantifiable and applicable for the Energy Partner program, given current data availability.

Table 1 summarizes the five cost and benefit streams quantified in this analysis by cost test, which include administrative costs, avoided costs of supplying electricity, incentives paid, transaction costs to participants, and the value of service lost for participants.

This analysis does not include cost and benefit streams from the white paper that value energy-related impacts, as evaluation reports indicate that energy impacts are minimal for the Energy Partner program.[3] This analysis also does not include market participation revenue or non-monetary benefits, due to the lack of defined, quantifiable impacts associated with these benefit streams in the Northwest. These areas may be worth additional consideration in future research.

This analysis discounts the annual values[4] of each cost and benefit stream using a pre-tax weighted average capital cost (WACC) of 7.28% to quantify its net present value (NPV). This analysis also accounts for average transmission and distribution line losses of 5.77%. The

[3] Itron. *Portland General Electric Energy Partner Program Evaluation*. Draft Phase II Report. February 29, 2016.
[4] Annual cash flows are treated as real dollars in this analysis using an inflation rate of 2.01%.

benefit-cost ratio for each test is then calculated as follows:

$$Benefit - Cost\ Ratio = \frac{Total\ NPV\ of\ Benefit\ Streams}{Total\ NPV\ of\ Cost\ Streams}$$

The following subsections discusses each cost and benefit stream in greater detail.

Table 1: Summary of Cost-Effectiveness Tests and Proposed Value Streams for DR Programs[5]

Cost/Benefit Category	Total Resource Cost (TRC) Test	Program Administ-rator Cost (PAC)Test	Rate Impact Measure (RIM) Test	Participant Cost Test (PCT)
Administrative costs	COST	COST	COST	
Avoided costs of supplying electricity	BENEFIT	BENEFIT	BENEFIT	
Incentives paid	TRANSFER	COST	COST	BENEFIT
Transaction costs to participant	COST			COST
Value of service lost	COST			COST

2.1 Avoided Costs of Supplying Electricity

The avoided cost of deferred generation capacity expansion is the most valuable benefit stream in the case of the Energy Partner program.

PGE provided Navigant with annual avoided cost of capacity values from their expected 2016 Integrated Resource Plan (IRP) Avoided Cost Filing. These values were multiplied by the expected annual demand reduction of large commercial and industrial Energy Partner participants to produce annual avoided costs.[6] However, directly using these costs in this analysis assumes that Energy Partner can be optimized to realize the full, unconstrained benefits from event calls. This is not the case as the program is bound by a number of constraints, including the total number of hours it can be called on per season and the maximum number of events that can be called a day. These usage and availability constraints limit the ability of Energy Partner to respond to peak demand in the same manner as a traditional generator. As such, these avoided cost values are adjusted

[5] Cost and benefit designations for each stream are based on Navigant analysis and California Public Utilities Commission, Attachment 1: *2010 Demand Response Cost Effectiveness Protocols*

[6] Itron. *Portland General Electric Energy Partner Program Evaluation*. Draft Phase II Report. February 29, 2016. The expected annual demand reduction includes the value of avoided transmission and distribution line losses. The analysis assumes a realization rate of 86 percent in 2017, consistent with the Itron evaluation findings. This realization rate escalates to 100 percent by 2022, under the assumption that a third-party administered program will deliver 100 percent of committed capacity in a pay-for-MW program once the program reaches maturity.

downward to reflect these limitations. This is consistent with the approach proposed in the white paper.

California's Public Utilities Commission (CPUC) outlines a framework for adjusting avoided costs using five adjustment factors. Of these, three are applicable to the Energy Partner program, as follows:

2.1.1 Availability (A Factor)

The availability factor is interpreted as the percent of overlap between program availability hours and forecasted periods of highest demand or load loss. The A factor is difficult to calculate for a given program without detailed analysis.

Given data availability constraints for this analysis, Navigant identified a range of A factor values used in secondary literature by the California investor owned utilities. To account for the uncertainty surrounding the A factor parameter, Navigant ran a sensitivity analysis on this range of A factor values to better understand the impact that variations have on the benefit-cost ratio results. Navigant used 25 to 85 percent for the sensitivity analysis, based on Southern California Edison's (SCE) 2012-2014 DR application filing to the CPUC.[7] This variability represents differences in the frequency and duration of DR event calls permitted by contractual agreement with customers across different types of DR programs.

Navigant then used Pacific Gas and Electric's (PG&E) cost-effectiveness analysis as a secondary reference.[8] Within PG&E's portfolio, the PeakChoice program has 75 hours of availability annually, which resembles Energy Partner's 80 hours. PG&E estimated A factors of 41 and 82 percent for the PeakChoice program, depending on the assumption made about what to use for the historical load hours. The discrepancy in these two values indicates the wide range uncertainty associated with estimating A factors, without a detailed analysis. For the purposes of the Energy Partner analysis, Navigant recommends using an average of these values, at 60 percent.

A more detailed analysis on the A factor value for the Energy Partner program is recommended for future work, as discussed in Section 4.1.

2.1.2 Notification Time (B Factor)

The B factor is typically applied to programs that are called a day in advance of the actual event period, as differences in weather and demand forecasting can result in different curtailment impacts the day of the event. Since Energy Partner is a day-of program, the B factor is 100% for this analysis. This is consistent with the CPUC framework.

2.1.3 Trigger (C Factor)

The C factor represents how flexible the event call trigger is. Examples of triggers are day-

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[7] Southern California Edison Company. *Demand Response Measurement and Evaluation, Program Enrollment and Load Impacts, Cost-Effectiveness, and Ratemaking Proposal. Application No. A.11-03-003*. March 2011. SCE developed their A factor values for various DR programs based on overlap between program availability and the top 250 historical load hours, weighted by the highest load hours.

[8] PG&E Demand Response July 26, 2011 Cost-Effectiveness spreadsheets. Found on California Public Utilities Commission website. < http://www.cpuc.ca.gov/General.aspx?id=7023>.

ahead market prices, which are dependent on certain conditions.[9] The CPUC recommends that programs with flexible triggers should have a higher avoided cost of capacity value than programs with more specific trigger conditions. The Energy Partner program has insufficient data on operating history to credibly calculate the trigger factor. A strict definition of trigger conditions, combined with more extensive operational history, would allow calculation of this factor.

2.2 Administrative Costs

EnerNOC recruits participants, installs curtailment software and hardware, processes incentive payments, and provides technical support to participants on PGE's behalf. As such, neither PGE nor customers incur equipment capital costs, as PGE pays EnerNOC a flat fee to administer the program through all stages of implementation. In addition to an annual flat fee, PGE makes program incentive payments directly to EnerNOC. A portion of these incentive payments are passed on to participants and the remaining portion is kept by EnerNOC as part of the variable cost of administering the program. EnerNOC has not provided the exact portion of incentive payments kept by EnerNOC as administration costs. However, Navigant estimates that EnerNOC keeps roughly 50 percent of the incentive payments made by PGE.[10] The total administrative cost stream for this analysis is therefore the sum of the annual flat fee and 50 percent of incentive payments made by PGE. Incentive payments are discussed in greater detail in Section 2.3.

2.3 Incentive Payments

Energy Partner participants received two types of incentive payments from PGE via EnerNOC. The first is a reservation payment received on a six-month basis, based on the amount of capacity a customer nominates into the program. The second is an event payment received for actually curtailing load during an event call. PGE provided Navigant with these incentive payment costs based on their planned program budget for 2017 and 2018. As discussed in Section 2.3, only a portion of these payments are actually received by the customer, while the rest is absorbed by the program administrator. As discussed above, Navigant approximates that 50 percent of incentive payments made by PGE are received by the customer.

2.4 Transaction Cost and Value of Service Lost

Transaction costs incurred by the participant represent opportunity costs associated with education, equipment installation, program application processing, audits, evaluations, program planning, and program operation. These may overlap with capital costs and program administrative costs.

The value of services lost is a cost stream that represents any productivity losses and comfort costs associated with a utility program. In the context of a DR program for example, an event that shuts off space heating during a cold day could cause some discomfort to customers.

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[9] San Diego Gas & Electric Company. *Data Response of San Diego Gas and Electric Company (U 902 M) Requiring Additional Cost-Effectiveness Information.* February 23, 2009.

[10] Based on Navigant's review of competitive bids from commercial and industrial DR aggregators in 2016.

Participant transaction costs and the value of services lost are collectively treated as “indirect costs” in this analysis. These indirect costs can be calculated as a percentage of financial incentives received by participating in the program. That is to say, some percentage of incentives received are lost to opportunity costs and loss of comfort. It is widely recognized that this is a difficult metric to quantify.[11] To account for this uncertainty, Navigant ran a sensitivity analysis on the benefit-cost ratios for a range of percentage values between 0 and 100 percent and presents results based on that range.

Within this range, assuming indirect costs as 50 percent of incentives for the Energy Partner program is consistent with what other utilities use for similar DR program types. Hence, this is the recommended value for this current analysis.

Section III Results

3.1 Total Resource Cost (TRC) Test

Table 2 summarizes the results of the TRC test for a range of A factor and indirect cost percentage values. For the A factor sensitivity, the percentages range from 25 percent to 85 percent, reflecting the range of A factors available from Southern California Edison’s 2012-2014 DR application filing to the CPUC. For the indirect cost sensitivity, the percentage values range from 0 percent to 100 percent, indicating the portion of incentive value that is experienced as a cost to participants.

As discussed above in Sections 2.1.1 and 2.4, 60 percent and 50 percent are the recommended A factor and indirect cost values, respectively, for considering the Energy Partner program results.

Table 2: Total Resource Cost Test Results

Indirect Cost Sensitivity → / ↓ A Factor Sensitivity	0%	25%	50%	75%	100%
30%	0.87	0.71	0.59	0.51	0.45
45%	1.31	1.06	0.89	0.77	0.68
60%	1.74	1.41	1.19	1.03	0.90
75%	2.18	1.77	1.49	1.28	1.13
85%	2.47	2.00	1.68	1.45	1.28

3.2 Program Administrator Cost (PAC) and Rate Impact Measure (RIM) Tests

Table 3 summarizes the results of the PAC and RIM tests for a range of A factor and indirect cost percentage values. These tests produce the same results in this analysis and are

[11] US Environmental Protection Agency. *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers.* November 2008.

therefore presented here together. As shown in Table 1, the PAC and RIM tests both consider administrative costs and incentives paid as a cost, and avoided costs of supplying electricity as a benefit. These tests do not consider transaction costs or value of service lost to participants and, thus, do not vary by the indirect cost sensitivity.

Table 3: PAC and RIM Cost Test Results

Indirect Cost Sensitivity → / ↓ A Factor Sensitivity	0%	25%	50%	75%	100%
30%	0.45	0.45	0.45	0.45	0.45
45%	0.68	0.68	0.68	0.68	0.68
60%	0.90	0.90	0.90	0.90	0.90
75%	1.13	1.13	1.13	1.13	1.13
85%	1.28	1.28	1.28	1.28	1.28

3.3 Participant Cost Test (PCT)

Table 4 summarizes the results of the PCT for a range of A factor and indirect cost percentage values. As shown in Table 1, the PCT test considers incentives as a benefit, and transaction costs and value of service lost as costs to the participant. This test does not consider avoided costs of supplying electricity or program administrative costs. As such, at an indirect cost value of zero percent, there are zero costs and the benefit-cost ratio calculation is shown as not applicable.

Table 4: PCT Cost Test Results

Indirect Cost Sensitivity → / ↓ A Factor Sensitivity	0%	25%	50%	75%	100%
30%	N/A	4.00	2.00	1.33	1.00
45%	N/A	4.00	2.00	1.33	1.00
60%	N/A	4.00	2.00	1.33	1.00
75%	N/A	4.00	2.00	1.33	1.00
85%	N/A	4.00	2.00	1.33	1.00

Section IV Conclusions and Directions for Future Research

Based on the results presented above, Energy Partner program is cost effective under the following conditions:

- When the A factor value is approximately equal to or greater than 45 percent and the indirect cost is less than 50 percent, or when the A factor values is approximately equal to or greater than 60 percent for all indirect cost values under the TRC test.
- When the A factor value is greater than 60 percent under the PAC and RIM tests.
- For all non-zero indirect cost values under the PCT test.

With the recommended A factor and indirect cost values of 60 percent and 50 percent, respectively, the Energy Partner program is cost-effective under the TRC and PCT tests. It falls slightly below 1 for the PAC and RIM tests.

The remainder of this section discusses additional research that would provide greater certainty in future cost-effectiveness analyses for the Energy Partner program.

4.1 Develop Detailed A Factor Calculations

PGE could more precisely develop specific A factor calculations for Energy Partner and other demand response programs with the appropriate data. These data include:

- Consulting resource dispatch engineers to determine the threshold for the top number of hours in which demand response is most likely to be called as a resource.
- Using historical data to determine when these peak hours occur, and assign a dispatch importance weight to each of those hours.
- Collecting performance history from Energy Partner to determine the hourly load impacts of the program.

Derivation of the A factor would involve comparing hourly load impacts of Energy Partner with weighted peak hours, within the program's availability constraints, to develop an A factor ratio.

4.2 Research Indirect Costs

The current analysis assumes that the indirect program participation costs are a consistent percent of incentives for all participants. However, the specific manner in which participants are curtailing load (e.g., automatic versus manual) can have different transaction costs and the types of loads that are curtailed (e.g., HVAC versus lighting) may provide different amounts of customer value. Future surveys of participants could provide information to more accurately quantify these factors.

4.3 Evaluate Additional Benefit Streams

Future analyses may consider additional benefit streams from market participation revenue, ancillary service benefits, and non-monetary benefits. These benefits have not been included in this current analysis due to their limited applicability to the current Energy Partner program and lack of defined, quantifiable impacts associated with these benefit streams in the Northwest.

Appendix 9. Commercial & Industrial DR Program Redesign

NAVIGANT

Commercial & Industrial Demand Response Program Redesign

Presented to:

PGE

Portland General Electric

Portland General Electric

121 SW Salmon St,

Portland, OR 97204

March 23 2017

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Table of Contents

Executive Summary

PGE's current Integrated Resource Plan includes a commitment to provide 77 MW of generation capacity deferral from demand response (DR) across all customer sectors by 2020,[1] with a significant portion coming from the commercial and industrial (C&I) sectors. However, PGE has faced challenges building C&I DR capacity through its existing C&I DR portfolio, consisting of the Energy Partner program and Schedule 77. This study identifies recommendations for 1) retaining the existing customers on PGE's Energy Partner program and Schedule 77, 2) expanding the reaches of PGE's C&I DR capacity, and 3) maintaining the operational value of PGE's DR resource for generation deferral capacity over a targeted set of peak hours.

Findings

Since the program's inception in 2013, the Energy Partner program has been unable to meet its MW goals and, in fact, has been losing capacity over the past two years. PGE's service area is a difficult one to develop an effective C&I DR resource, due to a variety of factors including limited industrial load, the need for a dual peaking resource, and limitations on participation from emergency generation and direct access customers. Compounding this difficult business environment, the program's aim to deliver a firm and valuable resource to the Company has resulted in relatively strict rules for participation and performance that have limited enrollment and the number of MW that customers are willing and able to contribute.

The following are specific findings relating to 1) the PGE customer base and operating environment, 2) the Energy Partner program structure, and 3) the program delivery.

PGE Customer Base and Operating Environment:

1. PGE's service area has fewer large industrial loads that are able to provide significant amounts of curtailment than other regions.
2. PGE is losing potential large C&I demand response opportunities due to large customers choosing alternative providers.
3. Limiting the aggregation of multiple meters on a single customer site limits the number of customers eligible for participation.
4. PGE's program restricts the participation of emergency generation, which is a significant source of MW in other DR programs around the country.

Program Structure:

1. Current participants are satisfied with most aspects of the program.
2. Having dual peaks creates unique and significant challenges for implementing demand response.
3. The duration of the event windows presents a challenge for the program implementer and some customers.
4. PGE's peak hours are not necessarily coincident with C&I customer peak hours.
5. The 10-minute notification time is a perceived barrier for customers considering enrolling in the program and contributes to increased program costs.
6. The 10-minute notification time is not a significant barrier for customers in practice.
7. Enabling more customers with automated curtailment would increase the curtailment

[1] PGE plans to expand its DR resources to 77 MW (winter) and 69 MW (summer) through 2020, with continued growth in later years. Portland General Electric, *2016 Integrated Resource Plan*, November 2016.

available from both non-participants and participants alike, although at a higher program cost.

Program Delivery:

1. Corporate social responsibility and "doing the right thing" is the primary motivator for a majority of participants, with the financial incentive typically serving as a secondary driver.
2. The majority of non-participants interviewed reported a perception that the costs of participating in the program outweigh the value, particularly in terms of the perceived impact on operations.
3. Customers in the region are less familiar with DR than in regions with mature DR programs and would benefit from more education in the initial outreach process, as well as throughout the program.
4. Fall-off of customer load curtailment over the course of participation may be improved through customer education and ongoing engagement.
5. Requiring additional metering equipment provides customers with real-time energy information, but the value of real-time versus next-day information for customers may not merit the increased program equipment costs.
6. Opportunities exist for impactful coordination with the Energy Trust of Oregon's Strategic Energy Management (SEM), but require strategic effort from PGE.
7. KCMs contribute to customer enrollment, although the role of KCMs could be enhanced for more involvement in the marketing and recruitment process.

Recommendations

The recommended changes in the design of PGE's C&I DR program offerings reflect changes in PGE's priorities for DR, as well as shifts across the industry to a more customer-oriented resource. Relative to the resource-centric approach taken to design the current program, this new DR philosophy emphasizes customer needs including flexibility within the program design, enhanced customer engagement, and an enhanced value proposition for the customer to facilitate greater participation from customers within their operations requirements.

The following are specific findings relating to 1) the target market, 2) the proposed program structure, and 3) the program delivery.

