Portland General Electric Company
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May 31, 2016

Via Email
puc.filingcenter@state.or.us

OPUC Filing Center
201 High Street SE, Suite 100
PO Box 1088
Salem, OR 97308-1088

RE: **2016 Smart Grid Report (Order No. 12-158)**

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 2016 Smart Grid Report, PGE held a Smart Grid workshop on May 13, 2016 to receive and consider feedback from stakeholders, and, where applicable, has included additional information in the report to address comments. Pursuant to Order No. 12-158, PGE provides the attached 2016 Smart Grid Report.

If you have any questions or require further information, please call Aaron Milano at (503) 464-7547 or 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 56 Service List

2016 Smart Grid Report

June 1, 2016


Portland General Electric

Contents

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)

Section 1. Executive Summary

Background

This report is PGE's fourth Smart Grid Annual Report filing in compliance with OPUC Order No. 12-158 in Docket No. UM 1460. This report includes an update on PGE's smart grid initiatives including each of the eleven conditions outlined by the OPUC in response to the previous report filing. In preparation for filing, PGE provided external stakeholders opportunities to provide feedback on this report.

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.

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.

- **Foundational:** Hardware and software that enable deployment of smart grid initiatives, allow customers to realize maximum value of smart grid initiatives, and improve cybersecurity. Foundational initiatives include:
    - Advanced Metering Infrastructure
    - Communications Upgrades
    - Energy Management System & Automated Generation Control
    - State Estimator
    - Real-time Contingency Analysis
    - T&D Analytics
    - Energy Information Systems:
        - Energy Tracker
        - Energy Expert
    - Outage Management System
    - Geographical Information System
    - Customer Information System
    - Meter Data Management System

- **Grid optimization:** 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. Grid optimization initiatives include:
    - SCADA (Supervisory Control and Data Acquisition)
    - Substation Remote Access Server
    - Substation Automation
    - Distribution Automation
    - Conservation Voltage Reduction
    - Energy Storage
    - Salem Smart Power Project
    - Synchrophasor Deployment
    - Fault Detection (Distribution)
    - Remedial Action Schemes
    - Distribution Temperature Sensing
    - Voltage Disturbance Detection
    - Travelling Wave Fault Location Protective Relays
    - Remote Service Detection
    - Solar Grid Integration Systems
    - T&D Asset Monitoring

- **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 customer reliability, and reducing peak demand. Customer engagement initiatives include:
    - Dispatchable Standby Generation
    - Microgrids
    - Pricing Programs:
        - Time of Day Pricing
        - Time of Use Pricing
        - Critical Peak Pricing
        - Flex: Pricing Research Pilot
    - Demand Response
        - Firm Load Reduction Program
        - Energy Partner Pilot
        - SSPC Direct Load Control
        - Smart Thermostat
        - EV Smart Charging
    - Battery Back-up

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.

Section 2. Background

A. Smart Grid Report History & 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:

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 fourth report in response to Order No. 12-158:

Table 1 – 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

B. OPUC Recommendations

In response to PGE's 2015 report, the OPUC made several recommendations in Order No. 15-314, which are summarized in Table 2. Each recommendation is addressed in this report on the page listed.

Table 2 – Summary of Recommendations from Order No. 15-314

Category	Recommendation	Page(s)
Smart Grid Strategy	Provide an interim update on its efforts to develop a vision & road map as part of its 2016 Smart Grid Report at a Commission workshop.	16
Pricing & Demand Response	Provide the results of the dynamic pricing stakeholder process for developing a cost-effective methodology, the exploration of cycling load, tracking of customer fatigue, and the exploration of enabling technologies.	66
Pricing & Demand Response	Include any preliminary results and findings from its dynamic pricing pilot & DLC pilot.	68-69
Smart Grid Metrics	Continue the stakeholder process for researching and including additional reliability and operational metrics in its next smart grid report as well as to improve existing metrics.	59
Synchrophasors	Include Project-X's scope & timeline as well as the projected costs & benefits.	70
Energy Storage	Work with Staff & other SSPP stakeholders to produce a comprehensive report with subsequent, recurring updates as work continues on the SSPP.	75
Pricing	Conduct a stakeholder process with Staff and stakeholders when it considers future pricing programs in order to assist and guide pilot and program design and implementation.	n/a

Category	Recommendation	Page(s)
Smart Inverters	Continue to document & report on efforts related to smart inverters.	90
Customer Engagement	PGE begin a recurring stakeholder meeting where Staff & stakeholders discuss customer education, outreach, marketing, and related strategies.	91
Research & pilots	PGE should include the status of non-wire alternative distribution upgrade research, including possible pilot projects.	99
Research & pilots	PGE should provide a summarizing table of all research, development, and pilot projects, their respective descriptions, expected benefits and costs.	100

C. 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 3 – Stakeholder Engagement

Date	Milestone
02/09/2016	Smart Grid Workshop: Metrics & Customer Outreach
03/15/2016	Smart Grid Road Map Public meeting
04/29/2016	Draft report shared with key stakeholders
05/11/2016	Smart grid report workshop with key stakeholders
05/11/2016	Last day comments received

PGE received informal comments from:

- OPUC Staff

The following organizations attended a draft review workshop held on May 11, 2016:

- OPUC Staff
- Citizens' Utility Board
- Northwest Energy Coalition
- Oregon Department of Energy
- Portland General Electric

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 2015, PGE engaged customers on a variety of smart-grid related topics:

- Pricing pilot: messaging focus groups
- Pricing pilot: discrete choice survey for market model
- Energy Partner: in-depth customer interviews
- Energy storage residential survey
- Customer satisfaction surveys: MSI & JD Power

Section 3. Smart Grid Strategy

A. History of Smart Grid Strategy

PGE has previously reported[1] a smart grid strategy consistent with OPUC's goals:

- *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 has been valuable in guiding PGE research, investment, and planning around smart grid technologies. However, 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.

[1] PGE Smart Grid Report 2013 & 2014

The task force included SMEs from the following teams:

- Business Development
- Corporate Planning
- Corporate R&D
- Customer Insights
- Customer Specialized Programs
- Enterprise Telecommunications
- Information Technology
- Innovative Technologies
- Integrated Resource Planning
- Network Data Operations
- Rates & Regulatory Affairs
- Resource Strategy
- Retail Strategy & Development
- Strategic Asset Management
- Substation Administration
- System Protection & Automation
- T&D Engineering
- T&D Planning & Project Management

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 Smart Grid Maturity Model 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

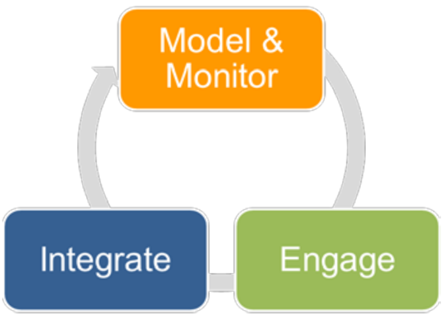
The SGMM process is essential for developing a road map that is consistent with PGE's current state and corporate strategies. It calls for:

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 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 a public meeting on March 15, 2016.

B. 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:



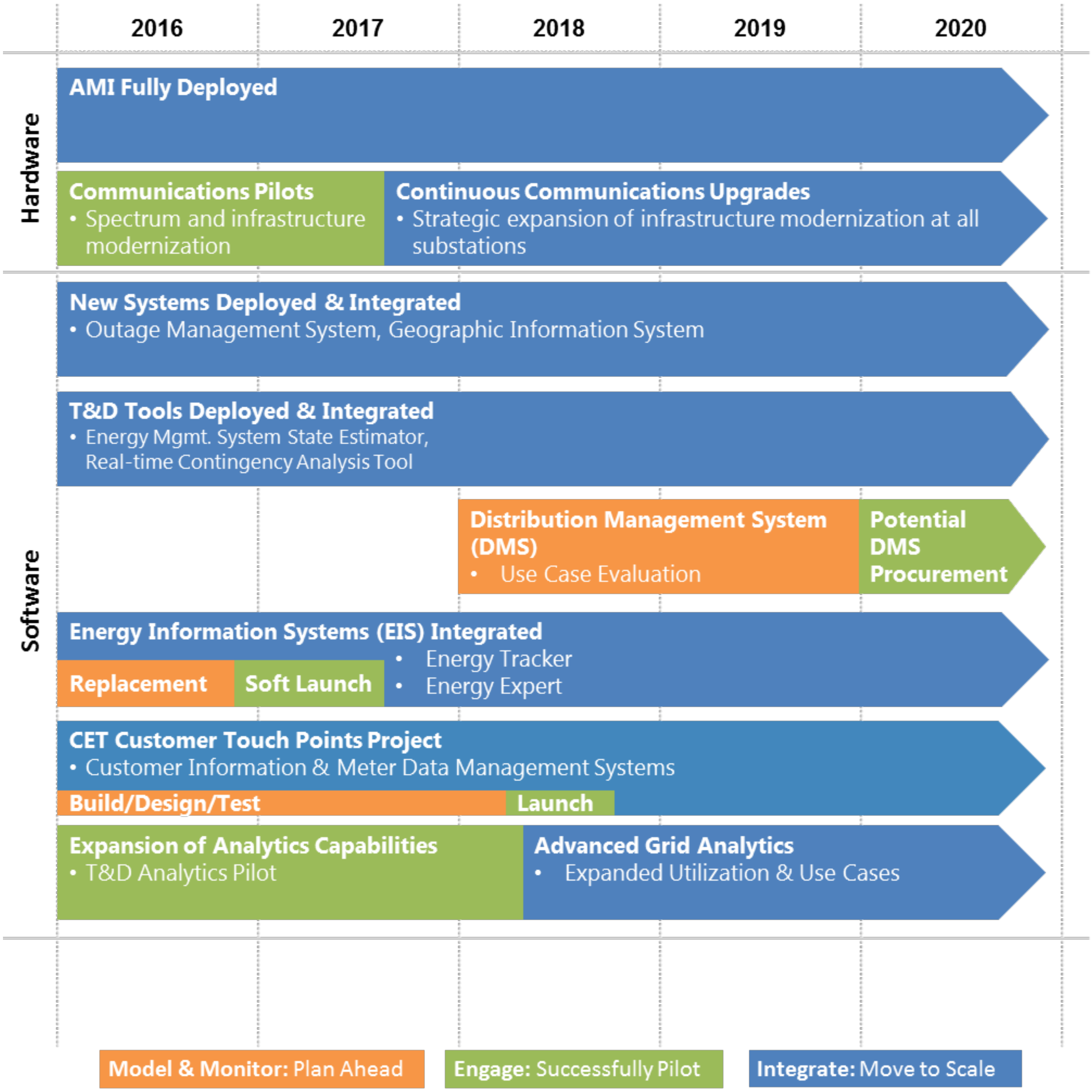
- **Model & Monitor (Plan Ahead)**:
  Leverage customer trends, grid data, policies, and modeling, to plan ahead by identifying potential pilots, demonstrations and programs.
  By understanding our system, customers, and industry trends, we can effectively plan and prioritize our research and development 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.
- **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).