Target Market:

PGE should explore the following options with vendors for an expanded target market during the procurement process:

1. Non-industrial/process loads at large C&I customers, such as lighting and HVAC
2. Medium-size C&I customers (200 kW to 1+ MW peak load)
3. Small-size C&I customers (<200 kW peak load)
4. Site aggregation
5. Direct access customers

Program Structure:

1. Allow more flexibility across seasons and within seasons.
2. Prioritize the hours and conditions that PGE expects to utilize the DR resource, and allow customer flexibility outside of those hours.
3. Facilitate partial credit for partial participation.
4. Relax the notification time requirement for participation.
5. Emphasize automated curtailment, where possible, but continue to support both manual and

automated curtailment.

6. Revisit the methodology used for determining a customer's baseline to avoid penalizing customers with variable load.

Program Delivery:

1. Identify one or more partner vendors that will provide technical expertise, implementation field staff, and ongoing customer support for a C&I DR program, while supporting PGE's objectives for a flexible customer-centric program in which PGE maintains the primary relationship with the customer.
2. Focus the program marketing and delivery around the benefits to the customers.
3. Enhance education for both participants and non-participants.
4. Pursue opportunities for collaborating with the SEM program that minimize customer barriers and integrate into the Energy Trust's day-to-day processes with minimal overhead.
5. Increase marketing to medium-size customers (200 kW to 1+ MW peak load).
6. Evaluate options for using existing interval meters to lower program equipment costs.
7. To avoid fall-off of customer load curtailment, set initial load curtailment targets low and educate customers more fully on how DR may affect their operations.
8. Leverage existing and new channels for broader and more continuous customer engagement.

Section I Introduction

PGE's current Integrated Resource Plan includes a commitment to provide 77 MW of generation capacity deferral from demand response (DR) across all customer sectors by 2020,[2] with a significant portion coming from the commercial and industrial (C&I) sectors. PGE's C&I DR portfolio currently consists of the Energy Partner program with 10-15 megawatts (MW)[3] and Schedule 77 with 1.8 MW. Since the inception of the Energy Partner program in 2013, the Energy Partner program has been unable to meet its MW goals and, in fact, has been losing capacity over the past two years. Given the challenges that PGE has encountered with achieving target DR capacity from the C&I sectors, the objectives of this study are to identify recommendations for 1) retaining the existing customers on PGE's Energy Partner program and Schedule 77, 2) expanding the reaches of PGE's C&I DR capacity, and 3) maintaining the operational value of PGE's DR resource for generation deferral capacity over a targeted set of peak hours.

To support the findings in this study, Navigant conducted interviews with the following stakeholders:

- PGE program staff
- Energy Partner program manager at the program implementer (EnerNOC)
- Strategic Energy Management (SEM) program manager at the Energy Trust of Oregon (Energy Trust)
- 10 participants
- 10 non-participants, including 5 customers currently participating in the SEM program, 4 customers who had previously declined to participate in the program, and 1 former participant
- This study is organized into the following sections: **Section II: Findings** presents the findings from the interviews noted above, as well as Navigant's review of relevant secondary

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[2] PGE plans to expand its DR resources to 77 MW (winter) and 69 MW (summer) through 2020, with continued growth in later years. Portland General Electric, *2016 Integrated Resource Plan*, November 2016.

[3] EnerNOC's expected nominations for the Energy Partner program are 13.5 MW for Winter 2016/2017 and 11.3 for Summer 2017.

resources from PGE and other jurisdictions, including benchmarking results comparing PGE's C&I customer base with other utilities around the country.

- **Section III: Recommendations** discusses recommendations for refining PGE's C&I DR program offerings, based on the findings in Section II and best practice programs at other utilities, as well as recommendations for conducting the procurement process.
- **Section IV: Summary** provides a summary overview of the issues and recommendations.

Section II Findings

PGE initially designed the Energy Partner and Schedule 77 programs to maximize the value of the resource to PGE's system, with fast response time and comprehensive windows of availability, as shown in Figure 1. For the reasons discussed in this section, these objectives are difficult to achieve in a robust, cost-effective program within PGE's service area.

A key theme expressed by both PGE and customers was the desire for more flexibility within the program design and eligibility requirements to facilitate broader customer participation and increased customer satisfaction. In other words, moving from a "one size fits all" program to one with more options for when and how customers participate.

Figure 1. Philosophy of Program Design: Current Program

Source: Navigant, 2017.

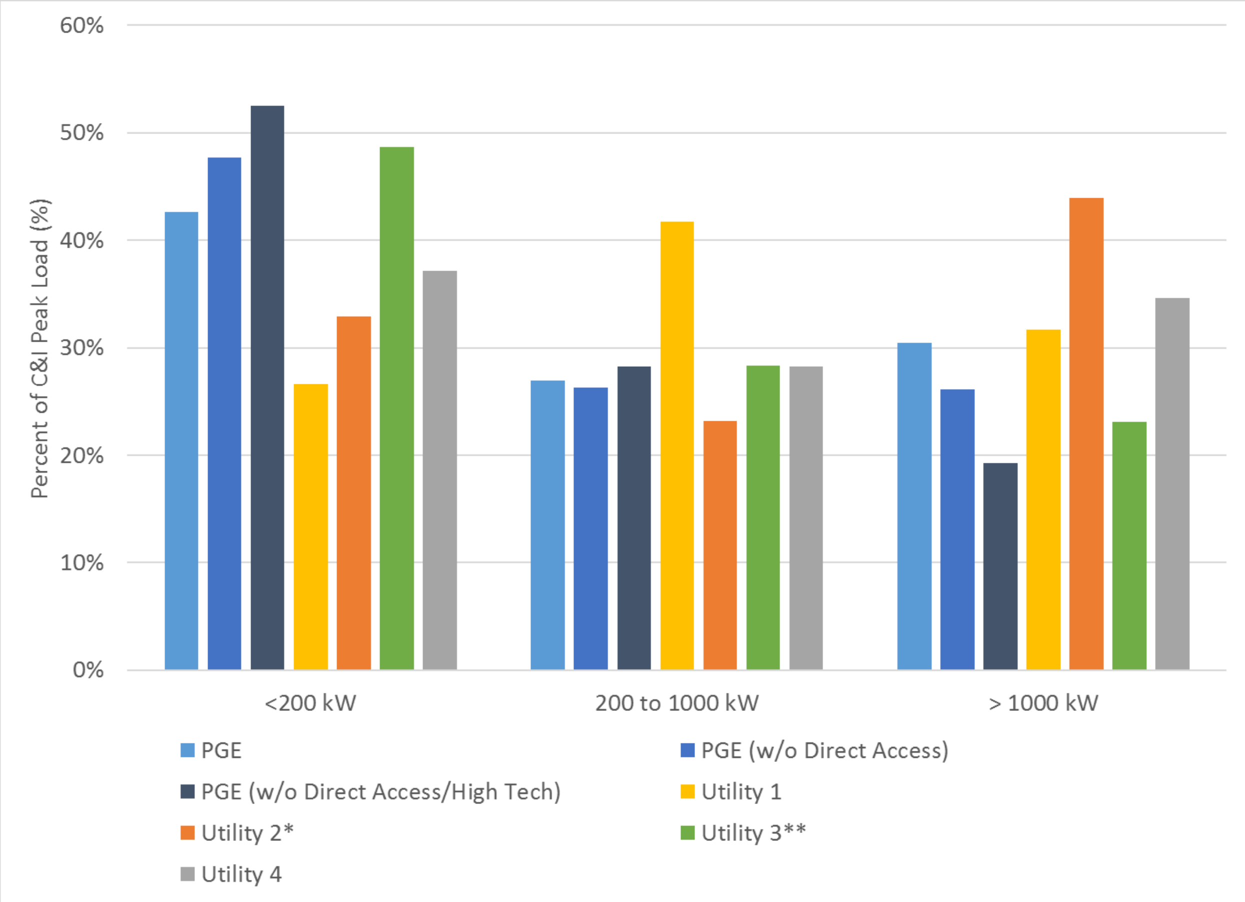
2.1 PGE Customer Base and Operating Environment

The following section discusses the finding relating to the market characteristics and system requirements within which the Energy Partner program operates.

1. **PGE's service area has fewer large industrial loads that are able to provide significant amounts of curtailment than other regions.** Other utility programs around the country often rely on just a few very large customers to provide the bulk of curtailment. For example, Xcel Energy Colorado currently has roughly 200 MW out of the 300 MW available from their C&I program through just two customers. Similarly, Oncor's early-stage C&I DR program had 9 MW of 11 MW from a single customer. Compared to these other regions, PGE's customer base has fewer large industrial customers who can shift or shed load during PGE's peak times. For example, one-third of PGE's demand from customers with greater than 1 MW peak load is from high-tech manufacturing customers. These customers have significant load and would be prime candidates for participation; however, they are generally reluctant to participate due to the limited options available for participation without impacting production, the high consequences of production disruption, and the relatively limited benefits of participation in comparison to these factors. Similar barriers exist for hospitals. Navigant has seen these challenges with enrolling high-tech manufacturing and hospitals in other service areas, as well.

Figure 2 shows the percent of PGE's C&I customers by size compared to other utilities with C&I DR programs. After factoring out high-tech manufacturing and direct access (discussed in below) customers who are unable to participate, PGE has a significantly smaller proportion of large C&I customers than other utilities.

Figure 2. Benchmarking Comparison of PGE C&I Peak Load to Other Utilities by Size



Source: Navigant, 2017 and utility data.

** Utility 2 based on Average Monthly Load data and size breakdowns of <500kW, 500-1000 kW and >1000 kW*

*** Utility 3 based on size breakdowns of <300 kW, 300-1000 kW and >1000 kW*

2. **C&I load is declining due to large customers choosing alternative providers**. As an example, two customers recently left the program when their companies switched to direct access and were no longer eligible for the program. Based on their experience in other jurisdictions, EnerNOC contends that these customers and potentially other national chains would return to the program if direct access customers were eligible; however, PGE would need to work with regulators to determine if and how program incentives could be appropriately allocated to non-PGE customers. Figure 2 indicates the magnitude of impact from excluding direct access customers.
3. **Limiting the aggregation of multiple meters on a single customer site limits the number of customers eligible for participation**. EnerNOC does not currently permit aggregation of metered locations on a customer site below a certain size threshold, due to the cost of installing the separate meters that EnerNOC requires for participation at each metered location on the customer site. This presents a significant barrier for the participation of certain customers, such as campus-like customers with multiple smaller facilities on a single site.

4. **PGE's program restricts the participation of emergency generation, which is a significant source of MW in other DR programs around the country.** Within PJM's entire DR portfolio, generators alone comprise 12 percent of nominated capacity.[4] As another example, within Duke Energy Progress's C&I Demand Response Automation Program, generators comprise more than 75 percent of their summer DR impacts and more than 90 percent of their winter DR impacts.[5] PGE recently changed the program rules, such that the Energy Partner program may be marketed to customers who also participate in PGE's DSG program. However, the customer is only permitted to participate in Energy Partner with load, rather than the generators. EnerNOC estimated that the additional curtailment that could be achieved if EPA compliant generators were eligible is between 3 and 4.5 MW. While PGE does not plan to permit the use of generators for DR, it is worth noting that the exclusion of this resource limits available MW, relative to other DR programs. The limitation of generation also impacts participation from segments with sensitive loads like hospitals and high-tech customers, who are reticent to curtail end use loads.

2.2 Program Structure

The following section discusses findings related to the structure of PGE's existing Energy Partner program, including program parameters like event timing and duration.

1. **Current participants are satisfied with most aspects of the program.** Participants responded with an average of 8.4 when asked how satisfied they are with the Energy Partner, where a 0 meant they are extremely dissatisfied and a 10 meant they are extremely satisfied. Customers also expressed general satisfaction in their interactions with EnerNOC, PGE, and their KCM.

2. **Having dual peaks creates unique and significant challenges for implementing demand response.** PGE's demand response targets are similar in the winter and the summer through at least 2021. Thus, PGE's current program requires customers to enroll for both winter and summer. While customers are able to nominate different load amounts in each season, it is hard for some customers to offer curtailment in both summer and winter. As an example, three of the four prospective non-participants interviewed mentioned that participation would be significantly harder for them in the winter than in the summer.

   Implementers must enroll customers who are able to curtail in both seasons or incur additional costs enrolling customers who can only participate in one season. Although program delivery costs increase by as much as 40 percent when providing curtailment in both summer and winter, PGE's avoided costs are split across seasons, which means that an implementer must be able to provide almost double the curtailment for half of the avoided cost value.

3. **The duration of the event windows presents a challenge for the program implementer and some customers.**[6] The duration of the event window is much larger than in most other programs (i.e., typically two to four hours), although the vast majority of PGE's events over the past several years have occurred in the 4-7 p.m. timeframe. The broad event windows limit the pool of candidates who are available to curtail across all possible event hours and incurs additional costs on the part of the program implementer to identify those candidates or bear the risk that less-suitable companies will not be able to provide sufficient demand reduction if events are called outside of the 4-7 p.m. timeframe.

4. **PGE's peak hours are not necessarily coincident with C&I customer peak hours.** PGE's

[4] http://pjm.com/~/media/markets-ops/dsr/2016-demand-response-activity-report.ashx
[5] Navigant analysis, Duke Energy Progress Commercial, Industrial and Governmental Demand Response Automation Program, Program Year 2015.
[6] 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.

peak occurs later in the day than for many utilities with large C&I DR programs. The 4-7 p.m. timeframe works well for some C&I customers that are changing shifts during this time or have fewer customer occupancy concerns outside of their core business hours. However, it also limits participation from customers, particularly commercial, who operate primarily 9 a.m. to 5 p.m. and either have limited load available to curtail or would need to pay someone overtime to manage the event curtailment. As discussed in the recommendations below, some customers thought that automated curtailment could help minimize this barrier.

None of the participants expressed concerns about participating in morning events, which is likely due to the fact that PGE has only called one morning event in the history of the program. However, the requirement that customers must be available to participate in both the morning and evening means that the program heavily favors 24/7 customers and can present a perceived barrier for non-participants.

5. **The 10-minute notification time is a perceived barrier for customers considering enrolling in the program and contributes to increased program costs.** Requiring the ability to curtail within ten minutes limits the pool of customers eligible for the program and increases program delivery costs through increased automation needs, added risk absorbed by the implementer, and more limited enrollment options. Several non-participants said that they would need at least an hour to curtail load, particularly without automation.
6. **The 10-minute notification time is not a significant barrier for customers in practice.** In practice, EnerNOC generally provides customers with an alert that an event may be coming, then gives customers at least three hours of advance notice. EnerNOC tells customers to expect two to four hour notice, but they may need to perform in ten minutes in rare circumstances. Current participants generally seem satisfied with this arrangement.
7. **Enabling more customers with automated curtailment would increase the curtailment available from both non-participants and participants alike, although at a higher program cost.** Manual curtailment with 10-minute notification is challenging for many customers, who are shutting down multiple loads, and a perceived barrier for non-participants. Furthermore, the late afternoon and evening timing for PGE's events means that many C&I customers need to pay someone overtime to manually curtail load during events. With automation, these customers could potentially still participate after the main business hours.

   Half of the non-participants interviewed said that automation would increase the chances of their participation. PGE also recently worked with a customer interested in participating in Energy Partner who ultimately decided not to participate because they wanted automation and were not able to make it pencil out with PGE and the Energy Trust.

2.3 Program Delivery

The following section discusses the findings related to the program delivery, including marketing and outreach strategies, as well as contracting considerations.

1. **Corporate social responsibility and "doing the right thing" is the primary motivator for a majority of participants, with the financial incentive typically serving as a secondary driver.** Only two of the ten participants interviewed responded that financial benefit is their primary driver for participation. Thus, the financial incentive is an important factor, but is not the only factor driving customers to participate, and often it is not sufficient to serve as the sole benefit to customers.
2. **The majority of non-participants interviewed reported a perception that the costs of participating in the program outweigh the value, particularly in terms of the perceived impact on operations.** Non-participants also expressed concern with the costs of enablement, occupant comfort, and staff time during events. For example, the Energy Trust of Oregon cited that their SEM customers historically do not see enough upside benefit from the program for them to spend time setting up DR at their site. This fits with EnerNOC's findings that reasons provided by customers who are "not interested" in the program included: *too much work*, *too disruptive*, *does not see how it fits into operations*, and *not worth it*. It should

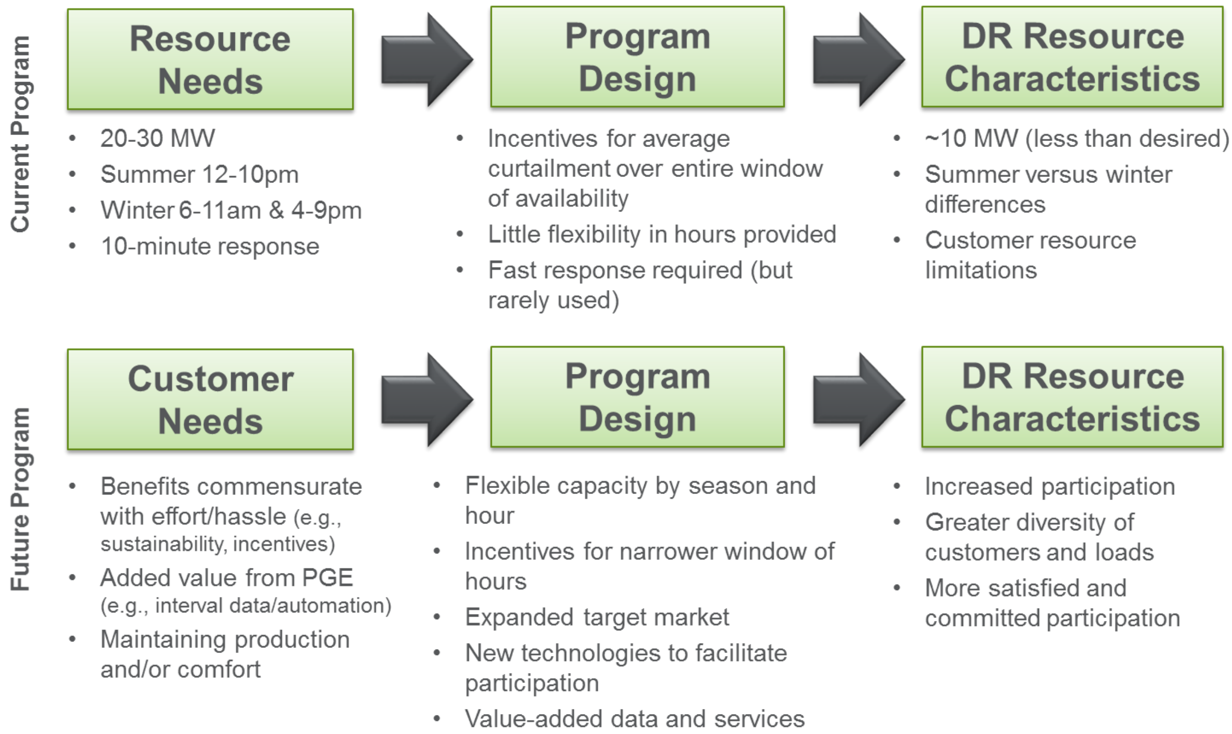
be noted that some customers are unlikely to participate, regardless of the financial value proposition that the program offers, such as customers with sensitive 24/7 operations.

3. **Customers in the region are less familiar with DR than in regions with mature DR programs and would benefit from more education in the initial outreach process, as well as throughout the program.** Both participants and non-participants alike expressed interest in having more resources available to help them and their stakeholders (i.e., customers, staff, and internal management) understand a range of topics, including how the program works; the value of the program to their organization and society; the potential drawbacks and costs of participating; and how to optimize their curtailment strategy. This lack of education might also be a key driver for the customer perceptions discussed in #2 above.
4. **Fall-off of customer load curtailment over the course of participation may be improved through customer education and ongoing engagement.** Half of the participants interviewed reported revising their initial curtailment strategy to lower targets and some reported still having issues meeting their targets. Part of these changes resulted from changes in the customer's operation, while part of these changes resulted from customers learning more about DR and how it affects their facility. For example, one customer had been initially unaware of how their curtailment strategy would be impacted in the winter versus the summer.
5. **Requiring additional metering equipment provides customers with real-time energy information, but the value of real-time versus next-day information for customers may not merit the increased program equipment costs.** EnerNOC currently requires that customers install a separate meter for participation, even if customers already have an interval meter. This separate meter provides customers with near-real-time energy information, as opposed to the next-day information that PGE's existing interval meters would provide. During interviews, only three of the ten participants mentioned using the system in real-time during events. The other comments from participants suggest that a system providing next-day information would largely suit customers' needs.
6. **Opportunities exist for impactful coordination with the Energy Trust of Oregon's Strategic Energy Management (SEM), but require strategic effort from PGE.** Energy Trust of Oregon and PGE concur that the SEM program is a good channel for informing C&I customers about DR, given that SEM participants tend to have high acceptance and awareness of energy-related opportunities. One Energy Partner participant even said that the change in their organization's culture and thinking about energy use through the SEM program paved the way for them to enroll in Energy Partner. However, successful collaboration with the SEM program will need to overcome barriers relating to limited staff time, customer and contractor education, customer fatigue, and technical integration. Recommendations for overcoming each of these are discussed in Section 3.3 below.
7. **KCMs contribute to customer enrollment, although the role of KCMs could be enhanced for more involvement in the marketing and recruitment process.** KCMs currently manage about half of the current participants, with the other half unmanaged. EnerNOC leads the enrollment process, with a hand-off mechanism between the KCMs and EnerNOC. With training, clearly defined expectations, and aligned incentives, KCMs could likely play an enhanced role in engaging customers in the program.

Section III Recommendations

The section below discusses recommended changes in the design of PGE's C&I DR program offerings to reflect changes in PGE's priorities for DR, as well as shifts across the industry to a more customer-oriented resource. Relative to the resource-centric approach taken to design the current program, this new DR philosophy emphasizes customer needs including flexibility within the program design, enhanced customer engagement, and an enhanced value proposition for the customer to facilitate greater participation from customers within their operations requirements.

Figure 3. Philosophy of Program Design: Future Program



Source: Navigant, 2017.

3.1 Target Market

Historically, the target market for the Energy Partner program has been larger C&I customers, particularly in the industrial sector. Expanding the targeted reach of the program to additional market segments can contribute to significant incremental DR capacity if certain barriers are removed. PGE should explore the following options with vendors for an expanded target market during the procurement process:

1. **Non-industrial/process loads at large C&I customers, such as lighting and HVAC:** Enabling additional types of load at the customer site could increase nominations from existing participants and entice participation from customers with sensitive processes that might not otherwise participate. For example, three of the ten participants interviewed responded that they could potentially curtail more load at their facility by expanding their curtailment strategy beyond process equipment to other loads like lighting, particularly with automation or assistance upgrading equipment. Hospitals and high-tech customers, who are otherwise unwilling or unable to participate by curtailing process-related loads, may consider curtailing non-essential HVAC and lighting in office spaces with the appropriate value proposition for doing so.

2. **Medium-size C&I customers (200 kW to 1+ MW peak load):** PGE has roughly the same amount of load from medium-size C&I customers as from larger customers with 1+ MW (see Figure 2). New strategies are emerging for engaging these customers in DR, as vendors and utilities around the country are looking beyond large C&I customers. These implementation strategies include distributed, networked, high-tech, relatively low-cost communication and control technologies that can communicate back to a central control center. One example of a vendor that participates in this market is Encycle. Smart thermostats might also be used as a value-add to the customer, as well as for enabling communications and control. While the “jury is still out” to some degree on the cost-effectiveness and efficacy of these new strategies, PGE should evaluate options for engaging with this segment during the

procurement process.

3. **Small-size C&I customers (<200 kW peak load):** More than 40 percent of PGE's C&I load comes from C&I customers with less than 200 kW peak load (see Figure 2). While this segment has traditionally been challenging for C&I DR programs, it is worth exploring with vendors during the procurement process to understand options available for that segment. Expanding into this segment would require allowing customer nominations of less than 75 kW and may warrant a separate program or tariff structure. Vendors may approach this segment as an extension of the medium-size C&I market, with distributed low-cost communications and control technologies to 50-200 kW customers, or as a mass market program, which could be an extension of PGE's Nest thermostat program to small commercial.
4. **Site aggregation:** Use of existing interval meters and allowing the aggregation of multiple meters would enable more customers to participate and lower program equipment costs. In EnerNOC's view, site aggregation "is what is needed for PGE's program, if [PGE] could get it cost effectively." The ability to facilitate site aggregation will largely be dependent on the vendor's capabilities and requirements.
5. **Direct access customers:** Work with regulators to determine if and how program incentives could be appropriately allocated to non-PGE customers for participation in a C&I DR program.

3.2 Program Structure

The following section discusses recommendations for reframing the structure of PGE's C&I DR program, including program parameters like event timing and duration.

1. **Allow more flexibility across seasons and within seasons.** To maximize customer eligibility, PGE should allow differences in nominations within seasons and allow customers to participate in only one season.[7]
2. **Prioritize the hours and conditions that PGE expects to utilize the DR resource, and allow customer flexibility outside of those hours.** DR programs often fail when they try to cast too wide of a net. PGE should prioritize the top two to four most important hours needed for generation capacity deferral in each season as the required hours that a customer must be available to be eligible for the program. Enrollment for any hours outside of this window could be optional, based on the customer's operational needs. PGE could facilitate this by breaking the existing event windows up into more discrete windows (e.g., winter morning, winter evening, etc.) and providing a different value for each window. ERCOT's programs function similarly to this, with three seasonal program periods and multiple daily windows within each season that can be bid into separately —with a different price for each period.
3. **Facilitate partial credit for partial participation.** Under the current program structure, customers who can curtail for only a portion of the event window do not get payment, which discourages customers from participating in the event at all. PGE should explore ways to provide compensation to customers for partial participation, such as providing a reduced incentive of allowing customers to participate for just one hour at a time.
4. **Relax the notification time requirement for participation.** Given that PGE's primary objective for the C&I DR resource (i.e., generation capacity deferral) does not require 10 minute notification, Navigant recommends that PGE change the program requirements to a more traditional 2 or 4 hour notification. While EnerNOC currently operates the Energy Partner program with 2-4 hour notification in practice, lifting this requirement will help decrease program delivery costs by broadening the pool of eligible customers, decreasing automation needs, and reducing the amount of risk absorbed by the implementer.
5. **Emphasize automated curtailment, where possible, but continue to support both manual and automated curtailment.** Allowing both manual and automated curtailment reaches the broadest mix of customers, since some customers (e.g., with sensitive production

[7] Currently, differences in nominations are allowed across seasons, but not within seasons.

loads) will always prefer manual participation. However, facilitating automation for more customers (e.g., through financing, technology incentives for enablement, etc.) can help firm the resource and also allow certain customer segments to participate by curtailing remotely, as opposed to paying employees overtime to curtail after business hours. As an example, three of the seven non-participants with manual curtailment and four non-participants expressed possible interest in financing options from PGE for upgrading or installing a building management system (BMS) to enable automated curtailment.

6. **Revisit the baseline methodology used for some customers to avoid under- or over-estimating the baseline demand of customers with highly variable load.** PGE's current baseline method takes the highest 5 of 10 prior business days, with day-of adjustment except for winter mornings. For some customers with load that is highly variable (apart from weather-related variability), this can lead to a disconnect between demand reduction estimates and the actual DR actions. As an example, a customer with a large irregular industrial process load that was operating on the 5 highest of the 10 past business days, but not on the day of the DR event, would have a baseline that vastly over-estimates their true baseline demand the day of the event. This scenario can lead to challenges with program impact evaluation, less predictable program performance, and decreased participant satisfaction in the program outcomes. To account for this while still allowing customers with highly variable load to participate in a meaningful, more predictable way, PGE may consider offering certain customers one of the following options:
    a. Allow a customized baseline for customers with additional operational information that can help design a baseline methodology tailored to their specific operating characteristics. This is consistent with the evaluation findings of the Energy Partner program that a regression baseline could perform better for some customers.
    b. Allow certain participants to provide their own day-ahead baseline every day before the standard notification time, with penalties for large departures from the participant's "scheduled" load on non-event days.
    c. Require that these participants achieve a firm service level, rather than curtailing a certain amount (i.e., a "down-to" commitment as opposed to a "down by" commitment). PGE could do this through the existing Schedule 77 tariff or by providing a customer with a choice of baseline via the Energy Partner program. However, this approach provides PGE with less visibility into the probability that the load will be available for curtailment than the other options discussed above.[8]

3.3 Program Delivery

The following section discusses recommendations for changes to the program related to the program delivery, including marketing and outreach strategies.

1. **Identify one or more partner vendors that will provide technical expertise, implementation field staff, and ongoing customer support for a C&I DR program, while supporting PGE's objectives for a flexible customer-centric program in which PGE maintains the primary relationship with the customer.** Table 1 below shows recommended roles and responsibilities for the implementation vendor and PGE's existing DRMS vendor, relative to PGE. The agreement with the implementation vendor should consider the following:
    a. **Overall structure:** If PGE wants to manage the marketing and recruitment but needs more help on the technical side and back-end support, it can find the right type of vendor to provide such functions. More than likely, PGE should explore arrangements outside of a pay-for-performance structure to facilitate more program flexibility and

[8] *Measurement and Verification for Demand Response*, Prepared for the National Forum on the National Action Plan on Demand Response: Measurement and Verification Working Group, February 2013, https://eaei.lbl.gov/sites/all/files/napdr-measurement-and-verification.pdf.

ownership of the customer relationship. It is important to be clear about which party owns each function and which is in a supporting role to avoid competing efforts amongst parties.

b. **Agreement with the customer:** In the absence of a pay-for-performance structure with the vendor, then PGE can own the agreement with the customer, as opposed to the implementation vendor owning the agreement. To the extent possible, PGE should create a standard payment structure for all customers and the vendor to eliminate individual negotiations between the vendor and each customer.

c. **Marketing and recruitment:** If PGE has staff available that can open up prospective participants, the vendor could provide technical support to make prospects comfortable with participation in the program and help close the deal. In this scenario, a vendor would provide technical sales support, rather than pure customer sales resources, with PGE leading the marketing and recruitment. This would provide opportunities for PGE to have more contact with the customer and have more control over program-related branding.

d. Technology and enablement expertise:

i. A primary responsibility of the vendor would be to provide technical implementation support. The vendor would install and enable the equipment at the customer site, help the customer develop a curtailment strategy, and provide ongoing technical support to troubleshoot under-performance, refine the curtailment strategy, and potentially provide ongoing customer support via a call center (if desired by PGE).

ii. Vendors should be asked for solutions that can be implemented using customers' existing interval meters to reduce program costs. PGE should then carefully weigh the reduced costs proposed by the vendor against the reduction in the value of the data to the customer.

iii. Assuming PGE can use its existing DRMS for dispatch, there is no need to use an implementation vendor's DRMS.

e. **Exit strategy:** Ensure that expectations are clearly laid out for who owns the DR equipment at the end of the contract term, with a buyout clause specified, if the vendor owns the equipment over the course of the program.

Table 1. Roles and Responsibilities for C&I DR Program

Business Function	Responsible Party: PGE	Responsible Party: Implementation Vendor	Responsible Party: DRMS Vendor
a. Define Program Parameters	P, A	-	-
b. Marketing, Customer Recruitment and Outreach	P, A	p	-
c. Contract with Customer	P, A	-	-
d. Provision of Metering	P, A	-	-
e. Provision of Technology Products and Services	-	P, A	-
f. Technology Installation and Enablement	p	P, A	-
g. Initiate Load Control Events	P, A	-	p
h. Data Support and Performance Analysis	p	P, A	p
i. Billing and Settlement	A	P	p
j. EM&V[9]	P, A	-	p
k. Customer Service and Satisfaction	p, A	P	-
l. Coordination with Energy Trust, KCMs, and Other PGE Programs	P, A	p	-

Level of Responsibility:
A = Accountable (answerable for the correct and thorough completion of the deliverable or task, and often the one who delegates the work to the performer)
P = Perform (carries out the activity)
p = Performs with a lower level of responsibility than P
Blanks indicate that the party is neither accountable nor responsible.

2. **Focus the program marketing and delivery around the benefits to the customers:**
    a. **Highlight the corporate social responsibility benefits of participating in program marketing.** PGE should also investigate channels for externally showcasing current participants, such as through case studies or co-advertising with one of the customers to feature that customer through the program promotion.
    b. **Revisit the financial incentives that can be cost-effectively provided to customers**, including the level of financial support or financing that can be offered for automation. Demand response participation requires indirect costs on the part of the customer, including transaction costs and the value of service lost. To a customer considering participating in the program, the value provided by the program must

[9] Note that PGE is responsible/accountable for hiring an independent third-party to perform the EM&V.

outweigh these costs. While financial incentives are not the only benefit that customers consider, they generally must compensate for all or most of the indirect costs of participation (e.g., curtailing production, paying overtime for after-hours curtailment, installing new systems, etc.). Several non-participants indicated that the current program value does not perceptibly meet that threshold for their business.

c. **Enhance the real-time energy information system and promote its value to customers.** Customers are most interested in using the real-time energy information system to understand how they performed during events and to identify non-essential uses of energy within their facility. PGE could enhance the value to the customer by including case studies or workshops to show how customers can use the granular data for diagnostics.

   Current participants use the energy information system to varying degrees, with one of the key barriers to using more frequently is having limited time available to review the information. To the extent practicable, PGE should work with the vendor to ensure the system provides streamlined access to energy data and ease of use. Two customers also expressed interest in having "more real-time feedback on financial benefits" by seeing the incentives from events sooner after the event through the program portal.

d. **Package DR marketing and participation with other EE incentives**, including the SEM, Energy Tracker, and Energy Expert programs. This provides customers with more up-side to offset the effort and hassle factor of participating.

3. **Enhance education for both participants and non-participants:**

   e. **Non-participants:** PGE should emphasize clear, upfront communications to non-participants about the benefits of the program and the perceived costs, particularly in terms of how the program might affect their operations. Several non-participants expressed concern about impacts to occupancy comfort, which in many cases is something that can be overcome through customer education and an appropriate curtailment strategy. When current participants were asked what PGE might do to reduce barriers to participation for non-participants, several participants thought that information from current participants explaining how participation has impacted their business would help encourage more customers to participate. PGE could highlight the existing customer case studies on the Energy Partner website in initial discussions with non-participants and potentially identify current participants who can champion the program to other customers.

   f. **Participants:** One customer suggested organizing a forum for ongoing participants to interact and discuss ideas for curtailment strategies and lessons learned. Alternatively, PGE could host periodic webinars where customers could share best practices and lessons learned. A couple of customers also expressed interest in receiving help educating stakeholders within their organization about the benefits of the program and explaining why comfort or production might be temporarily impacted.