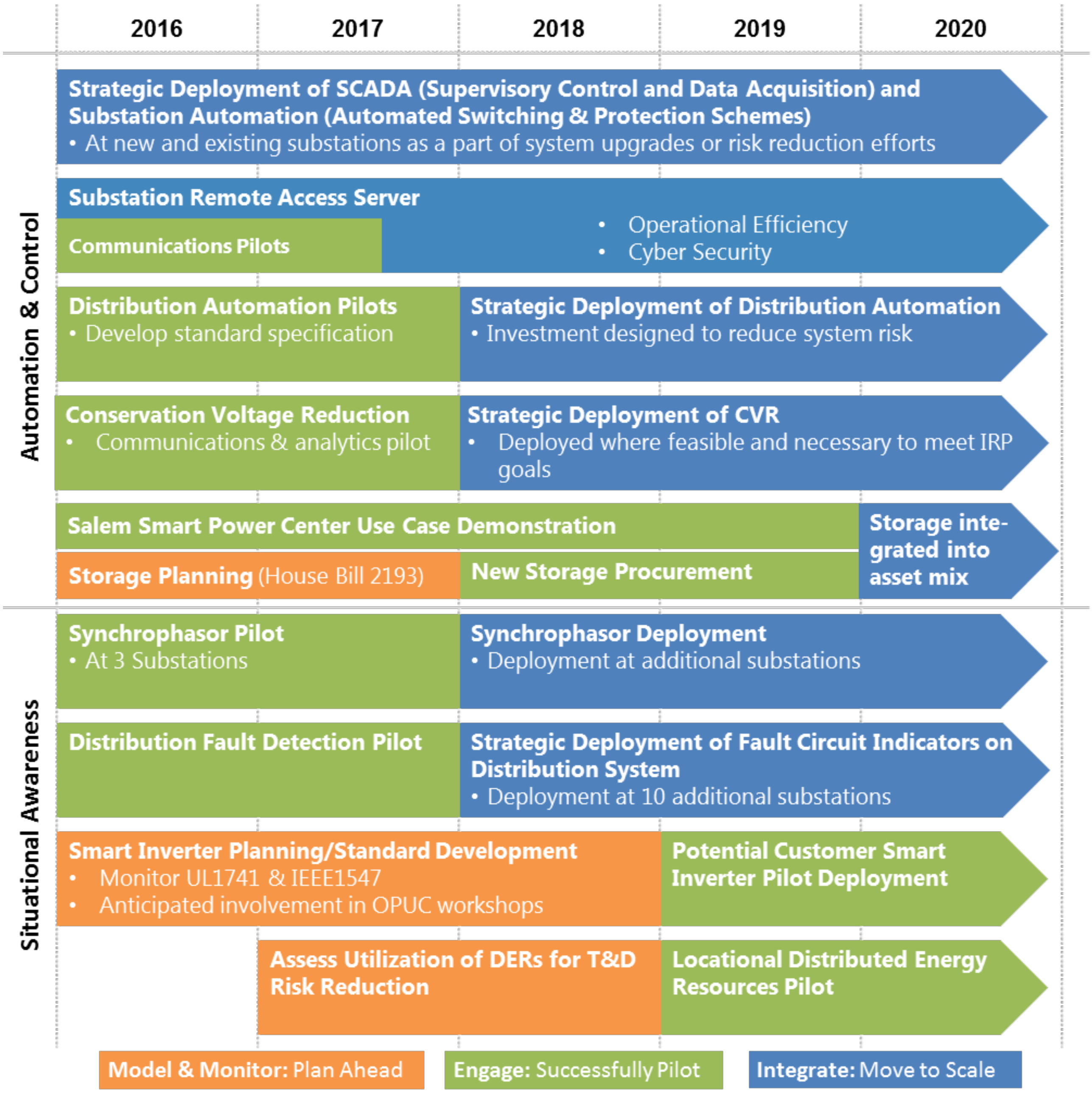
C. Road Map

At a public meeting on March 15, 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.

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

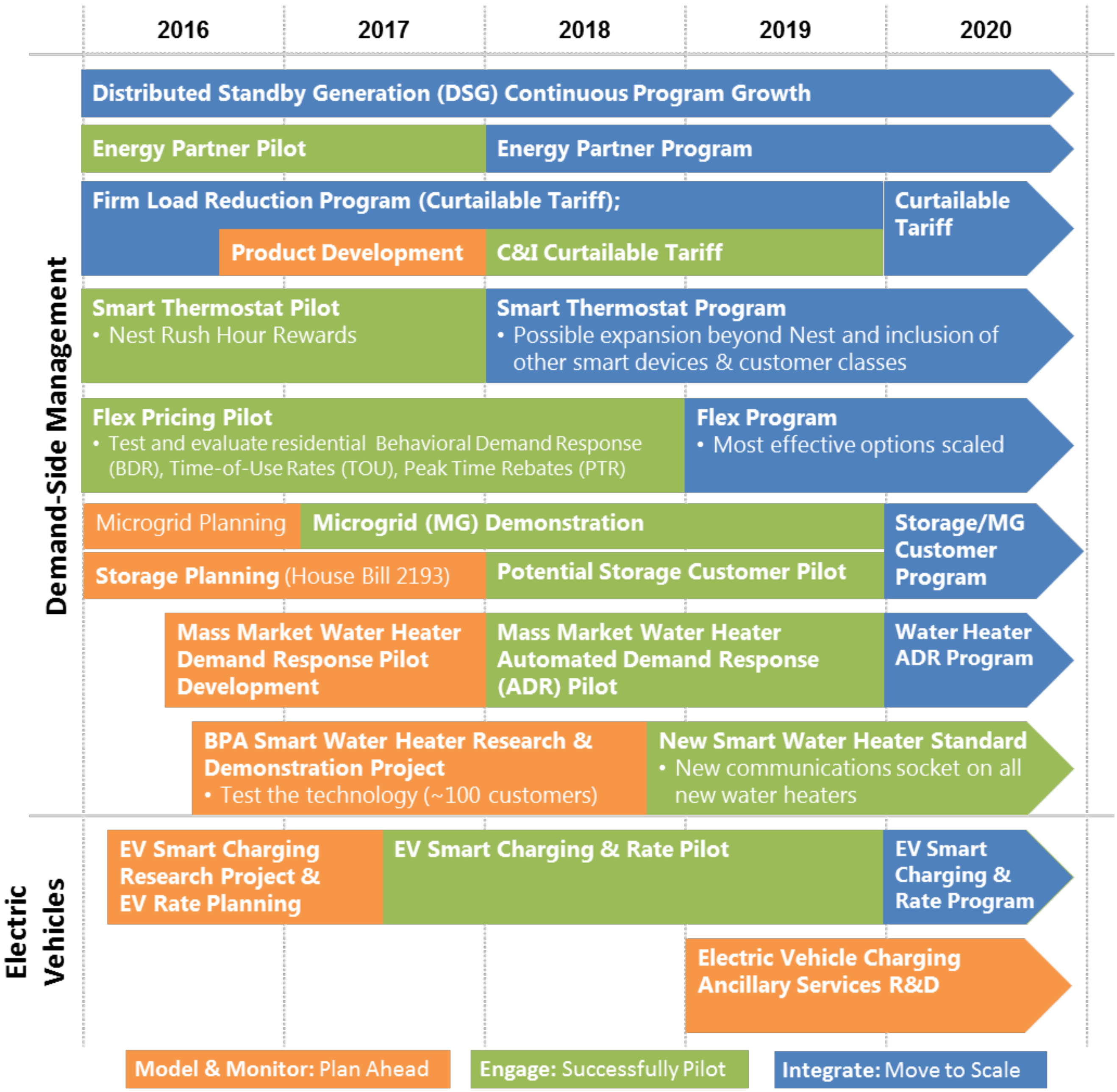


Grid Optimization: System hardware and tools that automate processes and improve situational awareness to reduce system risk and improve reliability of the transmission & distribution networks by: improving restoration time, avoiding outages, and informing investment & design



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



Section 4. PGE Commitment to Smart Grid

A. Alignment with Integrated Resource Plan (IRP)

In the decades ahead, the Smart Grid will support 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 to help dynamically balance supply and demand, which may ultimately mitigate the need for transmission upgrades and the development of fossil-fuel generation for load following. 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 included in PGE's IRP process.

Table 4 – 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 5 – 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

B. 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

C. Project Development Process

PGE utilizes a disciplined approach to evaluating new smart grid opportunities. The methodology is modelled after EPRI's *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects*:

1. Describe the project
2. Identify Smart Grid functions provided
3. Assess project's principal characteristics
4. Map functions to benefits
5. Establish project baseline(s)
6. Identify and compile the data
7. Quantify the overall impact
8. Monetize the benefits
9. Estimate the relevant costs
10. Compare costs and benefits

PGE has a cross-functional committee that exists to promote, assess, and implement innovative technologies that require research and development. This team of SMEs assesses technologies and proposals on a regular basis to ensure projects align with PGE's smart grid strategy.

Additionally, PGE conducts customer research on a regular basis to ensure customer expectations are aligned with the company's Smart Grid efforts. PGE leverages this research to inform our product and program offerings and identify ways to better engage customers in the Smart Grid. Most recent targeted studies include an electric vehicle survey and a pricing program survey with subsequent focus groups.

As PGE develops pilots/studies, the Company will share results with OPUC staff and interested stakeholders, offering an opportunity for business cases for major investments to be vetted prior to deployment.

Section 5. Status of Current Smart Grid Initiatives

PGE has completed and is actively deploying a variety of smart grid initiatives across three categories: Foundational, Grid Optimization, and Customer Engagement. This section of the report summarizes smart grid initiatives across both categories that are completed or in progress.

A. Foundational

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

Advanced Metering Infrastructure (AMI) Deployment

Description: 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

Continuous Communication Upgrades

Description: 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. PGE procured a block of radio spectrum in fall 2015, with the primary purpose of replacing the land-mobile radio system to increase reliability and safety. Additionally, the spectrum can serve a variety of deployments of smart grid initiatives including but not limited to: distribution automation, demand management programs, conservation voltage reduction, SCADA traffic, 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. Communications infrastructure meets NERC Critical Infrastructure Protection (CIP) compliance requirement.

Status: Active Deployment

Next steps: PGE will construct necessary base stations to ensure system-wide connectivity for the radio spectrum in 2016 and 2017 with intent to go live in 2018. Additionally, 92 of our 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 planning to upgrade communication infrastructure to those substations by 2020. 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.

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

Description: 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)

Description: 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)

Description: 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.

T&D Analytics

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.

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 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

Description: 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 200,000 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.[2]

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 this year to improve the customer experience. The new system, which is slated to go live in Q4 2016, 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. The new commercial platform should facilitate customer compliance with the City of Portland's energy reporting mandate.

[2] Energy Tracker savings data is based on program evaluation in 2013.

Energy Expert

Description: 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 calculate energy savings and to track the effects of 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 user understand the benefits of monitoring daily energy usage. Currently 105 customers are utilizing Energy Expert on over 500 meters.