4. **Pursue opportunities for collaborating with the SEM program that minimize customer barriers and integrate into the Energy Trust's day-to-day processes with minimal overhead:**

   g. **Streamlined processes:** Given competing priorities for Energy Trust staff's limited time, PGE should strive to streamline the efforts required by Energy Trust program managers and contractors for cross-marketing.

   h. **Coordinated customer touchpoints:** This program needs to be sensitive to customer fatigue by coordinating touchpoints to the extent possible, since some customers may have already been contacted about the Energy Partner program by EnerNOC or their KCM, in addition to the Energy Trust contractor, who does the cross-marketing to the customer.

   i. **Consistent contractor touchpoints:** Energy Trust contractors are currently blending in discussion of the Energy Partner program, where appropriate, and if customers have questions. PGE should build in consistent touchpoints (e.g., quarterly) to ensure that cross-marketing the Energy Partner program continues to be a priority for the Energy Trust's contractors.

j. **Training curriculum:** The Energy Trust suggested incorporating DR into the SEM curriculum, with an emphasis on "what is DR," what makes good DR opportunities, and how it relates to demand management. This approach would help promote DR, but would also help enhance the value proposition to the customer for participation in SEM. While this approach would market more broadly than the targeted approach PGE has used previously, it shifts the focus away from providing customers a particular "product," while opening the door for conversations about Energy Partner and serving as a foundation for expanding the program reach beyond customer segments historically targeted.

k. **Technical alignment:** At a high level, there is overlap in the use of energy information and interval metering between the Energy Partner and SEM programs. However, EnerNOC required a separate energy information management system and meter that did not match the needs of the SEM program, particularly for industrial customers with unique production data. While it may ultimately be infeasible to find a system in the near-term that serves the needs of both programs and is supported by DR providers, PGE should explore this as an option with vendors during the procurement process.

l. **Formal agreement:** Explore options for codifying the terms of collaboration with the Energy Trust in a formal agreement that clearly defines expectations for the arrangement, including opportunities for PGE to cross-market the SEM program. PGE should also clearly state expectations with DR vendors upfront for coordination with the SEM program as part of the procurement process.

5. **Increase marketing to medium-size customers (200 kW to 1+ MW peak load).** Partner with a vendor that is geared toward smaller C&I customers, particularly in the commercial sector.

6. **Evaluate options for using existing interval meters to lower program equipment costs.** If metering is part of a vendor's proposed solution, PGE should ask the vendor for program cost estimates with and without the use of additional meters, as well as any technical limitations or interoperability issues that the vendor might anticipate with using PGE's interval meters. PGE should then evaluate the cost savings against the tradeoffs in more detail.

7. **To avoid fall-off of customer load curtailment, set initial load curtailment targets low and educate customers more fully on how DR may affect their operations.** By setting initial load curtailment targets low, the customer can start to understand how DR will affect their operations and will start off successful in the program. PGE used this approach with a current participant and saw positive results. The implementation vendor should also discuss different possible operations scenarios in depth with the customer while developing the curtailment strategy to ensure customers can provide accurate estimates of curtailment across varying operational conditions.

8. **Leverage existing and new channels for broader and more continuous customer engagement:**

    a. **KCMs:** PGE should continue to use and grow the role of KCM's as one of the channels for marketing and customer enrollment. If PGE decides to lead marketing and recruitment in-house, the role of KCMs will be particularly important. Opportunities include more clearly defining the expectations for KCM contributions to enrollment in relation to the implementation vendor and providing more training for KCMs specific to the program. Collaboration with account managers in other jurisdictions tends to be most successful when the utility ties program-specific metrics to performance scores, if that option is available to PGE.

    b. **Local technical expertise:** Several participants said that they would have benefited from more upfront implementation assistance with deep technical knowledge of certain end uses. Customers also expressed a desire for ongoing technical assistance throughout their participation for identifying new ways to curtail more. PGE may consider partnering with a local energy engineering firm, such as Cascade Engineering, to provide strategic technical expertise for some customers.

c. **Alternative marketing channels:** Exploration of new marketing channels will be particularly crucial if PGE markets the program in-house. Examples could include offering referral bonuses to building controls trade ally channels for large commercial (i.e., similar to Hawaiian Electric Company), cross-marketing with the vendor who provides PGE's storage solutions, or working through local industry associations and chambers of commerce.

3.4 Procurement

Given PGE's unique market and operating environment, rather than offer a traditional RFP solicitation, Navigant recommends that PGE define the situation and the problem, and invite solutions in a very short response format (e.g., with only proposed structures, drivers of pricing, caveats, and indicative pricing). Based on the vendor's responses, PGE would then invite a few firms for a brainstorming discussion that helps PGE think through the issues constructively. Following this working session, PGE would select one of the firms to help modify the program and to deliver it in a new way that addresses the challenges identified.

Section IV Summary

PGE has faced challenges building C&I DR capacity within its service area, due to issues like limited industrial load, the need for a dual peaking resource, and limitations on participation from emergency generation and direct access customers. However, there are changes PGE can make to increase participation and capacity by refocusing the program as a customer-centric resource comprised of more diverse C&I customers in terms of size and industry type, with an emphasis on education and strategic partnerships for customer outreach. As part of this, PGE should also revisit and prioritize the operational requirements for the C&I DR resource to facilitate flexibility for the customer where possible, while also meeting PGE's operational needs. This new DR philosophy emphasizes flexibility within the program design, enhanced customer engagement, and an enhanced value proposition for the customer to facilitate greater participation from customers within the customers' and PGE's operations requirements.

Appendix 10. Rush Hour Rewards Findings Summary

MEMORANDUM

To: Josh Keeling and Alex Reedin, Portland General Electric

Cc: Dyon Martin and Roch Naleway, Portland General Electric

From: Scott Reeves and Jim Stewart, Cadmus

Subject: PGE Rush Hour Rewards Findings Summary

Date: December 27, 2016

This memo presents the methodology and findings from Cadmus' evaluation of Portland General Electric's (PGE) smart thermostat pilot program—Rush Hour Rewards (RHR)—for winter 2015/2016 and summer 2016.

Findings Overview

The evaluation produced several key findings regarding the first two seasons:

- ***Program Delivery/Enrollment***. In October 2015, PGE's RHR pilot launched on schedule, quickly surpassing its enrollment targets of 300 heating and 700 cooling participants for 2016. As of September 2016, the program had enrolled 398 heating and 2,492 cooling customers.
- ***Program Impacts***. The RHR pilot achieved significant demand reductions per customer during RHR events. Load reductions averaged between 0.4 and 0.6 kW per customer during winter events and about 0.8 kW per customer during summer events.
- ***Customer Experience***. Winter and summer participants reported high satisfaction levels with a variety of RHR outcomes, including comfort during events, Nest thermostats, participation incentives, and with the program overall. Customers reported higher satisfaction levels after participation.

Recommendations

Based on evaluation of program performance during the first two pilot seasons, Cadmus offers the following recommendations for consideration:

- RHR impacts on customer peak demand and satisfaction support the continuation and possible expansion of the RHR program. Cadmus did not estimate the cost-effectiveness of the RHR program, but the estimates of demand savings per customer were large and in line with PGE's

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expectations. PGE reported that for a range of assumptions about measure life, the RHR program would prove cost-effective.[1]

- PGE should continue to evaluate the RHR program for a second year, including both summer and winter seasons. PGE could refine its first-year assessment of demand response capacity benefits and cost-effectiveness and identify additional opportunities for improving the program implementation.
- PGE should expand the program to include customers with electric furnaces. Expanding eligibility for the program would provide PGE with additional demand response capacity.
- PGE should expand the program to include customers with other brands of connected thermostats. Expanding eligibility for the program would provide PGE with additional demand response capacity.
- PGE should make improvements to its meter data management system and customer information system to increase its participation tracking and meter data storage and processing capabilities.
- PGE should work with the Energy Trust of Oregon to explore opportunities for achieving energy efficiency savings occurring through this program. Integrating efficiency and peak demand savings may increase the cost-effectiveness of smart thermostat programs and allow the programs to reach low and moderate income customers.

Program Description

In October 2015, PGE launched a smart thermostat pilot program for residential customers who installed a Nest learning thermostat. Nest, the thermostat manufacturer and demand response service provider, markets the program and manages the branded RHR portal for PGE. This portal allows PGE to manage loads during RHR events by adjusting temperature setpoints on participants' Nest thermostats. This primary objective of this pilot evaluation was to measure demand reduction during summer and winter RHR events. Although Nest thermostats may provide energy efficiency savings that occur on peak, this study did not measure these savings.

Outreach and Eligibility

Nest markets the program to residential customers with Nest-brand learning thermostats. Because Nest can communicate with its customers through the thermostat and Nest software, Nest primarily delivers marketing of PGE's RHR program through monthly/seasonal notifications to owners or to those newly purchasing and installing Nest thermostats. Nest thermostats assist in targeting eligible customers by

[1] The cost-effectiveness of RHR depends on retaining participants for long enough to obtain sufficient demand response capacity benefits to cover the programs initial fixed costs, which include one-time incentive payments to customers, PGE investments in computer hardware and software, and set-up fees to program implementers. As smart thermsotat programs are relatively new offerings, there is not much industry data on customer retention.

collecting data about connected HVAC equipment and about customers' heating and cooling profiles, which can be used to identify homes that employ qualifying equipment.

PGE provides significant marketing support for the the program through several mediums, including PGE's program webpage, targeted emails to PGE customers on hot summer days, bill inserts, and social media. PGE's marketing and communication channels generated more than 40% of the traffic to Nest's PGE-specific RHR registration page.

Participants may enroll for the summer season, winter season, or both, depending on their qualifying equipment. Summertime participants must have electric central air conditioning or heat pumps; wintertime participants must have electric forced-air furnaces or heat pumps, although the program primarily enrolled heat pump customers during the first winter season. Nest cannot currently identify electric forced-air furnace customers based on how the Nest thermostat is wired. Verification of an electric forced air furnace requires analysis of the customer's energy use.

Customer Incentives

PGE customers received an incentive of $25 upon enrollment, with additional incentives of $25 per winter/summer season, depending on whether their heating or cooling equipment qualifies. Participants with heat pumps could receive up to $50 per year, while customers with central air conditioning or central electric furnaces receive $25 per year. Customers must participate in at least 50% of RHR events per season to qualify for the seasonal incentive payments.

To verify customers meet criteria to receive incentives, Nest currently provides PGE with a list of active customers and program enrollment dates. PGE then uses these data and the number of overlapping events to calculate incentive payments. Additionally, Nest supplied PGE with a list of customers whose thermostats did not maintain an Internet connection for the event season. Going forward, a more robust verification of customer participation is under development, including a customer retention process to lure customers back into participation as well as an unenrollment process for customers who choose not to participate.

Event Delivery

Once a customer enrolled in RHR, Nest notified the customer of upcoming "Rush Hours" (i.e., demand response events) and of events in progress. Notifications arrived through the Nest app and through an icon that appeared on the thermostat's display. PGE decided when to call events, which were activated using the utility's interface with the Nest RHR platform.

Afternoon events required PGE to notify intent to dispatch the event by 10:00 a.m. on the same day. All morning events required PGE to send dispatch notices by 7:00 p.m. of the previous day. Customers that tried to control their thermostats in a way contrary to the desired response (e.g., setting a lower temperature during a summer event) received a "speedbump" notification, reminding them that an electricity "Rush Hour" was in effect, and asking them to confirm that they wanted to change their setpoints (though this did not prevent them from doing so).

Nest algorithms determined the specific load control response of each customer's thermostat, based on the household's usage profile (as recorded by the Nest thermostat). If the algorithm deemed it efficient, the thermostat preconditioned the home for up to an hour in advance of an event. Note that preconditioning was not efficient for homes with usage profiles indicating a high thermal loss rate.

The Public Utility Commission of Oregon requires PGE to call a minimum of six events per season (though PGE may call up to 10 events), with events scheduled to last three consecutive hours and occurring on weekday (non-holiday) afternoons, when seasonal weather increases peak demand (i.e., on cold days during winter and warm days during summer).

Event Schedule

Table 1 shows the event days, times, and average temperatures for the summer and winter seasons.

Table 1. RHR Seasonal Event Dates and Times*

Event	Winter			Summer		
	Date	Hours	Avg. Event Temp.	Date	Hours	Avg. Event Temp.
1	Dec 29	4:00 p.m. - 7:00 p.m.	38	Jul 27	4:00 p.m. - 7:00 p.m.	86
2	Dec 30	4:00 p.m. - 7:00 p.m.	36	Jul 29	4:00 p.m. - 7:00 p.m.	89
3	Jan 4	4:00 p.m. - 7:00 p.m.	34	Aug 4	4:00 p.m. - 7:00 p.m.	87
4	Jan 6	4:00 p.m. - 7:00 p.m.	39	Aug 11	4:00 p.m. - 7:00 p.m.	87
5	Feb 1	4:00 p.m. - 7:00 p.m.	44	Aug 12	4:00 p.m. - 7:00 p.m.	93
6	Feb 9	7:00 a.m. - 10:00 a.m.	45	Aug 18	4:00 p.m. - 7:00 p.m.	94
7	Feb 17	5:00 p.m. - 8:00 p.m.	50	Aug 19	4:00 p.m. - 7:00 p.m.	95
8	Feb 26	5:00 p.m. - 8:00 p.m.	50	Aug 25	4:00 p.m. - 7:00 p.m.	90
9				Aug 26	3:00 p.m. - 6:00 p.m.	94

*This analysis excludes one early summer season event (June 6, 2016) given that participating customers not yet been assigned to treatment or control groups at the time.

Research Objectives

PGE outlined the following objectives related to pilot delivery and evaluation research:

- Implement the program over five seasons (i.e., winter 2016, summer 2016, winter 2017, summer 2017, winter 2018), with six to 10 events per season
- Measure the impact of events on customers' comfort and satisfaction
- Measure the demand reduction capacity, any preconditioning or rebound effects, and cost-effectiveness
- Determine the best strategies for scaling the pilot program into a mass market program
- Achieve positive customer experiences

This memo focuses on reporting load impacts and findings, drawn from customer surveys from the first winter and summer seasons. Although smart thermostats may provide energy savings, this pilot evaluation did not seek to measure energy savings.

Methodology

Research Design

To estimate thermostat controls' impacts, Cadmus worked with PGE to implement the pilot as a randomized control trial (RCT).[2] The RCT involved randomly assigning program participants (i.e., residential customers with Nest thermostats meeting eligibility requirements) to a treatment group or a control group. Treatment group customers experienced RHR load control events, while control group customers did not. An RCT, serving as the gold standard in program evaluation, was expected to produce an unbiased estimate of the pilot's impacts on energy demand.

Cadmus randomly assigned program participants to the treatment or control group, and then conducted tests to verify that the randomized treatment and control groups had statistically equivalent pretreatment consumption.

Data Sources

Cadmus used the following data sources in performing the analysis:

- ***Participant enrollment data***, provided by PGE, tracked enrollment for treatment group and control group customers. These data included participant name, contact information (e.g., address), a unique customer identifier (i.e., point of delivery [POD] ID), and an enrollment date.
- ***Interval consumption data***, provided by PGE for all enrolled participants. For post-enrollment periods, these included watt-hour electricity consumption at 15-minute-intervals, measured useing advanced metering infrastructure (AMI) meters. For historical usage periods (prior to enrollment), only hourly data were available. The pre-enrollment data recorded customer kWh consumption (Watt hours truncated at the thousands place) from December 2014 through September 2016.
- ***Local weather data***, including hourly average temperatures from December 2014 through September 2016 for seven National Oceanic and Atmospheric Administration weather stations. The team used zip codes to identify weather stations nearest each participant's home, and merged the weather data with the participant's billing data.

Customer Enrollment and Random Assignment

Since PGE's launch of RHR, customers have continuously enrolled in the pilot. Initially, PGE targeted enrollment of 300 winter-season participants (with heat pumps or electric heat) and 700 summer-season participants (using heat pumps or central air conditioning). By the summer season's end, the program had enrolled 398 winter participants and 2,492 summer participants.

At the beginning of each season, Cadmus randomly assigned all program participants to the treatment group or control group, and then used pretreatment monthly consumption data and post-treatment

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[2] This design followed recommendations by the *U.S. Department of Energy's Uniform Method Project Behavior-Based Program Evaluation Protocols* and EPRI's *Consumer Behavior Study Evaluation Guidelines*.

consumption data on non-event days to verify that the changes did not result in statistically significant electric consumption differences between the randomized treatment and control groups. Customers signing up after initial random assignments were randomly assigned on a rolling basis to the treatment or the control group.[3]

Savings Estimation

Cadmus performed a difference-in-differences panel regression analysis of the hourly energy consumption of treatment and control group customers to estimate the RHR load impacts. The analysis compared the average consumption change between event and non-event hours for treatment group customers, with the average consumption change between event and non-event hours for control group customers. Cadmus estimated the impacts in the two hours before, three hours during, and eight hours after each event. The regression included independent variables for customer pre-treatment consumption, customer demand for heating or cooling (i.e., heating degree hours or cooling degree hours), the hour of the day, and the day of the week. The regression analysis will likely result in an unbiased estimate of load control impacts due to random assignment of customers to treatment. This memo’s appendix presents the specific model used to estimate these impacts.

Participant Surveys

Cadmus administered several surveys to assess customers’ experiences. These included the following:

- A baseline survey to assess customer recruitment (fielded during enrollment);
- An event survey to assess customer awareness, thermal comfort, and behaviors during RHR events
- An end-of-season survey design to assess overall program experience.

These surveys asked customers about their satisfaction with the program, their perceptions about marketing effectiveness, their motivations for and barriers to participating, awareness of demand response and RHR events, and energy-use attitudes and behaviors about space heating and cooling. The surveys also included a battery of demographic questions.

Analysis Sample

Data Screening

Starting with a census treatment and control group participants, Cadmus excluded the following customers from the analysis sample:

- Customers who could not be matched to AMI data
- Net-metering customers

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3 Using a power analysis, Cadmus determined the appropriate sample sizes to detect the program’s impact. As enrollment increases, Cadmus will reassess these thresholds prior to making seasonal reassignments and allocations of the minimum control group sizes required to detect the expected impacts.

- Customers without consumption data reported to watt-hours (i.e., kWh to three decimal places) during the treatment period[4]

Table 2. Sample Disposition—Winter

Screen	Treatment		Control		Overall	
	Accounts Remaining	Percent Remaining	Accounts Remaining	Percent Remaining	Accounts Remaining	Percent Remaining
Original PODIDs*	104	100%	131	100%	235	100%
Matched to Consumption Data	104	100%	131	100%	235	100%
Net Metering Customers	104	100%	131	100%	235	100%
Insufficient kW data (e.g., integer values)**	85	82%	107	82%	193	82%
Final Analysis Group	**85**	**82%**	**107**	**82%**	**193**	**82%**

*Original PODIDs reflect total enrolled customers participating in at least one seasonal event.

**Given continuous program enrollment and event-specific attrition (due to insufficient meter data during specific event hours), the number of customers with valid data varied between event hours. This value represented the maximum, where event-specific attrition ranged from 22 to 30 customers for the treatment group and from 28 to 40 customers for the control group.

Table 3. Sample Disposition—Summer

Screen	Treatment		Control		Overall	
	Accounts Remaining	Percent Remaining	Accounts Remaining	Percent Remaining	Accounts Remaining	Percent Remaining
Original PODIDs*	1,577	100%	915	100%	2,492	100%
Matched to Consumption Data	1,559	99%	901	98%	2,460	99%
Net Metering Customers	1,549	98%	892	97%	2,441	98%
Missing 2015 data	1,519	96%	857	94%	2,376	95%
Insufficient kW data (e.g., integer values)**	1,436	91%	790	86%	2,226	89%
Final Analysis Group	**1,436**	**91%**	**790**	**86%**	**2,226**	**89%**

*Original PODIDs reflect total enrolled customers participating in at least one seasonal event.

**Given continuous program enrollment and event-specific attrition (occurring due to insufficient meter data during specific event hours), the number of customers with valid data varied between event hours. This value represented the maximum, while event-specific attrition ranged from 121 to 162 customers for the treatment group and 87 to 128 customers for the control group.

Figure 1 and Figure 2 compare average hourly consumption for treatment and control group customers on non-holiday, non-event weekday hours during each season. Cadmus did not find statistically

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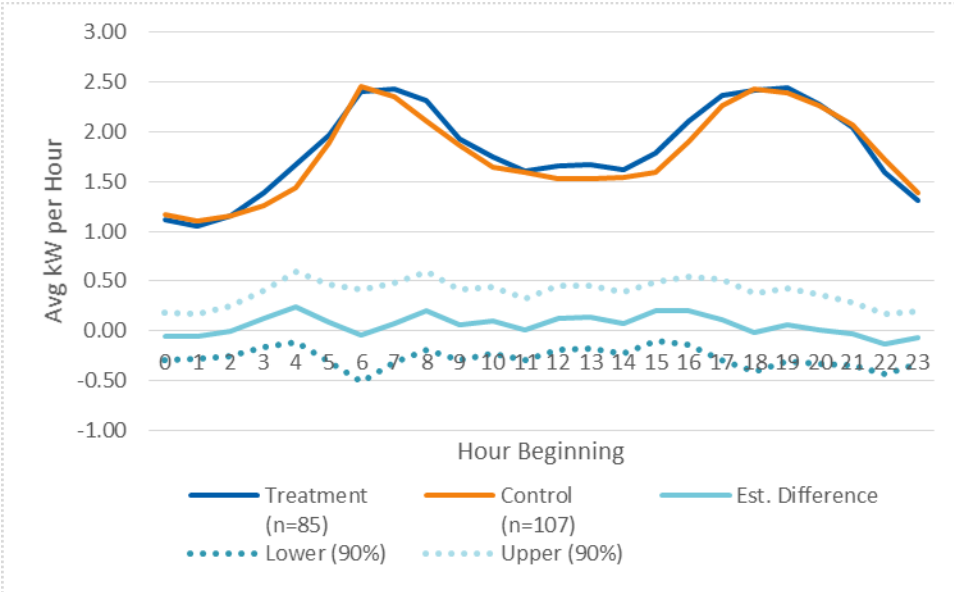
[4] Prior to program enrollment, customer meters recorded kW-hour interval consumption at integer values. Upon program enrollment, PGE attempted to switch customer meters to record watt-hour interval consumption to three decimal places. Due to communication problems, however, not all customer meters switched over.

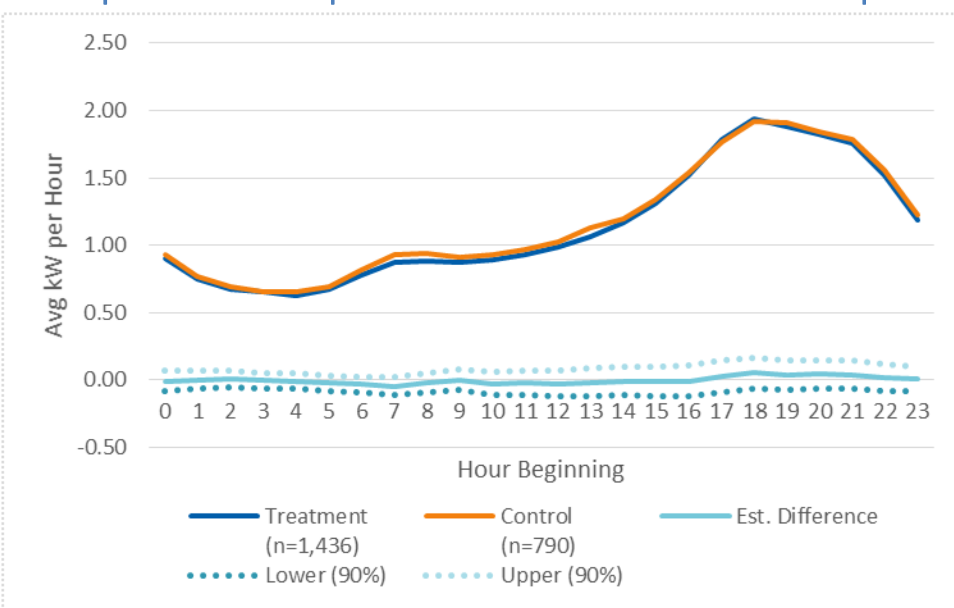
significant differences in consumption during any hours of the winter or summer seasons. This suggests that the randomization resulted in well-balanced treatment and control groups.

Figure 1. Comparison of Consumption Between Treatment and Control Groups—Winter*



Note: The figure shows average consumption per customer, per hour, on non-event, non-holiday weekday hours for randomly assigned treatment and control groups.

Figure 2. Comparison of Consumption between Treatment and Control Groups—Summer*



Note: The figure shows average consumption per customer, per hour, on non-event, non-holiday weekday hours for randomly assigned treatment and control groups.

Impact Findings

Figure 3 and Figure 4 show estimates of average load impacts per hour, per treatment group customer for winter and summer RHR events. The figures show average impact estimates by season (i.e., winter and summer) and event start times due as estimated baselines and load impacts depend on the hour-of-day.

Figure 3. Average Winter Season Impacts, by Event Start Time

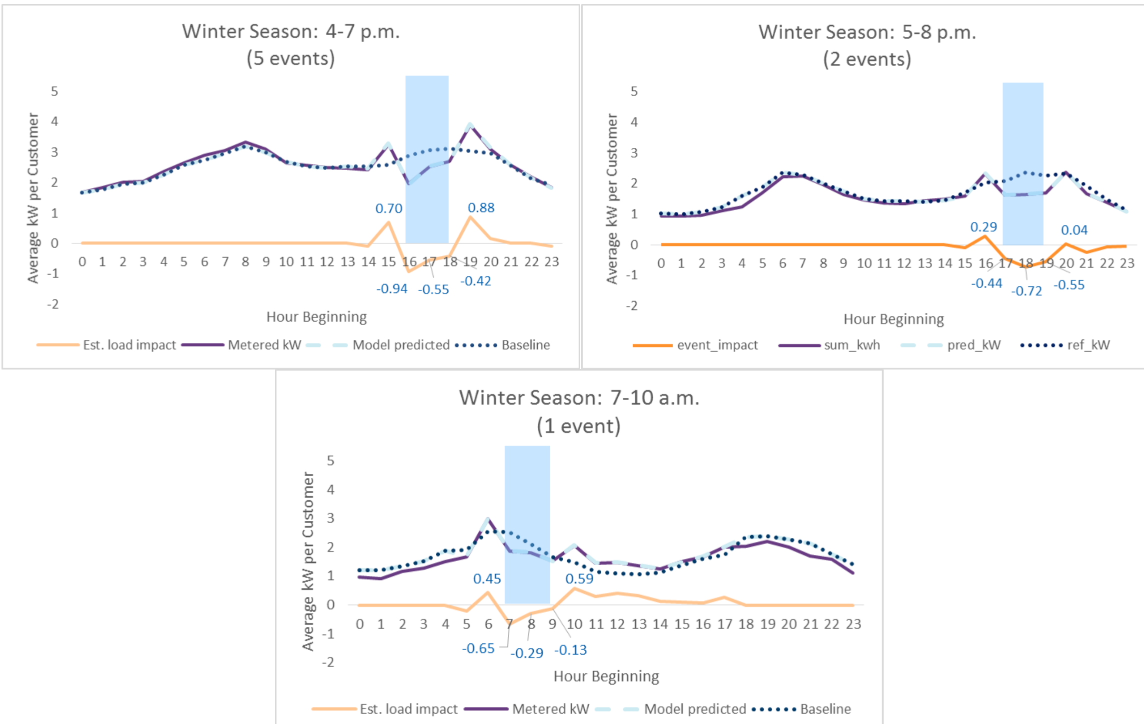
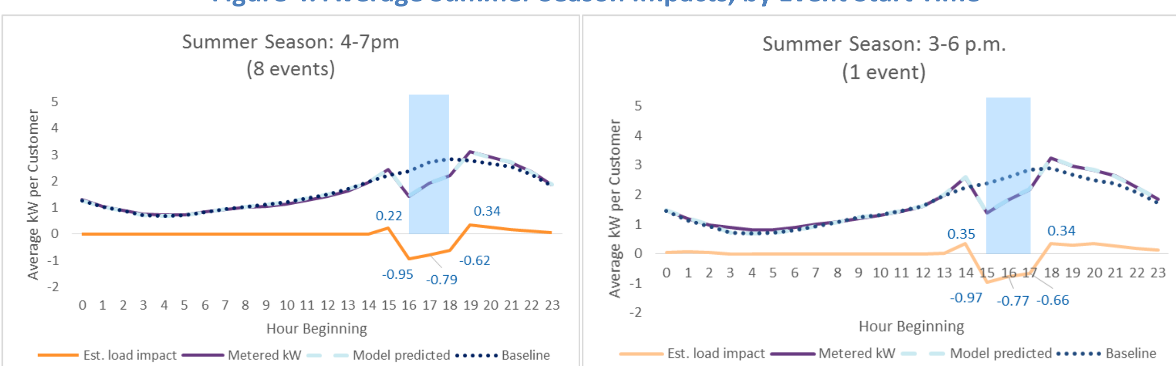


Figure 4. Average Summer Season Impacts, by Event Start Time



During winter, events started at 7:00 a.m., 4:00 p.m., or 5:00 p.m. During summer, events started at 3:00 p.m. or 4:00 p.m. This document's appendix reports estimates of average load impacts per customer for each hour of each event.

Table 4 provides estimated impacts in a table.

Table 4. PGE RHR Impact Summary, by Season and Event Starting Time*

Event Hour	Winter (kW per customer)			Summer (kW per customer)	
	4:00 p.m. - 7:00 p.m. (5 events)	5:00 p.m. - 8:00 p.m. (2 events)	7:00 a.m. - 10:00 a.m. (1 event)	4:00 p.m. – 7:00 p.m. (8 events)	3:00 p.m. – 6:00 p.m. (1 event)
Pre Hour 1	0.70	0.29	0.45	0.22	0.35
Event Hour 1	***-0.94***	***-0.44***	***-0.65***	***-0.95***	***-0.97***
Event Hour 2	***-0.55***	***-0.72***	***-0.29***	***-0.79***	***-0.77***
Event Hour 3	***-0.42***	***-0.55***	***-0.13***	***-0.62***	***-0.66***
Post Hour 1	0.88	0.04	0.59	0.34	0.34
Post Hour 2	0.16	-0.26	0.29	0.25	0.29
Post Hour 3	0.01	-0.07	0.40	0.18	0.33
Post Hour 4	0.01	-0.04	0.31	0.10	0.26
Avg. kW Reduction	**-0.64**	**-0.57**	**-0.36**	**-0.79**	**-0.80**
Avg. kWh Reduction**	**-0.15**	**-1.75**	**0.97**	**-1.27**	**-0.83**
Min kW	**-0.42**	**-0.44**	**-0.13**	**-0.62**	**-0.66**
Max kW	**-0.94**	**-0.72**	**-0.65**	**-0.95**	**-0.97**

*All winter and summer event hour impacts were significant at the 5% level, except for hours 2 and 3 for the 7:00–10:00 a.m. event.

**These estimates represent the average energy impact per customer, per event, including the hour immediately preceding the first event hour and the four hours immediately following the last event hour.

The RHR program achieved large demand reductions during summer and winter events. Depending on event start times, load reductions averaged from 0.4 kW and 0.6 kW per customer in winter. Load reductions averaged about 0.8 kW per customer in summer. Based on the participation in each event and the estimates of kWh savings per customer per event, the program achieved total kWh savings of 16,999 kWh for summer and 305 kWh for winter.

Typically, the first event hour yielded the largest demand reductions. During winter, the load reduction during the first event hour averaged between 0.4 kW and 0.9 kW per customer. During summer, the first-hour load reduction per customer averaged about 1 kW per customer. Only winter events initiated at 5:00 p.m. achieved higher average load reductions during the second event hour (0.7 kW per customer) than the first event hour (0.4 kW per customer). For all other event starting times, load impacts decreased during the second and third event hours. Estimated load impacts were 33% to 50% lower in the second event hour and 33% to 80% lower in the third event hour.[5]

As expected, RHR pre-cooling or pre-heating during the hour immediately preceding the first event hour increased consumption above baseline. During winter, pre-heating increased average demand per customer between 0.3 and 0.7 kW. During summer, pre-cooling raised average demand per customer between 0.2 and 0.4 kW.

Consumption rebounded when events ended, given heating or air conditioning units operated to return the homes to their programmed temperature setpoints. During winter, rebound increased average demand per customer between 0.6 kW and 0.8 kW during the first hour. During summer, rebound increased average demand by about 0.3 kW. In general, rebound lasted one or two hours.

Table 5 presents the estimated impacts as a percentage of baseline demand.

Table 5. PGE RHR Impact Summary—Percent Reduction, by Season and Event

Event Hour	Winter			Summer	
	4:00 p.m.- 7:00 p.m. (5 events)	5:00 p.m. - 8:00 p.m. (2 events)	7:00 a.m. - 10:00 a.m. (1 event)	4:00 p.m.- 7:00 p.m. (8 events)	3:00 p.m. - 6:00 p.m. (1 event)
Pre Hour 1	27%	14%	17%	10%	15%
Event Hour 1	***-33%***	***-21%***	***-26%***	***-40%***	***-41%***
Event Hour 2	***-18%***	***-30%***	***-14%***	***-29%***	***-30%***
Event Hour 3	***-13%***	***-24%***	***-8%***	***-22%***	***-23%***
Post Hour 1	29%	2%	39%	12%	12%
Post Hour 2	5%	-13%	25%	10%	11%
Post Hour 3	0%	-4%	36%	7%	13%
Post Hour 4	1%	-3%	29%	5%	11%
Avg. Event % Reduction	**-21%**	**-25%**	**-16%**	**-30%**	**-31%**

During winter, the RHR pilot reduced average demand by 20%–33% during the first event hour, 15%–30% during the second event hour, and about 10%–25% during the third event hour. During summer, the pilot reduced demand by about 40% during the first event hour, 30% during the second event hour, and 20% during the third event hour. Pre-cooling or pre-heating during the hour preceding

[5] This degradation likely reflected drift in home interior temperatures during events due to passive heat loss that caused space conditioning units to resume operation. For example, in summer during event hours, interior temperatures rise until reaching the RHR-adjusted thermostat setpoint. At that point, air conditioning units turn on again and run periodically to maintain the home interior at the adjusted temperature. In poorly insulated homes, interior home temperatures drift more quickly to the RHR-adjusted setpoint, and average load impact are lower. In more thermally resistant homes, interior temperatures drift more slowly, with greater average load impacts.

the first event hour increased demand by 10%–30%. After most events ended, demand rebounded 10%–40% above expected levels.

Planning Assumptions

Cadmus recommends that for resource planning purposes PGE should assume an average demand reduction of 0.7 kW per RHR customer at the meter for winter and 0.8 kW per RHR customer at the meter for summer.[6] This recommendation assumes:

- In winter, future events will be called on non-holiday weekdays between 4:00 p.m. and 7:00 p.m.
- In summer, future events will be called on non-holiday weekdays between 4:00 p.m. and 7:00 p.m.
- Outside temperatures during future RHR events will be similar to those experienced during RHR events in winter 2015/2016 and summer 2016.
- Future RHR program participants will have space heating and cooling equipment similar to that of participants in 2015 and 2016.
- Nest will implement the RHR program similarly in the future.

When applying these capacity assumptions, PGE should keep in mind the following:

- The recommended assumptions do not account for energy losses from transmission and distribution. Accounting for line losses of 7% would marginally increase the assumed impacts to 0.75 kW per RHR customer for winter and 0.85 kW per RHR customer for summer.
- The recommended assumptions represent the approximate average impact across the three hours of a RHR event. It is expected that the load reduction during the first hour will be largest and the load reduction during the third hour will be smallest. For example, in summer, PGE may achieve a load reduction greater than 0.8 kW per customer during the first hour and less than 0.8 kW during the third hour.

Cadmus recommends that PGE update its planning assumptions after evaluating the RHR program in winter 2016/2017 and summer 2017.