Status: Active Deployment

Systems Development

PGE launched a broad initiative in 2013 to upgrade technology infrastructure and streamline work processes as a core component of our Transmission & Distribution (T&D) Transformation Project. The 'NextWave Project' will ultimately replace approximately 30 antiquated enterprise systems with more efficient and integrated tools that will make information more accessible and will enable advanced data analytics and process automation. The following tools are foundational in PGE's grid optimization efforts:

Outage Management System (OMS)

Description: 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)

Description: 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: Customer Touchpoints Project

Description: During the next five years, PGE will continue our work towards a flexible platform for initiating products and services that leverage our previous investments in our Smart Meter infrastructure. PGE will be replacing its vintage **Customer Information System (CIS)** and **Meter Data Management System (MDMS)** with systems that can more easily and efficiently enable new distributed resources and the delivery of pricing and demand-side management programs to our customers. These systems are critical predecessors to the full-scale deployment as well as quick and low-cost adoption of many of our customer pricing and demand response programs.

Status: Planned Deployment

B. 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.

SCADA (Supervisory Control and Data Acquisition)

Description: Deployment of SCADA on substations increases visibility of the grid to T&D operations and reduces the likelihood and durations of outages. Currently 76% of PGE substations are controlled by SCADA. SCADA was deployed at 6 additional substations in 2015. PGE is actively deploying SCADA controls at substations. PGE is also strategically adding SCADA to reclosers, tie switches, 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 3 substations and replacing multiple aging systems in 2016. 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

Description: 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, 24% of substations and plants 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

Description: 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.

- **Automatic switching**: distribution substations automatically attempt to restore power after outages
- **Automated protection 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.

Energy Storage

Description: 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. To date, the team has developed a project vision which is to create a diversified storage portfolio (in location and storage type) while integrating all resources through PGE system operations. 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/decarbonization.

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 6 – Gales Creek Reliability Metrics, 2006-2015[3]

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

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.

[3] PGE Reliability Reports 2008-2015

Conservation Voltage Reduction (CVR)

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%. 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

Next steps: 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.

Salem Smart Power Project (SSPP)

Description: 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 formally initiated in 2010 and concluded in 2014. Key project features and demonstrations included[4]:

- **Storage**: An advanced lithium ion battery system (1.25 MWh, 5 MW) provides uninterrupted power for testing microgrid concepts, real and reactive power regulation for voltage regulation and stability, as well as power cost hedging and ancillary services.
- **High Reliability/Microgrid**: A feeder segment can be automatically isolated from the grid with loads that can then be served with local Dispatchable Standby Generation (DSG) and the battery. In this condition, as long as there is fuel to power the six DSG generators, a microgrid is formed that can be operated independently of the PGE regional grid.
- **Self-Correcting Feeder**: PGE explored various concepts related to increased reliability utilizing the Salem Smart Power Center. For example, distributed automation schemes using pole top switches automatically locate and isolate faulted portions of the feeder. The battery system can maintain voltage on the unfaulted portion while the DSG generators are started and brought on line. These high reliability concepts can improve system efficiency and customer reliability.
- **Transforming Renewable Energy Assets into Dispatchable Energy Solutions**: Using the Salem Smart Power Center, PGE worked with neighboring Kettle Brand and their 114 kW solar photovoltaic system to develop new energy storage controls for more efficient integration of solar and possibly, in the future, wind resources.
- **Transactive Control**: A fully automated control system provided real-time solutions for regional power issues such as low/high wind, high/low prices for transmission-supplied power to regional distribution resources and regional congestion management, enabling power generation to be regionally coordinated with energy prices.
- **Frequency Regulation**: PGE's 5 MW, 1.25 MWh lithium ion battery inverter system at the Salem Smart Power Center has demonstrated an ability to respond to major system frequency events. In February, 2015,

[4] All of the assets and program features resulting directly from the 5-year PNNL SSPP demonstration have been put on hiatus. This is required as PGE pursues additional use and valuation test cases beyond the original effort. It also results from the fact that the SSPP programming allowed deployment of only one use case at a time: (1) for operational safety and (2) to minimize variables as new use cases are explored.

BPA Balancing Authority experienced a loss of 660 MW of generation. The automated battery response proved to be a fast and reliable tool to help stabilize WECC interconnection frequency. Since the close of the formal SSPP effort, frequency regulation in support PGE's regulatory requirements as found in NERC BAL-003-1 has been the principal use of the battery inverter system at the Salem Smart Power Center.

Status: Complete (testing on-going)

Next Steps: In 2016 and 2017 PGE and PNNL, with funding received from the US Department of Energy, will model the financial benefits of providing multiple services and develop an optimal control strategy for having the battery provide multiple use cases simultaneously. PGE will then work with PSU to implement PNNL's algorithm at SSPC.

Fault Detection (Distribution)

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. In 2016, PGE will test use cases for the FCIs and 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 2017 or 2018.

Synchrophasors on Transmission System

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. 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[5]
- 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. A network test server was completed in 2015.

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. Additional detail on PGE's investment in synchrophasors is in Appendix 7.

[5] 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.[6] PGE has established RAS at Grand Ronde & is designing a RAS at Rounde 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 opportunity after full deployment of the EMS SE and RTCA tools.

Distribution Temperature Sensing (DTS)

Description: 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)

Description: 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 113 i-Grid detection devices on 109 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.

[6] NERC "Remedial Action Scheme Definition Development"

Travelling Wave Fault Location Protective Relays

Description: 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

Description: 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 28 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: Though no DGAs were installed in 2015, the Company plans to upgrade an additional 9 units in 2016. 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.

Remote Service Detection (Outage Confirmation)

Description: PGE has built systems that utilize Smart Meter data to confirm outages prior to dispatching crews. Smart meters are 'pinged' when customers report an isolated outage, avoiding unnecessary truck rolls in situations where PGE service to the home has not been interrupted.

Status: Complete

Solar Energy Grid Integration Systems (SEGIS)

Description: 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.

Additional information on utilizing smart inverters for PV resource integration can be found in Appendix 9.

Status: Complete

C. Customer Engagement

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

Dispatchable Standby Generation (DSG)

Description: 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 105.7 MW of capacity from these generators which contribute to the Company's non-spinning reserves.

Status: Active Deployment

Next Steps: The Company is evaluating DSG plans as a part of the current IRP process.

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

Description: 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):

Description: A voluntary program available 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 Price/Critical Peak Pricing (CPP)

Description: 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

Firm Load Reduction for Commercial & Industrial Customers

Description: 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 via Schedule 77. 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. 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.

Status: Active Deployment

Flex: Pricing Research Pilot

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).[7]

The pilot will test 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 05/26/16, over 1,500 customers have enrolled to participate in the pilot. Participants' new rate schedules will take effect within 1-2 months of their enrollment.

Status: Pilots and Evaluation

Next Steps: PGE will continue to recruit participants with a target of 7,000 participants by end of 2017. 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 System.

[7] http://apps.puc.state.or.us/orders/2015ords/15-203.pdf

Energy Partner

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 pilot was capable of 11.5 MW in winter 2015-2016 and will likely have 14 MW available for summer 2016.

Status: Pilots & Evaluation

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

Salem Smart Power Residential Direct Load Control

Description: 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

Next Steps: PGE is working with EPRI on a new pilot program listed in the future initiatives section of this report.

Smart Thermostat Demand Response Pilot (Rush Hour Rewards)

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). To date, 1,517 customers are enrolled in the winter program, and as of April 30, we have more than 700 summer participants. The pilot will evaluate: (1) what tactics achieve program participation, (2) how much load customers are comfortable shedding during peak events, (3) attrition, and (4) program cost-effectiveness.

Status: Pilots & Evaluation

Next Steps: PGE is working closely with Nest and ETO to continue encouraging smart thermostat adoption and program enrollment. PGE hope to enroll 3,500 customers in the pilot program by spring 2018 and to achieve 2-3 MW of DR. If the pilot proves successful, PGE will evaluate expanding the program to other device manufacturers, other technologies, and other customer segments.

Section 6. Research & Development

Research and development necessarily implies a certain amount of fluidity in targeted research topics. Listed below are the Smart Grid-related Research, Development & Demonstration (RD&D) project ideas that are currently budgeted for 2016. Many projects leverage and expand upon existing or planned smart grid initiatives.

Table 7 – PGE RD&D Projects, 2016

Initiative	
Microgrid Reliability Real-time load modelling for Synchrophasor	
Description: The goal of this project is to better understand load models in order to advance protection of the next generation power transmission and distribution infrastructure. With assistance from the growing Phasor Measurement Unit (PMU) network at Oregon State University (OSU), a composite dynamic load model can be estimated in real time and provide useful insight into the design of micro-grid protection schemes. This will address challenges such as reverse flows, automatic reclosing, or delayed relay tripping; it will also yield insights for Real-time power flow and load composition estimation. Modelling will Leverage sparse distribution of sensors with a machine learning framework together with in-lab testing and model validation.	
Benefits: This project will provide PGE with insights about the benefits of deploying PMUs at the distribution level: Improved analysis of anomalies from modern, non-traditional loads, as well as synchronization between transmission and distribution level sensing.	*2016 Budget:* $ 25,000.00

Initiative	
EPRI Program P94: Energy Storage & Distributed Generation	
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. EPRI's energy storage and distributed generation technologies program evaluates storage 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.	
Benefits: Better understanding of technical and economic challenges related to the use of utility-scale storage and distributed generation; understanding of effects of storage on the power delivery network	*2016 Budget:* $ 91,000.00
PSU-PGE Smart House Design Competition	
Description: PSU-led, campus-wide competition to encourage broad look at solutions for smart homes. The interdisciplinary competition will create broad perspectives on solutions for grid/renewable friendly "smart" homes. Focus is on solutions for homes that have the ability to use and/or store renewable energy when over generation occurs as wind and solar generation approaches 50% in California and later in WECC. This "project" funds the prize money. Judging would come from PSU, PGE and other third parties.	
Benefits: Learnings on how building design & control can enable renewables integration and can aid in periods of over-generation.	*2016 Budget:* $ 6,000.00

<table>
<tr><th colspan="2">Initiative</th></tr>
<tr><td colspan="2">EPRI Program 174: Integration of Distributed Energy Resources</td></tr>
<tr><td colspan="2">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>2016 Budget:

$ 35,000.000</td></tr>
<tr><td colspan="2">SSPC Use Case Test & Validation</td></tr>
<tr><td colspan="2">Description:

The battery inverter system (BIS) at SSPC is a novel asset to PGE, and one of only a handful in the country. Because of this unique platform and the recent passage of House Bill 2193 requiring PGE to procure an additional 5 MWh of energy storage, it is important to continue to advance PGE’s learning about how to best operate the asset and value the services it provides. This project will further PGE’s experience with the capabilities of the SSPC BIS system and will help position PGE and its customers for success under HB2193, including:
1. Develop an algorithm to determine the BIS’ round trip efficiency
2. Test the volt/var use case
3. Test the adaptive conservation voltage reduction use case
4. Create and test a use case optimization routine</td></tr>
<tr><td>Benefits:

This project increases the value of the services SSPC provides to PGE customers as a grid-integrated asset by optimizing the operation between use cases based on economic value and system reliability. This could result in things like peak load reduction, frequency response, and energy savings.</td><td>2016 Budget:

$ 80,000.00</td></tr>
</table>

Initiative	
Develop Model to Assess DSG Program Target Capacity	
Description: The current financial model for the DSG program is simplistic and does not assess the need for incremental DSG units. This makes it difficult to understand the value of each additional DSG Megawatt on PGE's system. In order to plan for the growth and future of the program, a model must be developed that integrates with all of PGE's generating resources, load profiles and wholesale markets. PGE is using Energy and Environmental Economics, Inc. (E3) to develop resource adequacy needs assessments for the IRP group. This project would leverage the existing E3 model by retaining them to perform follow-on work. This new project would break out separately each capacity resource (like DSG) to analyze the optimal level of incremental capacity for specific resources (currently, the model just lumps DSG capacity in with all other capacity resources).	
Benefits: Developing a comprehensive model will help the DSG and IRP groups understand to what level to develop this program and how important non-emergency resources are to the program. This model will help accurately determine the growth targets for the DSG program.	*2016 Budget:* $ 30,000.00
Joule Bank System -- Bulk Thermal Storage	
Description: This is a continuation of a unique, proprietary project started in October 2014 on the design and early prototyping of the Joule Bank System, a new, flexible, highly efficient, residential heating and cooling system based on heat pumps and thermal storage. Extensive collaboration has evolved on this project to ensure arms-length, third-party assessment. Collaborating institutions include Harvey Mudd School of Engineering for thermodynamic assessment and modelling; Portland State University for initial prototype design and development. In 2015, PGE concluded theoretical and prototype development; in 2016 – it is anticipated that a "production" model will be tested under real-world conditions.	
Benefits: PGE estimates that 90% of peak demand can be eliminated by thermal storage & utility control. This study informs technology viability and demonstrated value.	*2016 Budget:* $ 35,000.00

Initiative	
Battery Backup Field Demonstration, PSU Collaboration	
Description: The purpose of this project is to demonstrate a distributed, scalable control and installation architecture that would allow for relatively fast deployment to enable an aggregated resource of hundreds of MWs. PGE proposes to build a "microgrid" consisting of systems installed at 2 to 4 fire stations, or on a smaller scale, e.g. a residential house, and aggregated to operate as a single system through DSG's GenOnSys control. The systems would provide backup power to the fire station or chosen site in the event of a power outage. The battery supply would allow power for up two days, and could be recharged in 5 hours with a portable generator to last another two days. Satellite fire stations have been considered because: 1) they are visible assets that would be desirable sites for backup power service, and 2) they are similar in electric characteristics to homes and/or to 240 volt service transformers (there are approximately 900,000 240 volt connection points in PGE's service area).	
Benefits: When a grid outage is not occurring, PGE would use the energy storage and power capacity of the aggregated systems to serve the needs of power operations, including peak management, reliability and resiliency, regulation, renewable firming , ramp control, energy shift, load flow control, and economic dispatch.	*2016 Budget:* $ 125,000.00
EPRI-Related Demonstration of Smart Water Heaters & EVSE	
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. This project involving smart water heaters - seeks to: 1) Validate technical approach of communication via CEA-2045 2) Develop first control strategies for 24x7x365 DR control 3) To extent possible, determine estimate of kW reduction achieved during periods of system peak demand 4) Obtain employee feedback about control approach and impact of control This project continues an earlier EPRI-related effort and can still call on EPRI resources as it evolves into the future.	
Benefits: At 100% customer adoption, Smart Water heaters could create 225 MW of peak demand reduction and 1500 MWh of load that PGE can dispatch to any part of the day -- all this at a cost that is less than 50% of the cost of a standard peaking plant.	*2016 Budget:* $ 40,000.00

Section 7. Future Smart Grid Investments

A. Opportunities for Next 5-10 Years

Electric Vehicle (EV) Charging Programs

With over 850 public EV charging stations in Oregon, PlugShare.com has reported that Oregon has the highest number of public stations per capita in the United States. PGE expects the number of EVs in Oregon to grow from about 6,300 today to over 100,000 by 2035. PGE is tracking the EV market and evaluating technologies that could serve as demand- or supply-side resources for PGE's resource portfolio.

Smart Charging (EV Demand Response)

Description: As ownership of EVs increases over time, DR-enabled vehicles or charging stations could prove to be a demand-side resource for the Company's IRP. PGE has conducted limited DR testing on customer and PGE's worksite charging stations.

Status: Planning Research & Demonstration

Next Steps: PGE is collaborating with EPRI in studying the interoperability of smart appliances. PGE is working to launch a demonstration project in 2016 to explore DR with EVs and residential charging stations. Approximately 35 EV drivers will participate in a centrally managed charging process that signals cars or charging stations to adjust demand in real-time to optimize resource and system utilization. Additionally, some participants will be on a TOU program to evaluate the smart (timed charging) aspects of their vehicle and/or a smart charger.

Other EV Programs

Description: Future RD&D/pilot projects may explore these concepts:

- **Preferential TOU rates:** If cost-effective, new rates for customers with registered EVs in our service territory might be eligible for reduced pricing to charge their vehicles in off-peak hours.
- **Vehicle to Home**: EVs to provide back-up power to residential homes through outlets or a service-panel connection.
- **Vehicle to Grid (V2G)**: EVs as a resource for ancillary services and renewables integration in PGE's IRP.
- **Second-Life Battery for Home or Grid**: utilizing car batteries after their primary life in homes and businesses as a resource for optimizing and shifting load. This is being explored as an option to fulfill the requirements of HB2193.

Status: Future Initiative

Next Steps: PGE is collaborating with vehicle and charging station manufacturers in consideration of developing future pilot programs.

Distribution Management System (DMS)

Description: DMS is foundational to a smart T&D infrastructure and is necessary to get the maximum value of DA. DMS manages distribution field hardware using real-time telemetry and automated-switching operations. The combination of a DMS and automated-switching devices creates the potential for a self-configuring network. The continuous feed of power-flow data allows a DMS to track dynamic loading (relative to maximum ratings) on all distribution assets to determine if alternative feeds are possible. Even without communication to automated switching devices in the field, this system can speed the determination of safe switch orders during an outage. In non-outage conditions, a DMS can identify feeders where phase imbalances exist and quantify the savings possible under various "what if" configuration changes, recommend seasonal switch changes to minimize energy loss and manage field hardware to enable Conservation Voltage Reduction benefits.

Status: Future Initiative

Next Steps: 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.

Synchrophasors on Distribution System

Description: Deployment of PMUs and PDCs on PGE's distribution system could result in enhanced situational awareness and more effective DA. PGE has deployed 5 PMUs on a feeder in Canby as a part of the SEGIS initiative. These PMUs primarily inform solar research, however they could inform a future deployment of synchrophasor technology on the distribution system.

Status: Future Initiative

Next Steps: PGE anticipates a potentially undergoing a full evaluation of the technology and the opportunities for synchrophasors on its distribution system in the 2019-2020 timeframe.

PGE is actively exploring how customer programs (i.e. microgrids or home battery back-up) may satisfy some of the 5 MWh mandate of HB2193.

Microgrids

Description: Over the past few years we've had a number of customers from various industries (hospitals, universities, emergency response facilities) approach us looking for information on how PGE can help them meet their backup power requirements and resiliency needs. PGE is working on a microgrid market assessment to determine service territory-wide potential for future microgrid projects. Microgrids are a discrete energy system that employ a variety of distributed energy sources such as diesel generators, on-site generation, batteries, etc. and loads capable of operating in parallel with, or independently from PGE's grid.

Status: Research

Next Steps: PGE is evaluating opportunities for a potential microgrid demonstration project in 2017-2018. Additionally, PGE, ETO, Commission staff, and a commercial customer will be working together on developing a pilot microgrid program design during Rocky Mountain Institute's eLab Accelerator: A Bootcamp for Electricity Innovation program.

Customer Battery Back-Up System

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 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: If the demonstration proves successful 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.

Bulk Thermal Storage

Description: PGE is continuing to collaborate with PSU to test 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 pumps but has them use the thermal storage tank (instead of outside air) to meet the customer demand. Previous modeling work demonstrates substantial energy savings while achieving a significant reduction in on-peak load.

Status: Research

Next Steps: If the prototype proves viable, PGE would 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.

Smart Water Heaters

Description: PGE has launched a small "smart" water heater demand response demonstration project and will use this experience to guide a 600-point regional pilot with BPA in 2017. The present demonstration involves fourteen residential customers who have installed a communications module that "plugs" into their water heater (no electrician is required for the installation). Control events are being implemented on a daily basis. The communication module uses hybrid communications: 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.

Status: Planning Pilot

Next Steps: PGE anticipates two outcomes from this demo. In the short run, this will influence the design of a late-2017, or 2018 water heater pilot. Second, 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 in 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 demand response.

Strategic Deployment of Distributed Energy Resources (DERs)

Description: 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.

Status: Future Initiative

Next Steps: PGE plans to assess how DERs could be utilized for T&D risk reduction in 2017-2018.

Prepaid Metering

Description: 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.

Status: Future Initiative

Next Steps: 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 on pilot design.

Section 8. Related Activities

A. 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.

B. Information Technology

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 potentially be compromised by cyberattacks, which could undermine reliability. PGE has been actively revamping internal networks to provide "secure-by-default infrastructure zones," which are positioned 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 in the way smart grid interoperability demand, with a consistent architecture, technology footprint and a management toolset that PGE can use to quickly and repeatedly respond to new vulnerabilities or threats. 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 is adopting 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.

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

- Reposition CCS in secure-by-default infrastructure zones
- Extend virtualization and virtualization security benefits to CCS
- Improve posture-assessment capability for remote and physical accesses
- Implement CIP compliance for network systems and substation remote access Substation Remote Access was installed to ensure secure data gathering & access to substation IEDs in compliance with NERC CIP standards
- Mitigate the impact of new NERC requirements (for example, CIPv5) to utility systems
- 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.

Data Privacy

The Smart Grid encourages expanded use of data, which will require deeper coordination with customers in order to consider their individual privacy concerns. PGE’s IT policy requires every system to classify the data within and to adhere to consistent handling requirements for that data. For example, data classified as confidential or restricted must be encrypted and follow proper destruction procedures when no longer needed. [8]

PGE is always considering projects that will allow customers more detailed access and control over their billing, usage or other data. Any time activities such as these are pursued, data-privacy issues related to customer data will be addressed.

Finally, as part of PGE’s ongoing Information Security Program, all future Smart Grid initiatives involving technology or customer information will require rigorous security testing and validation to ensure these projects are ready to deploy in a safe and secure manner

C. Strategic Asset Management

T&D Strategic Asset Management (SAM) is a program launched in PGE’s Customer Service, Transmission and Distribution group in 2013. The program supports risk management activities in the T&D asset base by identifying high risk assets and asset systems, evaluating the relative merit of different risk reduction options, and advocating for risk reduction investments that demonstrate the most value to customers and PGE. Primary deliverables produced by SAM include economic life models for significant T&D asset classes and asset systems; long-range strategic plans for risk reduction in the asset base; and capital investment recommendations to support plan execution. The primary risk factors evaluated by SAM include threats to reliability (aging assets, assets in poor condition, assets with very high customer counts or loading), safety and environmental threats, and threats to effective cost management.

In 2014, SAM assessed PGE’s most critical substation asset classes; a sizeable multi-year substation risk reduction program is in development now. In 2015, SAM modelled individual distribution asset classes to identify high risk assets and feeders. SAM uses these base models to evaluate risk which aids in prioritizing the deployment of Smart Grid technologies across the distribution system, and ascertain where such technologies make economic sense for customers and PGE given their costs and risk reduction benefits (e.g., shortening average outage durations).