Customer Experience Findings

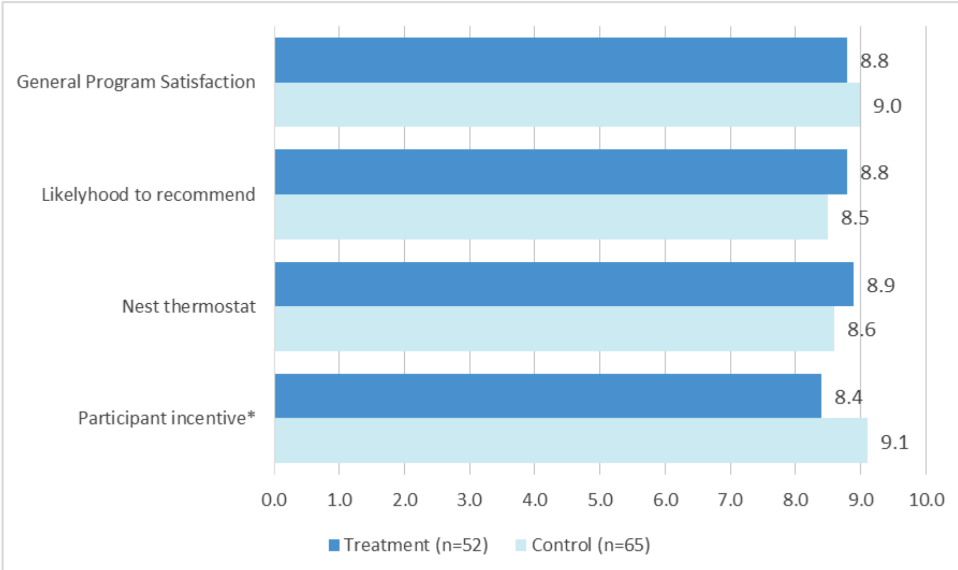
Throughout the pilot, survey response rates proved to be extremely high, with each survey yielding a 50% or higher response rate.

Customer Satisfaction

An important question concerns RHR's effect on customer satisfaction, regarding the program and PGE. Figure 5 and Figure 6 show customer satisfaction ratings for treatment and control groups .[7]

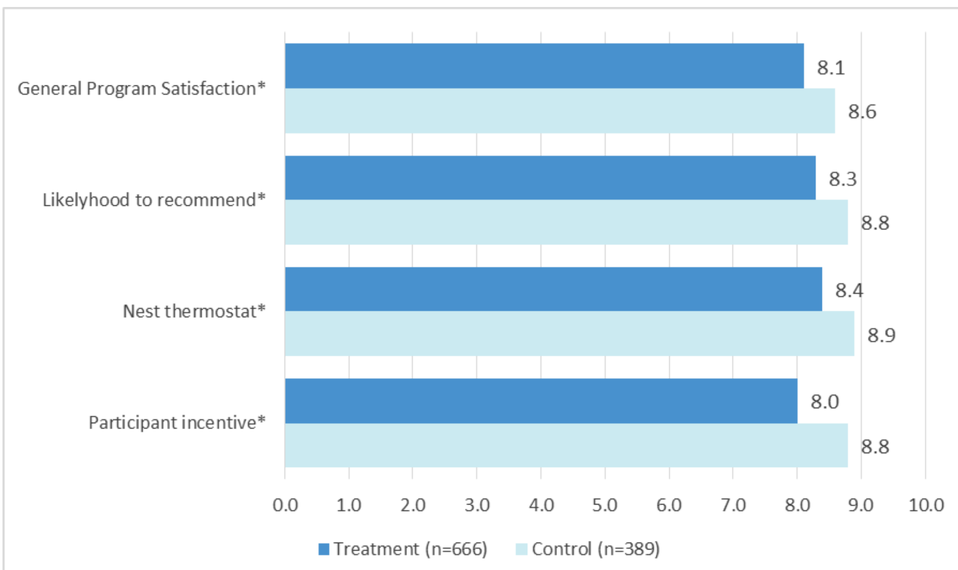
[6] These estimates are based on the average impacts during the 4 p.m. to 7 p.m. periods for both winter and summer seasons, as these were the most frequent event hours.

Figure 5. Winter Post-Season Program Satisfaction and Likelihood to Recommend



*Statistically significant difference between treatment and control groups with 90% confidence.

Figure 6. Summer Post-Season Program Satisfaction and Likelihood to Recommend



*Statistically significant difference between treatment and control groups with 90% confidence.

RHR participants rated the program very positively. In winter and summer, the RHR program, Nest thermostat, and incentives received high average ratings of 8 or greater on a 10-point scale from treatment and control group customers.

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[7] The recruitment surveys did not include these ratings because, at that time, participants had neither yet received program treatment assignments nor experienced program activity.

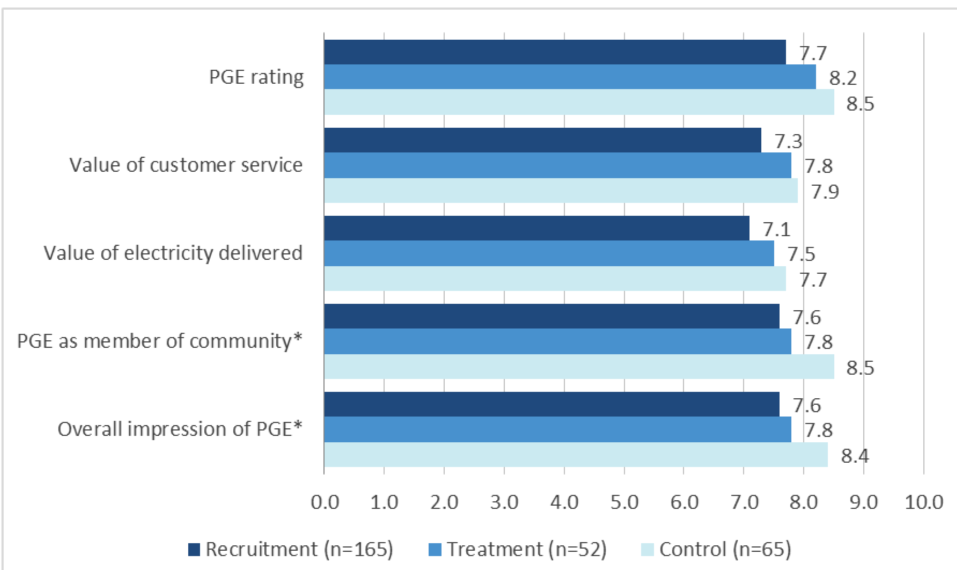
In winter, a clear pattern did not emerge for customer satisfaction between treatment and control group customers. Treatment group customers were more likely to recommend the program and to rate the Nest thermostat higher, but the only statistically significant difference was with satisfaction with the program incentive.

In summer, control group customers rated the program more highly in each category than treatment group customers. All differences were statistically significant. The control group awarded ratings about 0.5 points higher than did the treatment group.

In both winter and summer, incentive payments prompted the greatest satisfaction difference between treatment and control groups. This substantial difference may reflect control customers receiving participation benefits (i.e., the incentives) without experiencing the costs (i.e., temporary loss of thermostat control).

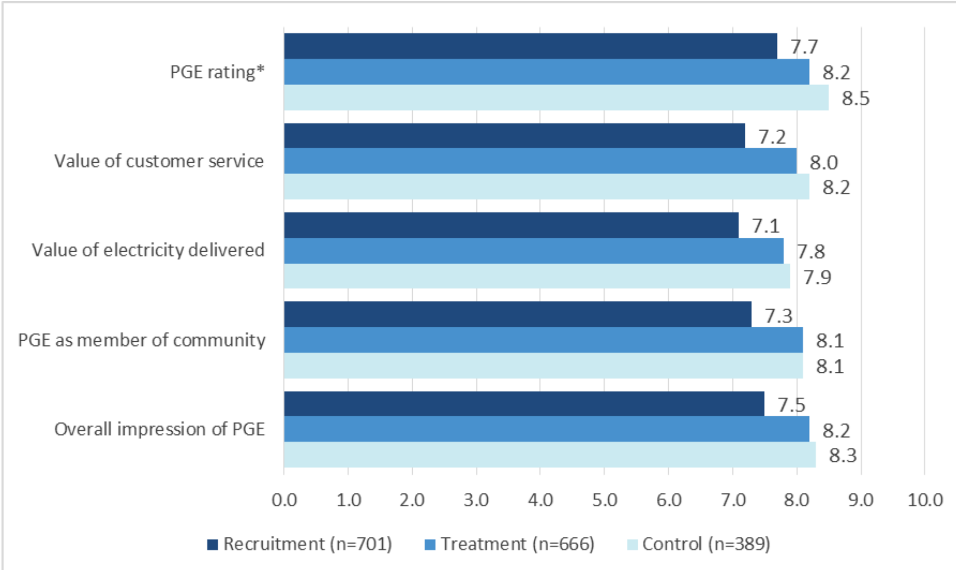
Figure 7 (winter participants) and Figure 8 (summer participants) show satisfaction with PGE ratings, beginning from the recruitment period (after enrollment but before events began) and after the event season. The figures shows separate post-season ratings for the treatment and control groups.

Figure 7. Winter Pre- and Post-Season Satisfaction with PGE



*Statistically significant difference between treatment and control groups with 90% confidence.

Figure 8. Summer Pre- and Post-Season Satisfaction with PGE



*Statistically significant difference between treatment and control groups with 90% confidence.

Customers gave PGE high satisfaction ratings. Though satisfaction became higher after participating, without surveys of nonparticipant customers, it is difficult to determine whether this increase represents a program effect or another time-varying factor.

In every category, the control group rated PGE at least as high as the treatment group. Many of the differences, however, were small and statistically insignificant, suggesting that participating in the treatment group did not significantly diminish satisfaction levels.

Awareness and Behavioral Response to Events

Figure 9 compares event awareness and behavioral responses of treatment group customers for the winter and summer seasons.[8] Awareness of RHR events achieved almost 90% for both summer and winter. Summer participants proved more likely to recall notifications by app and the device icon, and were more likely to notice a temperature change and to override an event.

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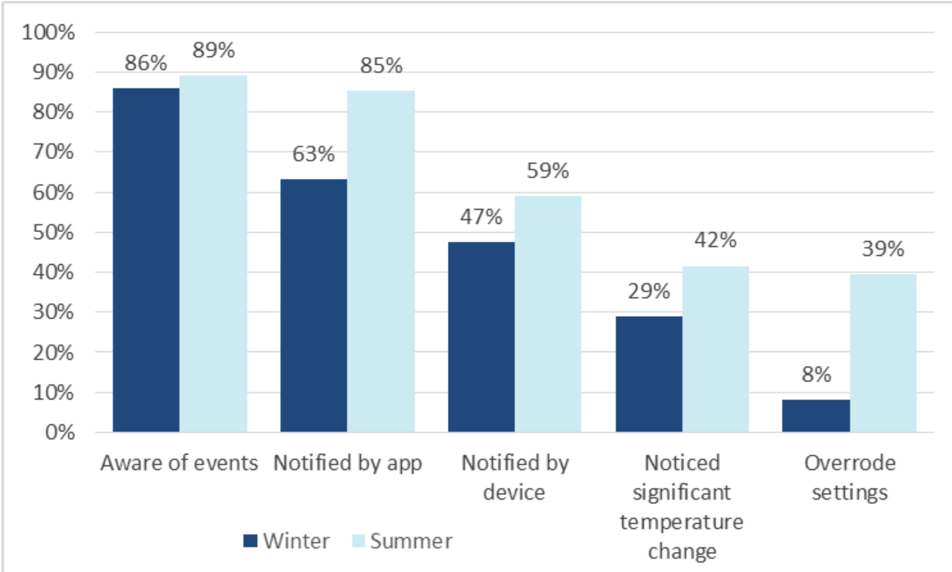
[8] Winter results derive from a survey of 50 treatment group customers, conducted immediately following a February 2016 RHR event. Summer results came from a survey of 666 treatment group customers after the season's end. Both surveys asked similarly worded customer-experience questions about the season and not about specific events.

Figure 9. Awareness and Response to Events in Winter and Summer



When asked if households took actions to keep warm during winter events, 41% of respondents reported putting on warmer clothes, 3% reported using secondary heating equipment, and 3% reported using the fireplace. When asked if the household did anything to keep cool during typical summer events, 33% of respondents reported wearing lighter or less clothing, 25% drank cool beverages, 24% moved to a cooler part of the house, and 21% turned on electric fans. Fewer than 1% of respondents turned on room air conditioners.

Appendix

Regression Model Specification

Cadmus used the following model specification to determine event-specific demand savings.

Equation 1

$$kWh_{it} = \sum_{k=0}^{23} \beta_k Hour_{kt} + \sum_{k=0}^{23} \gamma_k Hour_{kt} * DH_{it} + \sum_{k=0}^{23} \mu_k Hour_{kt} * PreTPeakkWh_{it} + \sum_{m=1}^{M} \sum_{j=1}^{3} \pi_{mj}\, I(Event\ = 1)_{mjt} + \sum_{m=1}^{M} \sum_{j=1}^{3} \theta_{mj}\, I(Treat = 1)_i * I(Event\ = 1)_{mjt} + \sum_{m=1}^{M} \sum_{n=1}^{N} \varphi_{mn}\, I(PostEvent\ = 1)_{nmt} + \sum_{m=1}^{M} \sum_{n=1}^{N} \delta_{mn}\, I(Treat = 1)_i * I(PostEvent\ = 1)_{nmt} + \sum_{m=1}^{M} \sum_{l=1}^{L} \omega_{ml}\, I(PreEvent\ = 1)_{mlt} + \sum_{m=1}^{M} \sum_{l=1}^{L} \rho_{ml}\, I(Treat = 1)_i * I(PreEvent\ = 1)_{mlt} + \varepsilon_{it}$$

Where:

kWh_{it}	=	Electricity consumption in kWh of customer *i* during hour *t*.
$Hour_{kt}$	=	Indicator variable for hour of the day. The variable equals one if hour t is the kth hour of the day, k=0, 1, 2, …, 23, and equals zero, otherwise.
β_k	=	Average load impact (kWh/hour) per customer of hour *k* on customer consumption.
DH_{it}	=	Heating or cooling degree hour for customer *i* in hour *t* for a given base temperature.
γ_k	=	Average effect per customer of a cooling degree hour on customer consumption in hour k.
μ_k	=	Average effect per customer of peak pre-treatment consumption on customer consumption in hour k.
$PreTPeakkWh_{it}$	=	Average peak consumption per hour of customer i during the pre-treatment period.
$I(Event=1)_{mjt}$	=	Indicator variable for RHR event hour. This variable equals one if hour t is the jth hour, j=1,2,…,3, of event m, m=1, 2, …, M, where M=8 for winter and M=9 for summer, and equals zero otherwise.
π_{mj}	=	Average load impact (kWh/hour) per customer during hour j of RHR event m. This load impact affects treatment and control group customers.
$I(Treat=1)_i$	=	Indicator variable for assignment to treatment group. This variable equals one if customer I was randomly assigned to the treatment group and equals zero otherwise.
θ_{mj}	=	Average load impact (kWh/hour) per treatment group customer during hour j of RHR event m.
φ_{mn}	=	Average load impact (kWh/hour) per customer during post-event hour n of event m. This load impact affects treatment and control group customers.

I(PostEvent=1)$_{nmt}$ = Indicator variable for post-event hour. This variable equals one if hour t is the nth hour after the event, n=1,2,…,N, of event m, m=1, 2, …, M, and equals zero otherwise.

δ_{mn} = Average load impact (kWh/hour) per treatment group customer during post-event hour n of event m.

ω_{ml} = Average load impact (kWh/hour) per customer during pre-event hour l of event m. This load impact affects treatment and control group customers.

I(PreEvent=1)$_{mlt}$ = Indicator variable for pre-event hour. This variable equals one if hour t is the lth hour before the event, l=1,2,…,L, of event m, m=1, 2, …, M, and equals zero otherwise.

ρ_{ml} = Average load impact (kWh/hour) per treatment group customer during pre-event hour l of event m.

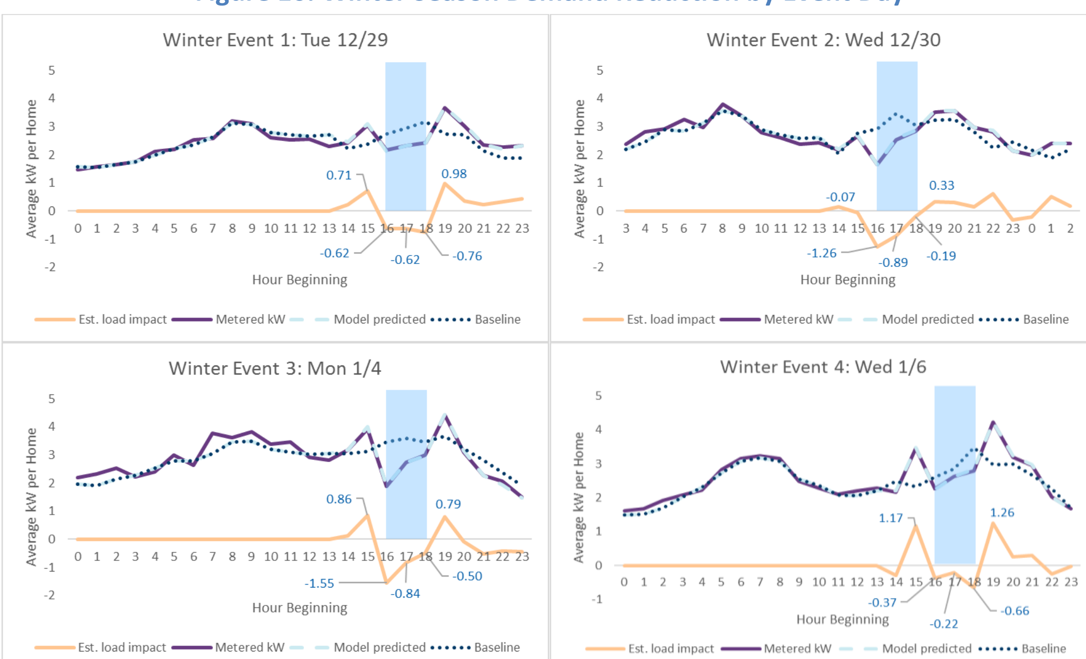
ε_{it} = Random error for customer i in hour t.