[8] Confidential or restricted information includes social security number, driver’s license number, credit card numbers or financial information.

D. 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.

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

Appendix 1. Summary of All Smart Grid Initiatives

Table 8 – Summary of All Smart Grid Initiatives

Initiative	Status	Page
Advanced Metering Infrastructure	Complete	21
Automated Generation Control	Complete	22
Bulk Thermal Storage	Research	46
Communications Upgrades	Active Deployment	21
Conservation Voltage Reduction	Pilots & Evaluation	31
Customer Battery Back-Up System	Research	50
Customer Information System	Planned Deployment	27
Demand Response: Energy Partner Pilot	Pilots & Evaluation	41
Demand Response: Firm Load Reduction (C&I)	Active Deployment	39
Demand Response: Residential Direct Load Control	Complete	41
Demand Response: Smart Thermostat Pilot	Pilots & Evaluation	42
Demand Response: Smart Water Heaters	Planning Pilot	51
Dispatchable Standby Generation (DSG)	Active Deployment	38
Distribution Automation	Pilots & Evaluation	30
Distribution Management System (DMS)	Future Initiative	48
Distribution Temperature Sensing	Limited Deployment	35
EMS State Estimator	Limited Deployment	22
Energy Expert	Active Deployment	25
Energy Management System	Complete	22
Energy Storage	Planning	29
Energy Tracker	Active Deployment	24
EV: Preferential TOU rates	Future Initiative	48

Initiative	Status	Page
EV: Second-life battery for home or grid	Future Initiative	48
EV: Smart Charging (EV Demand Response)	Planning Pilot	48
EV: Vehicle to Grid	Future Initiative	48
EV: Vehicle to Home	Future Initiative	48
Fault Detection (Distribution)	Pilots & Evaluation	33
Geographical Information System	Complete	26
Meter Data Management System	Planned Deployment	27
Microgrid	Research	50
Outage Management System	Complete	26
Prepaid Metering	Future Initiative	52
Pricing Program: Critical Peak Pricing	Complete	39
Pricing Program: Flex Pricing Research Pilot	Pilots & Evaluation	40
Pricing Program: Time-of-Day Pricing	Active Deployment	38
Pricing Program: Time-of-Use Pricing	Active Deployment	38
Real-time Contingency Analysis	Limited Deployment	22
Remedial Action Schemes/Special Protection Schemes	Limited Deployment	35
Research & Development	Research	43
Remote Service Detection (Outage Confirmation)	Complete	37
Salem Smart Power Project	Complete	32
SCADA	Active Deployment	28
Smart Inverters	Research	90
Solar Energy Grid Integration Systems (SEGIS)	Complete	37
Strategic Deployment of Distributed Energy Resources	Future Initiative	52
Substation Automation	Active Deployment	29

Initiative	Status	Page
Substation Remote Access Server	Active Deployment	28
Synchrophasor Deployment (Distribution System)	Future Initiative	49
Synchrophasor Deployment (Transmission System)	Pilots & Evaluation	34
T&D Analytics	Pilots & Evaluation	23
T&D Asset Monitoring	Active Deployment	36
Travelling Wave Fault Location Protective Relays	Limited Deployment	36
Voltage Disturbance Detection (i-Grid)	Limited Deployment	35

Appendix 2. Smart Grid Metrics

OPUC Condition: Continue the stakeholder process for researching and including additional reliability and operational metrics in its next smart grid report as well as to improve existing metrics.

PGE held a workshop with Stakeholders on February 9, 2016 to kick off a discussion on metrics. Attendees included OPUC Staff, ETO, and CUB. Changes to metrics discussed in that workshop have been included in this section.

Table 9 – Asset Optimization Metrics

Metric	2012	2013	2014	2015
% Substations with SCADA	70%	70%	74%	77%
% Critical Transformers w/ DGA	68%	68%	68%	68%
Efficiencies realized through CVR (MWh)	-	356	768	-[9]
System Risk Holding ($)	*Potential Future metric: Not yet capturing*			
System Risk Mitigated ($)	*Potential Future metric: Not yet capturing*			

Table 10 – Reliability Metrics, Corporate Summary

Metric		2012	2013	2014	2015	3-yr Avg.
Including Major Event Days[10]	SAIDI	136	205	245	175	208
	SAIFI	0.72	0.57	1.2	0.78	0.85
	MAIFI	1.1	0.9	1.3	1.2	1.1
	CAIDI	189	360	204	222	262
Excluding Major Event Days	SAIDI	72	61	94	75	77
	SAIFI	0.55	0.45	0.7	0.48	0.54
	MAIFI	1.1	0.9	1.3	1.2	1.1
	CAIDI	131	138	135	156	143
ASAI, CEMI, & CELID		*Potential Future metric: Not yet capturing*				

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

[10] 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 11 – Reliability Metrics by Region, Eastern

Metric		2012	2013	2014	2015	3-yr Avg.
Including Major Event Days	SAIDI	214	119	279	237	212
	SAIFI	0.94	0.69	1.45	1.03	1.06
	MAIFI	1.64	1.32	1.67	1.58	1.52
	CAIDI	227	172	193	230	198
Excluding Major Event Days	SAIDI	86	75	115	76	89
	SAIFI	0.64	0.57	0.83	0.55	0.65
	MAIFI	1.64	1.32	1.67	1.58	1.52
	CAIDI	134	133	139	139	137

Table 12 – Reliability Metrics by Region, Southern

Metric		2012	2013	2014	2015	3-yr Avg.
Including Major Event Days	SAIDI	108	97	224	155	159
	SAIFI	0.61	0.45	0.82	0.70	.66
	MAIFI	0.6	0.40	0.9	0.9	.7
	CAIDI	177	216	273	223	237
Excluding Major Event Days	SAIDI	78	47	67	91	68
	SAIFI	0.53	0.30	0.40	0.51	0.40
	MAIFI	0.6	0.40	0.9	0.9	0.7
	CAIDI	147	157	168	178	168

Table 13 – Reliability Metrics by Region, Western

Metric		2012	2013	2014	2015	3-yr Avg.
Including Major Event Days	SAIDI	86	400	208	97	235
	SAIFI	0.60	0.46	1.08	0.49	0.68
	MAIFI	0.7	0.70	1.1	0.74	0.85
	CAIDI	143	870	193	200	421
Excluding Major Event Days	SAIDI	61	50	78	64	64
	SAIFI	0.51	0.36	0.67	0.37	0.47
	MAIFI	0.7	0.70	1.1	0.74	0.85
	CAIDI	120	139	116	178	144

Table 14 – Energy Storage Metrics

Metric	2012	2013	2014	2015
Available Storage Capacity (MW)	5	5	5	5
Available Storage Energy (MWh)	1.25	1.25	1.25	1.25
# of Energy Storage Locations	1	1	1	1

Table 15 – Electric Vehicle Metrics

Metric	2012	2013	2014	2015
Number of Electric Vehicles in Service Territory[11]	1,600	4,033	5,500	6,300
Number of EV Charging Stations in Service Territory[12]	729	866	1,053	1,233

[11] Estimated based on ODOT estimates of EVs in Oregon with about 80% in PGE service area
[12] Estimated based on Alternative Fuels Data Center- USDOE, Ecotality, Plugshare (note: not all sources agree)

Table 16 – Customer Engagement Metrics

Metric		2012	2013	2014	2015
Total # Customers that have utilized Energy Tracker	Residential	79,702	123,508	165,004	201,375
	Commercial	728	1,440	2,462	3,388
	Total	80,430	124,948	167,466	204,763
Energy Tracker Realized Savings[13]		3%			
# Customer Utilizing Energy Expert		40	101	97	105
# of Customer Accounts of TOU Rate Schedule	Residential	2,287	2,313	2,303	2,305
	Commercial	1,630	1,672	1,794	1,785
	Industrial	132	131	129	120
	Total	4,049	4,116	4,226	4,210
# Customers participating in DSG		29	33	34	35
Dispatchable capacity of DSG (MW)		79.4	83.4	94.0	106.8
Capacity of customer-owned renewable (MW)[14]		28.6	35.8	44.5	54.2
Number of customer programs[15]		6	6	6	6

[13] Energy Tracker savings data is based on program evaluation in 2013

[14] 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.

[15] 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 17 –Demand Response Metrics[16]

Metric		**2012**	**2013**	**2014**	**2015**
# Customers participating in DR	Residential[17]	596	552	0	177
	Business	1	3	38	57
	Total	**597**	**555**	**38**	**234**
Available capacity of DR (MW)	Residential	0.2	0.1	0.0	0.2
	Business	16.0	16.3	24.6	14.1
	Total	**16.2**	**16.3**	**24.6**	**14.3**
Summer Peak (MW)		3,597	3,527	3,646	3,914
Available capacity of DR (% of summer system peak)		0.45%	0.46%	0.67%	0.36%
Winter Peak (MW)		3,426	3,869	3,866	3,255
Available capacity of DR (% of winter system peak)		0.47%	0.42%	0.64%	0.44%

[16] 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.
[17] 2012-2013 Residential DR programs include the Critical Peak Pricing Pilot. 2015 includes the Nest Pilot and Smart Water Heater Demonstration

Table 18 – Customer Engagement Metrics
(% Participation in Each Program Type by Segment, 2015)

Segment	Residential	Business
% Participation in each program type		
Avg. # of Retail Customers[18]	742,467	106,057
Energy Information Services	27.1%	3.3%
Demand Response	0.0%	0.1%
Pricing Program	0.3%	1.8%
Distributed Generation	0.85%	0.57%

Table 19 – Total Number of Smart Meters Deployed[19]
(By Year, Customer Type)

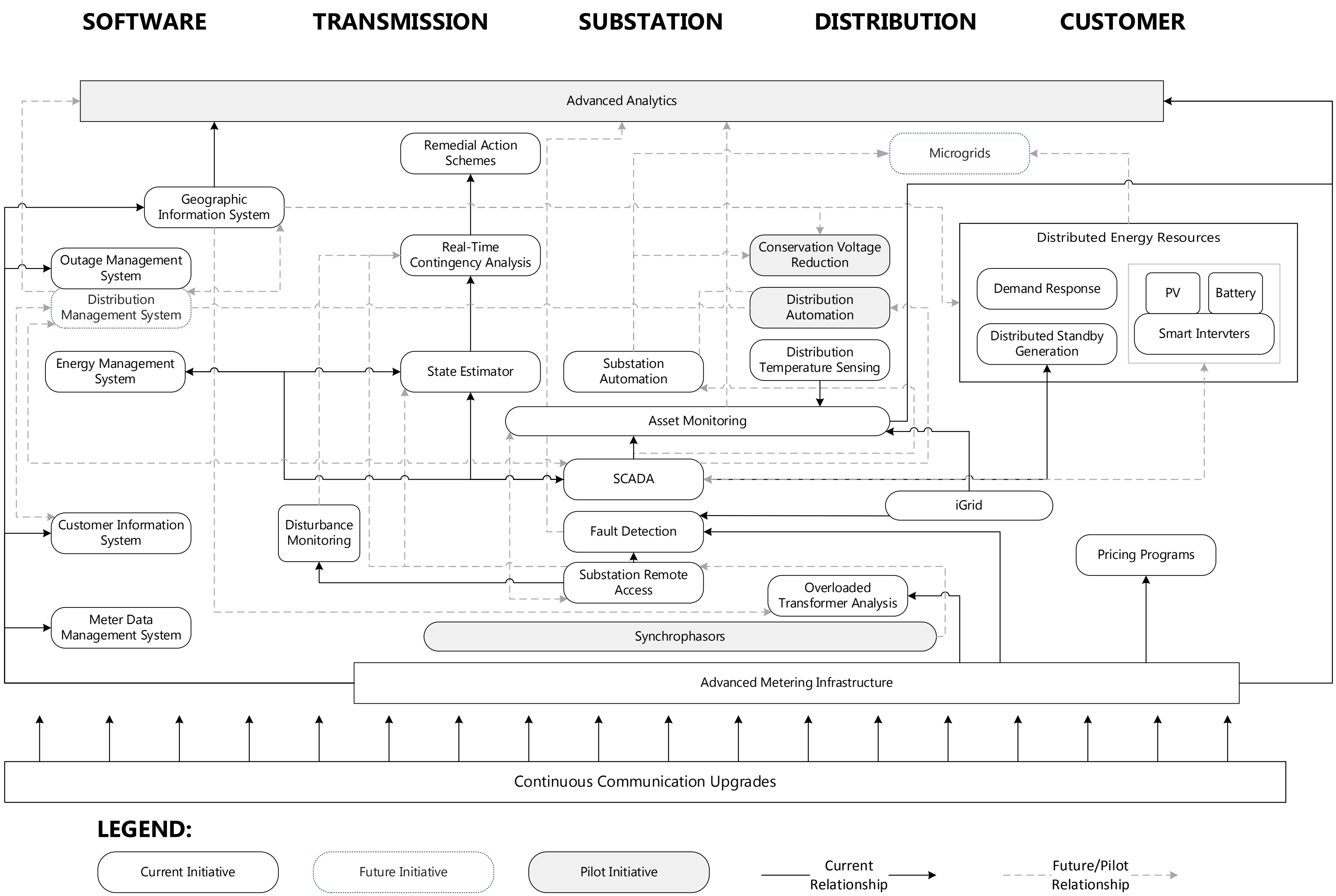
Customer Type	2012	2013	2014	2015
Residential	744,392	752,668	760,932	756,063
Commercial	113,149	114,400	115,197	102,228
Industrial	4,790	4,751	4,707	3,951
Total	**862,331**	**871,819**	**880,836**	**862,242**

Table 20 – AMI Complaints and Opt Outs
(By Year, Customer Type)

Metric	2012	2013	2014	2015
# Customer Complaints about AMI	133	118	136	94
Cumulative # Customers Choosing No AMI	4	9	15	22

[18] PGE 2015 Annual Report: http://investors.portlandgeneral.com/annuals-proxies.cfm
[19] 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).

Appendix 3. Visualization of T&D Smart Grid Initiatives



Appendix 4. Demand Response Cost-Effectiveness Process

OPUC Condition: Provide the results of the dynamic pricing stakeholder process for developing a cost-effective methodology, the exploration of cycling load, tracking of customer fatigue, and the exploration of enabling technologies.

In the summer of 2015, PGE filed a request for deferred accounting for the expenses associated with the smart thermostat DR pilot and the Flex pricing pilot (Docket No. UM 1708). The deferral was approved via Commission Order No. 15-203,[20] which directed PGE to work with stakeholders to develop a cost-effectiveness methodology for demand response:

> ***Development of Cost Effectiveness Methodology Best Practices***
>
> *As evidenced by PGE's use of de-rate; the utility and stakeholders will need to explore the development of a cost effectiveness methodology for demand response programs. Demand response can offer many different energy and capacity products. Although demand response is a demand side asset like energy efficiency, it functions more like a supply side dispatchable resource. Therefore it is important that PGE, the Commission and stakeholders develop a cost effectiveness methodology for demand response that is particular to the capabilities and products of this resource. Staff recommends that PGE lead a stakeholder workgroup to develop a cost effectiveness methodology that is unique to demand response. The pilot projects approved in this docket and others will help supply the necessary data and learnings needed to begin crafting a cost effectiveness methodology for demand response.*
>
> *Source: UM 1708, Order No. 15-203, p. 14.*

In the fall of 2015, PGE solicited proposals for a firm to develop a whitepaper on a proposed methodology for assessing the cost-effectiveness of smart grid investments (with a focus on Demand Response) in Oregon and to evaluate cost-effectiveness of the Energy Partner pilot. In January, 2016, PGE contracted with Navigant to provide those services.

PGE and Navigant have proposed a model that utilizes cash flow analysis to produce benefit-cost test ratios and net present value based on:

1. California Public Utilities Commission, 2010 Demand Response Cost Effectiveness Protocols
2. Industry best practices
3. Cost-effectiveness methodology used by Energy Trust of Oregon for energy efficiency

[20] http://apps.puc.state.or.us/orders/2015ords/15-203.pdf

PGE held a stakeholder workshop on February 11th, 2016 to discuss which tests should be utilized for DR cost effectiveness and which inputs to model and how they'd be quantified. Key points of consideration from the meeting are outlined below:

- Valuation variables (avoided costs, value of reliability)
- Shared benefits w/ ETO
- Quantification of environmental benefits
- Quantification of distribution benefits
- Potential for utilizing model beyond DR and to expand to all smart grid cost effectiveness
- Tracking of customer fatigue,

Navigant incorporated feedback received at the stakeholder meeting, and PGE filed a Whitepaper titled *A Proposed Cost-Effectiveness Approach for Demand Response* with the OPUC on April 28, 2016.

As of the writing of this report, PGE has not received formal feedback from OPUC Staff.

PGE has utilized this methodology for evaluating cost-effectiveness of the Energy Partner pilot. As this methodology continues to be utilized in program evaluation, PGE anticipates that Staff may open up additional dialogue for some of our assumptions going forward.

Appendix 5. Smart Thermostat DR: Preliminary Results

OPUC Condition: Include any preliminary results and findings from its dynamic pricing pilot & DLC pilot.

PGE successfully deployed the Nest Rush Hour Rewards pilot in the winter of 2015-2016, as the first utility to offer a winter DR program with Nest. 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).

To date, the Company has recruited 1,517 customers and called 8 events (estimated 0.3 MW capacity). Initial customer feedback has been positive, and we are working closely with Nest to continue growing program enrollments.

The pilot hopes to enroll 3,500 customers and be able to achieve a 2-3 MW demand reduction each event.

At the conclusion of the pilot program, the Company will evaluate:

- cost effectiveness of the bring-your-own-device program type
- customer satisfaction and attrition
- what tactics are successful in getting the install base to join
- what are customers comfortable contributing during peak events for the incentive given

Appendix 6. Flex Pricing Program: Preliminary Results

OPUC Condition: Include any preliminary results and findings from its dynamic pricing pilot & DLC pilot.

The Flex pricing pilot will test 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 for the Flex pricing pilot launched in February, 2016. To date, over 1,500 customers enrolled with a target of 7,000 participants by end of 2017.

As of the writing of this report, no events have been called nor has any analysis been conducted on load shifting associated with program enrollment.

PGE will continue to recruit participants with a target of 7,000 participants by end of 2017. The pilot will run through 2018. At the conclusion of the pilot program, the Company will evaluate:

- cost effectiveness of each pricing program tested and behavioral demand response
- customer satisfaction and attrition of each program type
- what education and outreach tactics are successful in getting customers to enroll and to understand pricing programs

PGE plans to identify one or more of the most effective pricing program options in order to scale a program for all customers in 2019 after the deployment of the new Customer Information System.

Appendix 7. Synchrophasor Scope & Timeline

OPUC Condition: Include Project-X's scope & timeline as well as the projected costs & benefits.

Introduction

The X-Phase Project is the integration of Phasor Measurement Units (PMUs) and their parent device Phasor Data Concentrators (PDC) on PGE’s Transmission system to enhance situational awareness affecting grid reliability, efficiency, and performance. This will transform existing means of post-event analysis and proactive contingency avoidance. Time-synchronized measurements, known as synchrophasors, enable operators to visualize system states in real time and optimize solutions for area control, protection, and monitoring.

Modern power system monitoring techniques utilize data from remote terminal units (RTUs), protective relays, and transducers to provide information to system operators. This information is vital for power system operations under both normal and contingency scenarios. However, the mechanism used to retrieve data from field devices is asynchronous and relatively slow. Asynchronous data cannot provide accurate angle difference information between two or more nodes on the network. Additionally, the low volume of retrieved data provides insufficient detail to capture many short-duration grid disturbances.

PMU data samples are rapid, accurate, and temporally aligned via GPS time-stamps. The sampling rate for a PMU is between 30 and 60 samples per second, as opposed to existing SCADA sampling rates of 1 sample per 5 seconds. This technology is used to provide high-speed, synchronous, real-time, vector data that is not available from legacy SCADA systems. Data content upgrades are increasingly important with the evolution of Smart Grid applications, whose functions require heightened informational detail.

The long-term goal of the X-Phase Project is to develop a wide-area network of PMUs encompassing all PGE Transmission Substations, which will be developed through a multi-year, multi-phase roll out. PMUs are a standard option in most protective relaying equipment currently installed on the PGE network. A secondary goal of the X-Phase Project is to activate PMU functionality through firmware upgrades to existing equipment.

The phased project will initially establish a base wide-area network with six critical substations, including: Bethel, Gresham, West Portland, Rivergate, and Trojan. Additionally, the Rosemont substation was commissioned using 2014 R&D funding. This initial network serves as the foundation for further substation upgrades to expand synchrophasor capabilities and geographical reach.

In addition to the value added to protection, control and monitoring, the X-Phase Project will allow PGE to be a more efficient and reliable player in the Western Energy Markets. The anticipated growth of variable renewable generation, such as solar and wind power, in the West has raised concerns about how system operators will maintain balance between electricity production and demand in the Western Interconnection and especially in its smaller balancing authority areas. Electric utilities are therefore considering the adoption of a large-scale energy imbalance market to address fluctuations in electricity generation and load. In an energy imbalance market, the variability of electricity generation and load is aggregated over multiple balancing authority areas and utility territories.

Use Cases

- **Generator Model Validation:** Generator models are used for contingency analysis and equipment malfunction forecasting. The existing model validation process requires offline testing, which incurs costs associated with generator downtime and risk of system instability. Synchrophasors will allow testing and model validation while the generator is in service, using test pulse signals routinely commissioned by BPA.

- **Post Event Analysis for PRC-002:** NERC mandate PRC-002-2 for post event analysis requires PGE to store a minimum 10 days of data at 30 samples/second fidelity for priority substations. The existing post event analysis process is based on data that is sampled every 5 seconds. With the heightened sampling rates provided by synchrophasors, engineers can gain visibility and insight into events that are not shown with existing sampling rates. Also, previously unknown signatures of developing events can be identified and characterized by analytical platforms, thereby expanding contingency prevention capabilities.

- **Protection AC Signal Verification for PRC-005:** NERC protection system maintenance requirements include verifying AC signals (current and voltage) to relays. The tests are typically time-consuming as technicians are sent to the site to search for an independent source of verification. Remote access to real time data would allow the Testing & Energization Engineers to conduct verification more efficiently from the office.