Cadmus estimated the panel model by ordinary least squares, clustering the standard errors on customers to allow within-customer correlation of hourly electricity consumption.

Detailed Impact Results

Figure 10 and Figure 11 provide detailed specific-event day impacts for the winter and summer seasons, respectively.

Figure 10. Winter Season Demand Reduction by Event Day



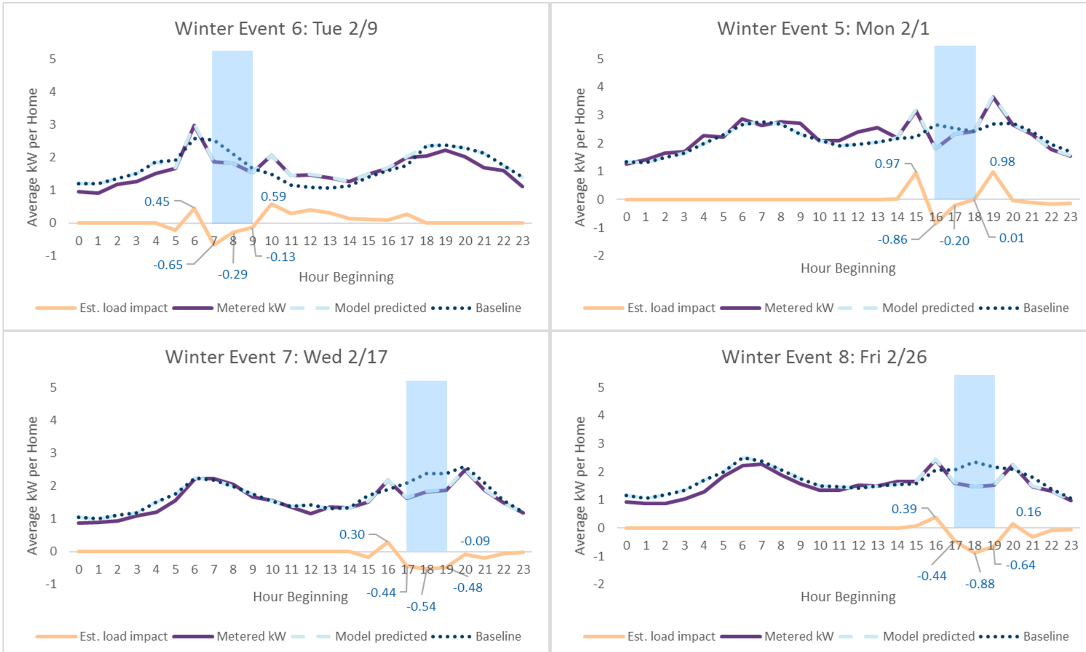
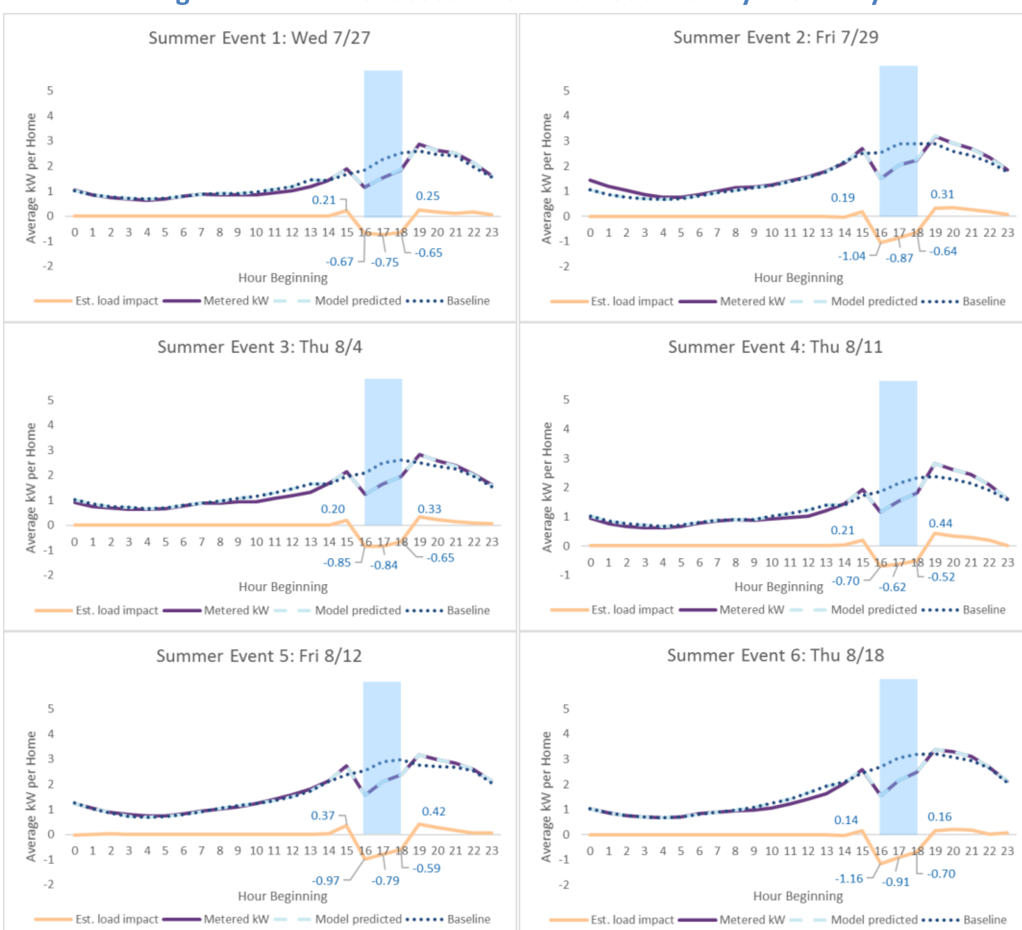
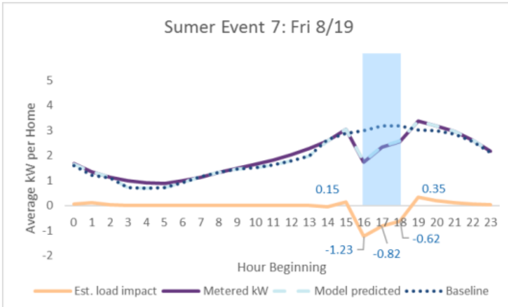
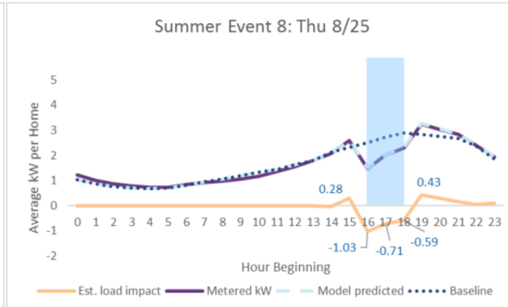


Figure 11. Summer Season Demand Reduction by Event Day







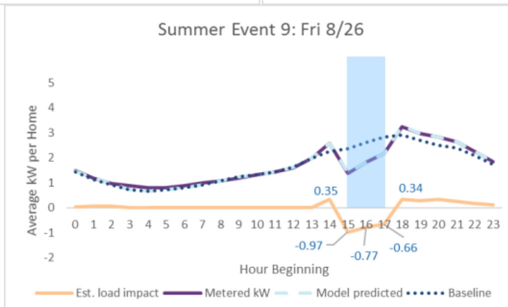


Table 6 provides additional model details regarding hourly demand impacts occurring on summer event days. As noted, the more extreme weather days (events 6 and 7) saw larger demand reductions during the first hours (over 1 kW), but decreased by nearly half by the third hour. Largely due to the increase in sample size, all event hour estimates for the summer season were statistically significant at 10%.

Table 6. Summer Hourly Impacts by Event

Event	Date	Hour	Hour Type	Outside Temp. (ºF)	Estimated Impact (kW)	SE Estimated Impact (kW)	Significant at 10%	Metered (kW)	Predicted (kW)	Baseline (kW)
1	27-Jul-16	15	Pre-Hr 1	89	0.209	0.066	Yes	1.88	1.88	1.67
1	**27-Jul-16**	**16**	**Event Hr 1**	**88**	**-0.67**	**0.06**	**Yes**	**1.15**	**1.16**	**1.83**
1	**27-Jul-16**	**17**	**Event Hr 2**	**87**	**-0.75**	**0.07**	**Yes**	**1.53**	**1.53**	**2.28**
1	**27-Jul-16**	**18**	**Event Hr 3**	**84**	**-0.65**	**0.07**	**Yes**	**1.85**	**1.85**	**2.51**
1	27-Jul-16	19	Post-Hr 1	78	0.251	0.071	Yes	2.86	2.86	2.61
1	27-Jul-16	20	Post-Hr 2	75	0.156	0.067	Yes	2.63	2.63	2.47
1	27-Jul-16	21	Post-Hr 3	72	0.101	0.066	No	2.51	2.51	2.41
1	27-Jul-16	22	Post-Hr 4	69	0.167	0.059	Yes	2.14	2.14	1.98
1	27-Jul-16	23	Post-Hr 5	67	0.048	0.050	No	1.61	1.62	1.57
1	28-Jul-16	0	Post-Hr 6	66	0.018	0.043	No	1.24	1.24	1.22
1	28-Jul-16	1	Post-Hr 7	63	0.015	0.034	No	0.98	0.98	0.96
1	28-Jul-16	2	Post-Hr 8	61	0.001	0.029	No	0.88	0.88	0.88
2	29-Jul-16	15	Pre-Hr 1	94	0.188	0.080	Yes	2.69	2.69	2.51
2	**29-Jul-16**	**16**	**Event Hr 1**	**93**	**-1.04**	**0.07**	**Yes**	**1.49**	**1.49**	**2.54**
2	**29-Jul-16**	**17**	**Event Hr 2**	**89**	**-0.87**	**0.08**	**Yes**	**2.03**	**2.04**	**2.90**
2	**29-Jul-16**	**18**	**Event Hr 3**	**84**	**-0.64**	**0.08**	**Yes**	**2.25**	**2.25**	**2.90**

Event	Date	Hour	Hour Type	Outside Temp. (^oF)	Estimated Impact (kW)	SE Estimated Impact (kW)	Significant at 10%	Metered (kW)	Predicted (kW)	Baseline (kW)
2	29-Jul-16	19	Post-Hr 1	78	0.312	0.076	Yes	3.20	3.21	2.89
2	29-Jul-16	20	Post-Hr 2	73	0.335	0.073	Yes	2.93	2.93	2.59
2	29-Jul-16	21	Post-Hr 3	70	0.264	0.068	Yes	2.69	2.68	2.42
2	29-Jul-16	22	Post-Hr 4	67	0.171	0.064	Yes	2.33	2.33	2.15
2	29-Jul-16	23	Post-Hr 5	65	0.082	0.058	No	1.84	1.84	1.76
2	30-Jul-16	0	Post-Hr 6	63	0.091	0.048	Yes	1.41	1.42	1.33
2	30-Jul-16	1	Post-Hr 7	60	0.067	0.041	Yes	1.12	1.12	1.06
2	30-Jul-16	2	Post-Hr 8	60	0.019	0.036	No	0.94	0.94	0.92
3	4-Aug-16	15	Pre-Hr 1	91	0.201	0.076	Yes	2.14	2.14	1.94
3	**4-Aug-16**	**16**	**Event Hr 1**	**90**	**-0.85**	**0.07**	**Yes**	**1.24**	**1.24**	**2.09**
3	**4-Aug-16**	**17**	**Event Hr 2**	**87**	**-0.84**	**0.07**	**Yes**	**1.64**	**1.64**	**2.49**
3	**4-Aug-16**	**18**	**Event Hr 3**	**83**	**-0.65**	**0.07**	**Yes**	**1.94**	**1.95**	**2.60**
3	4-Aug-16	19	Post-Hr 1	78	0.333	0.073	Yes	2.82	2.82	2.49
3	4-Aug-16	20	Post-Hr 2	75	0.228	0.068	Yes	2.59	2.59	2.36
3	4-Aug-16	21	Post-Hr 3	71	0.132	0.069	Yes	2.38	2.37	2.24
3	4-Aug-16	22	Post-Hr 4	69	0.077	0.059	No	2.03	2.02	1.94
3	4-Aug-16	23	Post-Hr 5	67	0.052	0.052	No	1.62	1.61	1.55
3	4-Aug-16	0	Post-Hr 6	64	0.000	0.042	No	0.92	1.02	1.02
3	5-Aug-16	1	Post-Hr 7	63	0.030	0.036	No	0.98	0.98	0.95
3	5-Aug-16	2	Post-Hr 8	61	0.019	0.029	No	0.83	0.83	0.81
4	11-Aug-16	15	Pre-Hr 1	89	0.209	0.068	Yes	1.93	1.93	1.72
4	**11-Aug-16**	**16**	**Event Hr 1**	**89**	**-0.70**	**0.06**	**Yes**	**1.16**	**1.16**	**1.86**
4	**11-Aug-16**	**17**	**Event Hr 2**	**88**	**-0.62**	**0.07**	**Yes**	**1.53**	**1.53**	**2.15**
4	**11-Aug-16**	**18**	**Event Hr 3**	**84**	**-0.52**	**0.07**	**Yes**	**1.81**	**1.82**	**2.33**
4	11-Aug-16	19	Post-Hr 1	78	0.443	0.072	Yes	2.82	2.82	2.38
4	11-Aug-16	20	Post-Hr 2	75	0.331	0.067	Yes	2.61	2.61	2.28
4	11-Aug-16	21	Post-Hr 3	73	0.303	0.064	Yes	2.45	2.45	2.14
4	11-Aug-16	22	Post-Hr 4	71	0.197	0.058	Yes	2.11	2.11	1.91
4	11-Aug-16	23	Post-Hr 5	68	0.005	0.050	No	1.60	1.60	1.59
4	12-Aug-16	0	Post-Hr 6	67	-0.031	0.045	No	1.23	1.23	1.26
4	12-Aug-16	1	Post-Hr 7	66	0.010	0.038	No	1.03	1.03	1.02
4	12-Aug-16	2	Post-Hr 8	63	0.041	0.031	No	0.88	0.89	0.84
5	12-Aug-16	15	Pre-Hr 1	96	0.365	0.085	Yes	2.73	2.74	2.37
5	**12-Aug-16**	**16**	**Event Hr 1**	**97**	**-0.97**	**0.08**	**Yes**	**1.57**	**1.57**	**2.54**
5	**12-Aug-16**	**17**	**Event Hr 2**	**94**	**-0.79**	**0.08**	**Yes**	**2.10**	**2.10**	**2.90**
5	**12-Aug-16**	**18**	**Event Hr 3**	**89**	**-0.59**	**0.08**	**Yes**	**2.38**	**2.38**	**2.97**
5	12-Aug-16	19	Post-Hr 1	83	0.416	0.082	Yes	3.18	3.18	2.76
5	12-Aug-16	20	Post-Hr 2	81	0.266	0.083	Yes	2.99	2.99	2.72
5	12-Aug-16	21	Post-Hr 3	79	0.159	0.083	Yes	2.84	2.84	2.68