- **Participation in the Energy Imbalance Market (EIM):** PacifiCorp has developed an inter-area power trading platform based on synchrophasor data. Synchrophasors will allow PGE to participate in the EIM and gain flexibility in power supply and pricing. This results in improved reliability and a potential new revenue stream, expected to save PGE between $2 Million and $7 Million per year. In the proposed Western energy imbalance market, balancing authority areas pool their variable and conventional generation resources to improve operational efficiency over a wider area. This sub-hourly, real-time energy market provides centralized, automated, region-wide generation dispatch. Expanding the temporal and geographic footprint of the total balancing authority area will enable market-based moderation of the variability in renewable generation resources and electricity demand.

- **Black-start Synchronization:** Reenergizing stations post transmission outage requires black-start synchronization. PGE currently has limited deployment of black-start synchronizing equipment. Synchrophasors will expand black-start capabilities, provide more accurate synchronization, and allow a higher degree of connectivity with outside territories. PGE also has known interconnection challenges with PacifiCorp and other critical interties. With two asynchronous systems merging during interconnection, an increasing phase angle difference can become a serious problem when the deviation grows large enough to cause arcing or out-of-step conditions. This is a potential safety concern, specifically at PGE's Hayden Island interconnection. Synchrophasors would accurately phase and provide critical measurements to safely switch between disparate systems. This will improve reliability and potentially reduce black start costs.

- **Participation in the Western Interconnection Synchrophasor Program (WISP):** BPA is leading an inter-area monitoring program, where utilities and balancing authorities have visibility on events in adjacent service areas that may affect their system. Synchrophasors will provide insight on interactions of the broader transmission system, allowing PGE to participate in WISP and gain reliability advantages.

Scope of Work

This project has a base data storage requirement of 10 TB. It also requires the installation of PDCs in each substation to process phasor data from PMUs at each bus voltage level and communications from transmission substations to the Remote Access Server (3WTC 3rd Floor). Data will be stored and processed through visualization software. Included in this project are the following:

- The addition of 10 TB data storage in the Corporate Network, which will store up to three years of data for expanded capacity up to 202 PMUs. This three year requirement for storing event data aligns with NERC/WECC audit schedules.
- Visualization software and limited storage in the Energy Network to enable real-time analysis applications for System Operators.
- Substations included in scope: Bethel, Gresham, Rivergate, Trojan, West Portland
- Installation of (5) PDCs, one in each X-Phase transmission substation.
- T1-Lines (~1.5Mbps) from substations to remote access server. (*Not part of this funding request already planned* to be implemented by Communications Engineering.

Table 21 – Synchrophasor Deployment Cost Estimates

Item	Estimated Cost
Bethel Substation	$ 15,183.00
Gresham Substation	$ 15,103.00
Rivergate Substation	$ 15,089.00
Trojan Substation	$ 15,305.00
West Portland Substation	$ 37,516.00
(IT) Software O&M	$ 29,673.00
(IT) Software Capital	$ 290,845.00
Total	**$ 418,714.00**

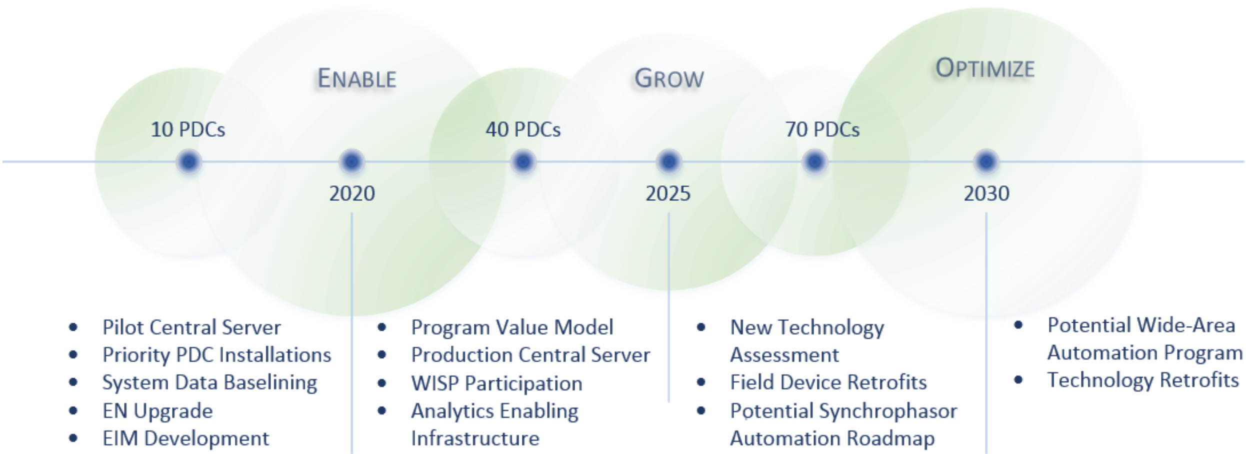
Project Status

In 2015, one substation synchrophasor and a test server in the Energy Network were deployed to observe the effects of data transport and storage volumes. Because of data storage capacity limitations on the Energy Network, IT infrastructure design was altered to include separate servers for real-time and archival data. Full IT infrastructure installation was delayed until 2016, due to data access issues from faulty monitoring equipment during the test phase of the real-time data server. These issues were resolved in Q4 of 2015. The test server for archival data is expected to be complete by Q3 of 2016, and installation of the production-level real-time and archival servers is planned for Q4 of 2016. Four substation synchrophasor installations are also planned for 2016. The total project cost for IT infrastructure is $320,518 and for substation equipment is $98,196.

Reports from early adopters indicate unanticipated O&M expenditures for maintaining and operating large synchrophasor deployments. Therefore, PGE will utilize the first two years after completion of the central server for system baselining and business model development. Benefit/cost models are not well established for synchrophasor use cases, and must be carefully considered before pursuing motivated investment in the program. During the baselining period, PGE will track the outcomes of preliminary development for targeted use cases to establish cost/benefit outcomes and inform future investment strategy. Full-scale deployment of synchrophasor capabilities will require reconstruction and expansion of the IT Energy Network for advanced real-time analytics.

Presently, standards and applications for synchrophasor data are in development stages at a national level. T&D Planning is actively participating in the NERC Synchronized Measurement Subcommittee (SMS) Task Force to assess future standards, applications, and strategies for synchrophasors. These efforts will result in a NERC planning guideline for synchrophasor networks. Development of the NERC synchrophasor planning guideline will coincide with the baselining phase of the PGE synchrophasor network.

The buildout timeline for the synchrophasor program will depend on network upgrades necessary to facilitate large volumes of data flow and storage; such as communications infrastructure, software developments, and network reconfiguration. The timeline for full deployment will not be well-established until baselining results and technical standards are known. The following schedule covers a general fifteen-year program planning timeline, which is non-committal and subject to change.



Appendix 8. Salem Smart Power Center Report

OPUC Condition: Work with Staff & other SSPP stakeholders to produce a comprehensive report with subsequent, recurring updates as work continues on the SSPP.

Background

PGE has implemented the Salem Smart Power Project (SSPP) delivering five assets that were funded as part of the US DOE's 5-year, $178 million Pacific NW Smart Grid Demonstration Project. The SSPP effort expended $25 million of which 50% of the cost was covered by US DOE stimulus funding beginning in 2010. The remaining 50% was 50-50 cost shared between PGE and its principal vendors: Enerdel, Eaton and Alstom. PGE's overall cost was $6.5 million and yielded the Salem Smart Power Center which showcases a 5 MW, 1.25 MW-hr lithium ion battery-inverter system (BIS). The facility is located at PGE's Oxford substation in Salem Oregon and is grid-tied via the 12.4 kV Rural Feeder line. PGE served as a contractor to Battelle which in turn was the primary to the US DOE in its role as operator of the Pacific NW National Laboratory.

This project has generated much interest locally, regionally and nationally. In response and as a matter of good stewardship – PGE staff have authored a number of reports to document progress, topical highlights and summary overviews. One of these reports was an introspective project "lessons learned review" performed at the request of PGE executive management. The report provides a programmatic review of the project, successes and difficulties as well as the unvarnished resolutions devised to meet contingencies, unexpected or not.

PGE's Salem Smart Power Project delivered five contractually-required assets: (1) Residential demand response (DR); (2) Commercial DR; (3) Commercial dispatchable standby generation (DSG) – Grid Connected; (4) Battery Storage – Grid Connected; (5) Distributed Switching and Commercial Microgrid. These assets were integrated via PGE's Smart Power Platform. They were declared as used and useful capitalized utility assets as of August 30, 2013. From that time thru project completion, all five of PGE's assets have been demonstrated to respond to the Transactive incentive signal (TIS). Of the five assets, routine, automated response to the transactive incentive signal was provided by the SSPP Battery Inverter system while grid connected.[21]

[21] For more detail on the types of assets that are responsive to transactive control see: https://www.bpa.gov/energy/n/Utilities_Sharing_EE/Utility_Summit/Workshop2013/SmartGridinthePNW.pdf

Project Development & Administration Lessons Learned

1. **Thoroughly vet vendors' capabilities and financial standing.** Smart grid technology is a growing industry, full of emerging companies. Making sure these companies are well-capitalized will help ensure the financial success of future projects.
2. **Leverage outside resources to reduce risk.** ARRA funding helped make the SSPP possible. Outside financial resource reduced the amount of financial risk for PGE during project startup. Similar outside resources could be crucial for future projects based on emerging technologies.
3. **Assemble a strong, adaptable engineering and project management team**. The multidisciplinary PGE team successfully managed the SSPP through many different challenges. The PGE team not only worked on the project's managerial and technical aspects, but also on internal and external communications. Future projects will benefit from similar multidisciplinary approaches.
4. **Do lots of testing**. With the potential to impact both commercial and residential customers, the SSPP involved considerable performance testing and documentation to ensure the new battery-invertor system and other project elements would be robust and reliable, and provide ongoing positive benefits to PGE customers. Future efforts should emulate this testing approach.
5. **Take plenty of precautions**. Salem emergency responders, such as fire departments, were trained and knew exactly what was in the Salem Smart Power Center. Extraordinary safety and fire detection/suppression systems were included to assure the new systems acceptability to the local community, and as a functioning feature of PGE's power grid. Community and power grid safety should be a benchmark for future efforts.
6. **Understand the impacts of new role for PGE**. PGE entered into an arrangement to serve in a contractor role for the SSPP. The role of contractor with fixed project deadlines and unfamiliar financial procedures were counter to normal administrative and management practices in the electrical utility industry. The SSPP represented a highly valuable education for PGE for working in similar environments in the future.