Event	Date	Hour	Hour Type	Outside Temp. (°F)	Estimated Impact (kW)	SE Estimated Impact (kW)	Significant at 10%	Metered (kW)	Predicted (kW)	Baseline (kW)
5	12-Aug-16	22	Post-Hr 4	75	0.053	0.082	No	2.60	2.60	2.54
5	12-Aug-16	23	Post-Hr 5	72	0.069	0.079	No	2.13	2.13	2.06
5	13-Aug-16	0	Post-Hr 6	69	0.043	0.071	No	1.70	1.70	1.65
5	13-Aug-16	1	Post-Hr 7	68	0.088	0.049	Yes	1.34	1.34	1.25
5	13-Aug-16	2	Post-Hr 8	66	0.105	0.040	Yes	1.17	1.17	1.06
6	18-Aug-16	15	Pre-Hr 1	100	0.145	0.085	Yes	2.60	2.61	2.46
6	**18-Aug-16**	**16**	**Event Hr 1**	**98**	**-1.16**	**0.08**	**Yes**	**1.55**	**1.55**	**2.71**
6	**18-Aug-16**	**17**	**Event Hr 2**	**94**	**-0.91**	**0.08**	**Yes**	**2.14**	**2.14**	**3.05**
6	**18-Aug-16**	**18**	**Event Hr 3**	**89**	**-0.70**	**0.08**	**Yes**	**2.49**	**2.49**	**3.19**
6	18-Aug-16	19	Post-Hr 1	85	0.163	0.080	Yes	3.38	3.38	3.22
6	18-Aug-16	20	Post-Hr 2	82	0.203	0.080	Yes	3.29	3.29	3.08
6	18-Aug-16	21	Post-Hr 3	79	0.168	0.076	Yes	3.10	3.10	2.94
6	18-Aug-16	22	Post-Hr 4	75	0.026	0.071	No	2.67	2.67	2.65
6	18-Aug-16	23	Post-Hr 5	71	0.073	0.062	No	2.13	2.13	2.06
6	19-Aug-16	0	Post-Hr 6	71	0.066	0.055	No	1.67	1.66	1.60
6	19-Aug-16	1	Post-Hr 7	68	0.127	0.041	Yes	1.34	1.34	1.21
6	19-Aug-16	2	Post-Hr 8	66	0.044	0.037	No	1.14	1.14	1.09
7	19-Aug-16	15	Pre-Hr 1	99	0.149	0.085	Yes	3.04	3.04	2.89
7	**19-Aug-16**	**16**	**Event Hr 1**	**98**	**-1.23**	**0.08**	**Yes**	**1.74**	**1.75**	**2.98**
7	**19-Aug-16**	**17**	**Event Hr 2**	**96**	**-0.82**	**0.08**	**Yes**	**2.35**	**2.36**	**3.18**
7	**19-Aug-16**	**18**	**Event Hr 3**	**91**	**-0.62**	**0.08**	**Yes**	**2.56**	**2.57**	**3.19**
7	19-Aug-16	19	Post-Hr 1	84	0.350	0.078	Yes	3.37	3.38	3.03
7	19-Aug-16	20	Post-Hr 2	80	0.198	0.078	Yes	3.17	3.18	2.98
7	19-Aug-16	21	Post-Hr 3	76	0.114	0.071	No	2.96	2.96	2.85
7	19-Aug-16	22	Post-Hr 4	74	0.061	0.069	No	2.62	2.61	2.55
7	19-Aug-16	23	Post-Hr 5	72	0.047	0.065	No	2.17	2.16	2.11
7	20-Aug-16	0	Post-Hr 6	69	0.052	0.057	No	1.76	1.75	1.70
7	20-Aug-16	1	Post-Hr 7	67	0.054	0.048	No	1.41	1.40	1.35
7	20-Aug-16	2	Post-Hr 8	67	0.059	0.046	No	1.22	1.22	1.16
8	25-Aug-16	15	Pre-Hr 1	94	0.278	0.078	Yes	2.58	2.59	2.31
8	**25-Aug-16**	**16**	**Event Hr 1**	**93**	**-1.03**	**0.07**	**Yes**	**1.48**	**1.48**	**2.51**
8	**25-Aug-16**	**17**	**Event Hr 2**	**92**	**-0.71**	**0.08**	**Yes**	**2.01**	**2.02**	**2.73**
8	**25-Aug-16**	**18**	**Event Hr 3**	**87**	**-0.59**	**0.07**	**Yes**	**2.29**	**2.31**	**2.90**
8	25-Aug-16	19	Post-Hr 1	81	0.432	0.073	Yes	3.24	3.26	2.83
8	25-Aug-16	20	Post-Hr 2	77	0.297	0.075	Yes	3.04	3.05	2.75
8	25-Aug-16	21	Post-Hr 3	76	0.149	0.072	Yes	2.82	2.83	2.68
8	25-Aug-16	22	Post-Hr 4	73	0.030	0.067	No	2.39	2.39	2.36
8	25-Aug-16	23	Post-Hr 5	69	0.084	0.053	No	1.93	1.93	1.84
8	26-Aug-16	0	Post-Hr 6	67	0.029	0.046	No	1.47	1.47	1.44

Event	Date	Hour	Hour Type	Outside Temp. (°F)	Estimated Impact (kW)	SE Estimated Impact (kW)	Significant at 10%	Metered (kW)	Predicted (kW)	Baseline (kW)
8	26-Aug-16	1	Post-Hr 7	64	0.066	0.037	Yes	1.20	1.20	1.13
8	26-Aug-16	2	Post-Hr 8	62	0.054	0.029	Yes	0.97	0.97	0.92
9	26-Aug-16	14	Pre-Hr 1	95	0.347	0.080	Yes	2.59	2.59	2.25
9	**26-Aug-16**	**15**	**Event Hr 1**	**95**	**-0.97**	**0.08**	**Yes**	**1.39**	**1.40**	**2.37**
9	**26-Aug-16**	**16**	**Event Hr 2**	**95**	**-0.77**	**0.08**	**Yes**	**1.82**	**1.82**	**2.60**
9	**26-Aug-16**	**17**	**Event Hr 3**	**93**	**-0.66**	**0.08**	**Yes**	**2.17**	**2.18**	**2.84**
9	26-Aug-16	18	Post-Hr 1	86	0.344	0.076	Yes	3.25	3.26	2.91
9	26-Aug-16	19	Post-Hr 2	81	0.294	0.076	Yes	2.97	2.97	2.68
9	26-Aug-16	20	Post-Hr 3	79	0.335	0.075	Yes	2.84	2.84	2.50
9	26-Aug-16	21	Post-Hr 4	77	0.262	0.075	Yes	2.64	2.64	2.38
9	26-Aug-16	22	Post-Hr 5	73	0.166	0.065	Yes	2.26	2.26	2.09
9	26-Aug-16	23	Post-Hr 6	69	0.126	0.055	Yes	1.85	1.86	1.73
9	27-Aug-16	0	Post-Hr 7	66	0.119	0.046	Yes	1.46	1.47	1.35
9	27-Aug-16	1	Post-Hr 8	63	0.034	0.041	No	1.17	1.17	1.13

Table 7 provides additional model details regarding hourly demand impacts during winter event days. As noted, more extreme weather days (events 2 and 3) saw larger demand reductions in the first hours (over 1 kW), which then decreased significantly in the subsequent hours.

Table 7. Winter Hourly Impacts by Event

Event	Date	Hour	Hour Type	Outside Temp. (°F)	Estimated Impact (kW)	SE Estimated Impact (kW)	Significant at 10%	Metered (kW)	Predicted (kW)	Baseline (kW)
1	29-Dec-15	15	Pre-Hr 1	39	0.713	0.355	Yes	3.07	3.09	2.38
1	**29-Dec-15**	**16**	**Event Hr 1**	**39**	**-0.62**	**0.32**	**Yes**	**2.18**	**2.12**	**2.74**
1	**29-Dec-15**	**17**	**Event Hr 2**	**38**	**-0.62**	**0.36**	**Yes**	**2.33**	**2.34**	**2.95**
1	**29-Dec-15**	**18**	**Event Hr 3**	**38**	**-0.76**	**0.38**	**Yes**	**2.42**	**2.43**	**3.19**
1	29-Dec-15	19	Post-Hr 1	38	0.977	0.411	Yes	3.68	3.71	2.73
1	29-Dec-15	20	Post-Hr 2	38	0.349	0.394	No	3.03	3.07	2.72
1	29-Dec-15	21	Post-Hr 3	37	0.243	0.314	No	2.36	2.38	2.14
1	29-Dec-15	22	Post-Hr 4	36	0.327	0.307	No	2.27	2.21	1.88
1	29-Dec-15	23	Post-Hr 5	34	0.430	0.402	No	2.33	2.33	1.90
1	30-Dec-15	0	Post-Hr 6	33	0.206	0.294	No	1.94	1.94	1.74
1	30-Dec-15	1	Post-Hr 7	32	0.311	0.309	No	1.98	1.98	1.67
1	30-Dec-15	2	Post-Hr 8	32	0.478	0.330	No	2.23	2.23	1.76
2	30-Dec-15	15	Pre-Hr 1	40	-0.065	0.485	No	2.65	2.69	2.76
2	**30-Dec-15**	**16**	**Event Hr 1**	**38**	**-1.26**	**0.29**	**Yes**	**1.64**	**1.66**	**2.92**
2	**30-Dec-15**	**17**	**Event Hr 2**	**36**	**-0.89**	**0.44**	**Yes**	**2.55**	**2.58**	**3.47**

Event	Date	Hour	Hour Type	Outside Temp. (^oF)	Estimated Impact (kW)	SE Estimated Impact (kW)	Significant at 10%	Metered (kW)	Predicted (kW)	Baseline (kW)
2	**30-Dec-15**	**18**	**Event Hr 3**	**35**	**-0.19**	**0.44**	**No**	**2.84**	**2.88**	**3.06**
2	30-Dec-15	19	Post-Hr 1	35	0.335	0.518	No	3.53	3.58	3.24
2	30-Dec-15	20	Post-Hr 2	35	0.300	0.499	No	3.56	3.56	3.26
2	30-Dec-15	21	Post-Hr 3	35	0.157	0.366	No	2.97	2.97	2.82
2	30-Dec-15	22	Post-Hr 4	34	0.621	0.399	No	2.82	2.86	2.24
2	30-Dec-15	23	Post-Hr 5	34	-0.308	0.392	No	2.14	2.16	2.46
2	31-Dec-15	0	Post-Hr 6	34	-0.196	0.342	No	1.99	1.98	2.18
2	31-Dec-15	1	Post-Hr 7	33	0.508	0.353	No	2.39	2.40	1.89
2	31-Dec-15	2	Post-Hr 8	33	0.184	0.362	No	2.39	2.40	2.21
3	4-Jan-16	15	Pre-Hr 1	35	0.862	0.492	Yes	3.94	4.00	3.14
3	**4-Jan-16**	**16**	**Event Hr 1**	**34**	**-1.55**	**0.35**	**Yes**	**1.90**	**1.92**	**3.47**
3	**4-Jan-16**	**17**	**Event Hr 2**	**34**	**-0.84**	**0.41**	**Yes**	**2.73**	**2.75**	**3.59**
3	**4-Jan-16**	**18**	**Event Hr 3**	**34**	**-0.50**	**0.42**	**No**	**2.99**	**2.98**	**3.48**
3	4-Jan-16	19	Post-Hr 1	33	0.790	0.513	No	4.41	4.45	3.66
3	4-Jan-16	20	Post-Hr 2	33	-0.076	0.415	No	3.11	3.15	3.23
3	4-Jan-16	21	Post-Hr 3	33	-0.532	0.319	Yes	2.28	2.28	2.81
3	4-Jan-16	22	Post-Hr 4	32	-0.418	0.334	No	2.08	1.95	2.37
3	4-Jan-16	23	Post-Hr 5	32	-0.453	0.241	Yes	1.51	1.46	1.92
3	5-Jan-16	0	Post-Hr 6	33	-0.130	0.280	No	1.58	1.60	1.73
3	5-Jan-16	1	Post-Hr 7	33	0.099	0.308	No	1.71	1.73	1.63
3	5-Jan-16	2	Post-Hr 8	33	0.180	0.307	No	2.23	2.25	2.07
4	6-Jan-16	15	Pre-Hr 1	41	1.166	0.483	Yes	3.46	3.48	2.31
4	**6-Jan-16**	**16**	**Event Hr 1**	**39**	**-0.37**	**0.30**	**No**	**2.26**	**2.25**	**2.61**
4	**6-Jan-16**	**17**	**Event Hr 2**	**39**	**-0.22**	**0.32**	**No**	**2.63**	**2.63**	**2.85**
4	**6-Jan-16**	**18**	**Event Hr 3**	**38**	**-0.66**	**0.38**	**Yes**	**2.79**	**2.82**	**3.48**
4	6-Jan-16	19	Post-Hr 1	38	1.256	0.493	Yes	4.23	4.23	2.97
4	6-Jan-16	20	Post-Hr 2	38	0.248	0.390	No	3.19	3.23	2.99
4	6-Jan-16	21	Post-Hr 3	38	0.300	0.381	No	2.95	2.97	2.67
4	6-Jan-16	22	Post-Hr 4	37	-0.248	0.361	No	2.03	2.02	2.27
4	6-Jan-16	23	Post-Hr 5	37	-0.030	0.287	No	1.67	1.66	1.69
4	7-Jan-16	0	Post-Hr 6	35	-0.088	0.264	No	1.56	1.56	1.64
4	7-Jan-16	1	Post-Hr 7	36	0.403	0.287	No	1.94	1.95	1.54
4	7-Jan-16	2	Post-Hr 8	36	0.171	0.261	No	1.93	1.93	1.76
5	1-Feb-16	15	Pre-Hr 1	45	0.966	0.472	Yes	3.16	3.20	2.24
5	**1-Feb-16**	**16**	**Event Hr 1**	**45**	**-0.86**	**0.38**	**Yes**	**1.81**	**1.81**	**2.68**
5	**1-Feb-16**	**17**	**Event Hr 2**	**44**	**-0.20**	**0.33**	**No**	**2.33**	**2.34**	**2.53**
5	**1-Feb-16**	**18**	**Event Hr 3**	**43**	**0.01**	**0.33**	**No**	**2.43**	**2.43**	**2.42**
5	1-Feb-16	19	Post-Hr 1	42	0.985	0.398	Yes	3.65	3.69	2.70
5	1-Feb-16	20	Post-Hr 2	42	-0.023	0.340	No	2.67	2.70	2.72

Event	Date	Hour	Hour Type	Outside Temp. (^oF)	Estimated Impact (kW)	SE Estimated Impact (kW)	Significant at 10%	Metered (kW)	Predicted (kW)	Baseline (kW)
5	1-Feb-16	21	Post-Hr 3	41	-0.100	0.277	No	2.34	2.33	2.43
5	1-Feb-16	22	Post-Hr 4	41	-0.169	0.257	No	1.78	1.79	1.96
5	1-Feb-16	23	Post-Hr 5	40	-0.136	0.299	No	1.56	1.58	1.72
5	2-Feb-16	0	Post-Hr 6	38	0.161	0.217	No	1.47	1.50	1.34
5	2-Feb-16	1	Post-Hr 7	37	0.037	0.243	No	1.45	1.46	1.42
5	2-Feb-16	2	Post-Hr 8	36	-0.213	0.230	No	1.48	1.50	1.72
6	9-Feb-16	6	Pre-Hr 1	40	0.449	0.368	No	2.98	3.02	2.57
6	**9-Feb-16**	**7**	**Event Hr 1**	**40**	**-0.65**	**0.29**	**Yes**	**1.86**	**1.88**	**2.53**
6	**9-Feb-16**	**8**	**Event Hr 2**	**45**	**-0.29**	**0.26**	**No**	**1.82**	**1.82**	**2.12**
6	**9-Feb-16**	**9**	**Event Hr 3**	**51**	**-0.13**	**0.26**	**No**	**1.53**	**1.53**	**1.66**
6	9-Feb-16	10	Post-Hr 1	55	0.588	0.271	Yes	2.08	2.08	1.49
6	9-Feb-16	11	Post-Hr 2	57	0.287	0.202	No	1.45	1.45	1.16
6	9-Feb-16	12	Post-Hr 3	58	0.395	0.188	Yes	1.47	1.48	1.09
6	9-Feb-16	13	Post-Hr 4	59	0.311	0.206	No	1.37	1.39	1.08
6	9-Feb-16	14	Post-Hr 5	60	0.130	0.179	No	1.26	1.26	1.13
6	9-Feb-16	15	Post-Hr 6	58	0.104	0.190	No	1.49	1.49	1.39
6	9-Feb-16	16	Post-Hr 7	57	0.084	0.243	No	1.67	1.68	1.60
6	9-Feb-16	17	Post-Hr 8	54	0.267	0.223	No	2.00	2.02	1.75
7	17-Feb-16	16	Pre-Hr 1	53	0.297	0.247	No	2.18	2.19	1.89
7	**17-Feb-16**	**17**	**Event Hr 1**	**52**	**-0.44**	**0.21**	**Yes**	**1.63**	**1.64**	**2.09**
7	**17-Feb-16**	**18**	**Event Hr 2**	**49**	**-0.54**	**0.24**	**Yes**	**1.83**	**1.84**	**2.38**
7	**17-Feb-16**	**19**	**Event Hr 3**	**48**	**-0.48**	**0.25**	**Yes**	**1.88**	**1.89**	**2.37**
7	17-Feb-16	20	Post-Hr 1	48	-0.089	0.283	No	2.49	2.51	2.60
7	17-Feb-16	21	Post-Hr 2	47	-0.203	0.220	No	1.87	1.89	2.09
7	17-Feb-16	22	Post-Hr 3	47	-0.065	0.183	No	1.49	1.49	1.56
7	17-Feb-16	23	Post-Hr 4	46	-0.028	0.142	No	1.19	1.17	1.20
7	18-Feb-16	0	Post-Hr 5	45	-0.193	0.145	No	0.98	0.99	1.18
7	18-Feb-16	1	Post-Hr 6	44	0.124	0.136	No	1.03	1.03	0.90
7	18-Feb-16	2	Post-Hr 7	44	-0.110	0.150	No	1.08	1.09	1.20
7	18-Feb-16	3	Post-Hr 8	45	0.127	0.152	No	1.41	1.44	1.31
8	26-Feb-16	16	Pre-Hr 1	51	0.387	0.319	No	2.44	2.46	2.08
8	**26-Feb-16**	**17**	**Event Hr 1**	**50**	**-0.44**	**0.20**	**Yes**	**1.61**	**1.62**	**2.07**
8	**26-Feb-16**	**18**	**Event Hr 2**	**50**	**-0.88**	**0.28**	**Yes**	**1.47**	**1.48**	**2.36**
8	**26-Feb-16**	**19**	**Event Hr 3**	**50**	**-0.64**	**0.24**	**Yes**	**1.53**	**1.53**	**2.17**
8	26-Feb-16	20	Post-Hr 1	50	0.156	0.248	No	2.26	2.25	2.10
8	26-Feb-16	21	Post-Hr 2	49	-0.310	0.187	Yes	1.48	1.49	1.80
8	26-Feb-16	22	Post-Hr 3	50	-0.070	0.159	No	1.32	1.33	1.39
8	26-Feb-16	23	Post-Hr 4	50	-0.053	0.135	No	0.99	1.00	1.05
8	27-Feb-16	0	Post-Hr 5	50	-0.060	0.138	No	0.94	0.94	1.00

Event	Date	Hour	Hour Type	Outside Temp. (°F)	Estimated Impact (kW)	SE Estimated Impact (kW)	Significant at 10%	Metered (kW)	Predicted (kW)	Baseline (kW)
8	27-Feb-16	1	Post-Hr 6	52	0.063	0.153	No	0.92	0.94	0.88
8	27-Feb-16	2	Post-Hr 7	52	0.093	0.150	No	0.93	0.93	0.83
8	27-Feb-16	3	Post-Hr 8	52	-0.065	0.143	No	0.92	0.93	0.99

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