Transition and Potential Future Uses of Delivered Assets

The overall Pacific NW Smart Grid Demonstration was completed by close of January 2015. PGE and all sub-contract recipients were directed by Battelle and the US DOE to complete a series of project close out processes. This paper discusses PGE's responses to this guidance with special focus on the potential or likely future uses of the installed physical assets. As PGE's developed assets were subsidized by substantial federal funds, PGE would like to be clear about its intentions for continued and planful use of these assets in a manner that is consistent with the original purpose of the Pacific NW Smart Grid Demonstration.[22]

Pacific NW Smart Grid Regional Demonstration Project

The primary objectives of the Pacific Northwest Smart Grid Demonstration project are to:

- Create the foundation of a sustainable regional smart grid that continues to grow following the completion of this demonstration project.
- Develop and validate an interoperable communication and control infrastructure using incentive signals to: coordinate a broad range of customer and utility assets, including demand response, distributed generation and storage, and distribution automation; engage multiple types of assets across a broad, five-state region; and reach from generation through customer delivery.
- Measure and validate smart grid costs and benefits for customers, utilities, regulators, and the nation, thereby laying the foundation of business cases for future smart grid investments.
- Contribute to the development of standards and transactive control methodologies for a secure, scalable, interoperable smart grid for regulated and non-regulated utility environments across the nation.
- Apply smart grid capabilities to support the integration of a rapidly expanding portfolio of renewable resources in the region.

U.S. Department of Energy

At the national level, the U.S. Department of Energy (US DOE) has elaborated its vision for the evolution of energy storage capabilities as part of the U. S. electrical grid. The three goals below are quoted directly from its 2013 assessment summary report on the state of the technology and its uses.[23]

1. Energy storage should be a broadly deployable asset for enhancing renewable penetration – specifically to enable storage deployment at high levels of new renewable generation.

2. Energy storage should be available to industry and regulators as an effective option to resolve issues of grid resiliency and reliability.

[22] The SSPP assets in this paper are physical in nature as opposed virtual, i.e., derived from software; from the very outset of the project software was not considered a tangible asset and thus not included in the auditable project equipment inventory.

[23] See: U.S. Department of Energy, December 2013, *Grid Energy Storage*, 67 pages; Available at: http://energy.gov/sites/prod/files/2013/12/f5/Grid%20Energy%20Storage%20December%202013.pdf

3. Energy storage should be a well-accepted contributor to realization of smart-grid benefits – specifically enabling confident deployment of electric transportation and optimal utilization of demand-side assets.

Responding to a Transactive Energy Signal

SSPP assets have demonstrated responsiveness to transactive control as well as the ability to fully island as a microgrid in collaboration with three extant PGE dispatchable standby generator (DSG) partner sites. Transactive control has ceased for all participants as of early September 2014. Additional use and valuation cases have been identified of which five have been demonstrated to date. Recent demonstrations include short-term, fast up and down frequency support and using the battery plus solar PV signal from nearby Kettle Brands to firm and shape the feeder load.

Governance for Activities Housed at the Salem Smart Power Center (SSPC)

Due to the novel and unique nature of the SSPP and its assets, PGE has instituted a multi-disciplinary governance structure to assess how these assets might be used in the future – especially -- (1) in a manner that is consistent with the original funded purpose and (2) to optimize its value to PGE customers as a grid-integrated asset. The list below enumerates the identified use and valuation cases and their status as of this writing.

1. Respond to transactive node/transactive signal (Completed)
2. 400 kW of demand response benefit (Underway)
3. 1.3 MWh of energy shift from on-peak costs to off-peak costs (Completed)
4. 2 to 4 MW of real-time voltage & frequency for system OPS (Underway)
5. kVAr support and control on the distribution feeder (Underway)
6. ≈ 1.2 MWh of off-peak ability to absorb excess wind power
7. 5 MW load response to under-voltage load shedding event (Completed)
8. Real-time solar integration utilizing Kettle Brands' solar output signal (Completed)
9. Up/Down frequency regulation (Completed)
10. Distribution automation using advanced, intelligent relays
11. Adaptive Conservation Voltage Reduction [ACVR] (Underway)
12. Use as a dispatchable standby generation [DSG] resource (Completed)
13. Emergency power for OR Nat'l Guard command structure at Salem Airport
14. Using the BIS for Intra-hour Load Balancing (Underway)

Two levels of decision and advisory governance are established. The first involves a high level committee that includes PGE officers; this committee addresses policy and program direction around PGE's overall Smarter Grid efforts. The second committee is *ad hoc* and draws from many disciplines within PGE; includes senior managers and technical staff and focuses exclusively on the future uses of the SSPC assets – especially the battery-inverter system (BIS).

Discussion of Proposed Use and Valuation Test Cases Specific to the SSPC

Each proposed use and valuation test case specific to the SSPC is discussed in more detail below. In each case there is some attractive quality that makes the case interesting if not compelling. Regardless of whether the use case "makes the cut" there is no question that important learnings will occur to further PGE's experience with the unique capabilities of the SSPC battery-inverter system and these are valuable in their own right.

Proportional use of either power or energy or both are still speculative at present. This will depend on later optimization of the Battery Inverter System – especially if concurrent uses are contemplated. The inherent assumption for concurrent uses is that: "the stacked benefits outweigh the associated "stacked costs". That said, it is also entirely possible that the BIS may have "one use" as its best and highest value application. If multiple uses are contemplated PGE has joined with the Pacific Northwest National Laboratory to use its optimization tools for energy storage that are now becoming available (see Sources). Pacific Northwest National Laboratory (PNNL) has included its services with funding provided by US DOE in helping PGE value and optimize these use cases. It is anticipated that 9 to 10 use cases will be individually validated by 2016 and PNNL will then enter the picture to help evaluate optimization and prioritization.

Table 1 summarizes each item across several parameters for ease of comparison. Incremental costs above what has already been spent (Sunk cost for the SSPC is about $20 million) are also provided in the table. For ease of comparison, Figure 2 shows use cases ordered by increasing incremental cost for the cases where this is knowable as of this writing (excludes Use Cases #13 and #14 where currently only paper studies involving largely internal staff are proposed at present).

1. *Battery Inverter System (BIS)- Response to Transactive Incentive Signal*
   Completed; this capability has already been demonstrated. As discussed earlier, PGE delivered five assets in its role as a sub-contractor to Battelle as part of the Pacific NW Smart Grid Demonstration Project. All five assets were demonstrated to be responsive to the transactive incentive signal. The BIS in particular, has been responsive for the better part of a year and per Project guidance will successfully close this portion of the demonstration at the end of August 2014. Simple arbitrage nets less than $10,000 per year based on California-Oregon Border Index and is not being pursued any further at this time.

2. *400 kW of Demand Response Benefit (DR)*
   Underway in 2016; Two of the assets demonstrated as responsive to the transactive incentive signal included demand responsiveness involving: (1) twenty radio-controlled residential water heaters and (2) 51 commercial entities that volunteered to participate. Control for these assets involved automated interaction with PGE's Smart Power software platform and a "human in the loop" rubric to ensure a smooth experience for participating PGE customers. To involve the BIS in a demand response role is straightforward. The only technical hurdle is how to best receive the demand response signal. If a simple "manual" response is adequate, no further effort would be needed. If an automated DR is desired, this would incur a small expense to produce a software control program. This use is entirely feasible. Upon completion it remains to assess its valuation and at what BIS power proportion is rational.

3. *1.3 MWh of Energy Shift from on-Peak Costs to Off-Peak Costs*
   Completed; as part of the Pacific NW Smart Grid Demonstration, this control already exists and for largely this purpose. At the conclusion of the Demonstration and in the likely event that a regional transactive control center no longer exists to carry the demonstration further – then control would be simplified to target just a peak shifting function. This would incur a small cost to create (or possibly modify) a much simplified, automated control rubric. This use is entirely feasible. Upon completion it remains to assess its valuation and at what BIS energy proportion is rational.

4. *2 to 4 MW of Real-time Voltage Support for System Operations*
   Underway; this use case does require more operational definition; at a minimum or in the simplest case, the present SSPP controls might be replicated for manual System Operations control. This could also be automated so that voltage control would respond without operator intervention. This use is entirely feasible. Upon completion it remains to assess its valuation and at what BIS energy proportion is rational. Portland State University's Power Engineering Department under the auspices of Dr. Robert Bass is supporting PGE staff in validating this use case with results targeted for completion in 2016.

5. *kVAr Support and control on the Distribution Feeder*
   Underway; The SSPP BIS can already perform a kVAr support function albeit only under manual control as of this writing. To automate this function requires the creation and installation of basic control software. This use is entirely feasible. Upon completion it remains to assess its valuation and at what BIS energy proportion is rational. Portland State University's Power Engineering Department under the auspices of Dr. Robert Bass is supporting PGE staff in validating this use case with results targeted for completion in 2016.

6. *≈1.2 MWh of Off-Peak ability to Absorb Excess Wind Power*
   Using the BIS to absorb excess wind generated energy would require obtaining an appropriate signal from a wind generation facility. In 2013 this feature was conceived and incorporated as part of a PGE capital job that involved the test emplacement of an advanced LIDAR anemometry instrument atop a wind turbine at PGE's Bigelow Canyon Wind farm. This capital job was approved for initiation in 2014. PGE's Scott Mara in the PSES Department is responsible for this capital job. This use is entirely feasible. Upon completion it remains to assess its valuation and at what BIS energy proportion is rational.

7. *5 MW Load Response to Under-voltage Load Shedding Event*
   Completed; this capability has already been demonstrated as one of the asset functions delivered by PGE in its contractual obligation as part of the Pacific NW Smart Grid Demonstration Project. This effort culminated in the creation of a high reliability zone (HRZ) whereby 1 MW of power was supplied to the feeder under a load shedding scenario. The BIS served as the intermediary to ensure that load could be picked up essentially instantaneously during the shedding event. To complete the high reliability rubric, power supply was then smoothly transferred to a temporary 1 MW diesel power generator that had been attached to the feeder for that purpose. [24]

8. *Real-time Solar Integration Algorithms Utilizing Kettle Brands' PV Solar Output Signal*
   Completed; This use has already been demonstrated in the following manner – the nearby Kettle Brands potato chip factory graciously allowed PGE to obtain the output signal, via radio from its 114 kW roof-mounted solar photovoltaic (PV) system. This signal, in combination with the ability to either store or release energy via the BIS is then used to: (1) Reduce peak load on PGE's Rural feeder line and (2) Reduce significantly, the load variation on the feeder to be more in line with the historically-modelled "ideal" load curve. These outcomes are attractive as they reduce the wear and tear on PGE's substation transformers[25] and at the same time helps integrate the intermittent output that is characteristic of solar PV systems.

9. *Frequency Response Test and Deployment*
   Completed; this use has already been demonstrated and done so at the specific request of PGE's Transmission Services Department.[26] In completing this demonstration, a frequency

[24] Although PGE used a 1 MW diesel generator to perform this function, the SSPP Smart Power Platform has the capability to engage three of PGE's dispatchable standby generators (DSG) in this same role. This ability to tie in the DSG resource via transactive energy control was also demonstrated as part of the Pacific NW Smart Grid demonstration project.

[25] For example: Fewer load tap changes (LTC) in response to less voltage and feeder load demand variability

[26] The effort supports PGE compliance with NERC BAL-003-1 (implemented April 1, 2015) on the need to respond adequately to an off-normal event. At the conclusion of the SSPP, the BIS at the Salem Smart Power Center has been used for frequency support to help PGE comply with this NERC requirement.

regulation screen was created to allow an operator at the SSPP control room to enter frequency setpoints (high and low) to which the BIS will respond. The operator also has the option to enter the kW of power in response to an event— up to 5,000 kW.[27] With setpoints in place and response maximum in play, the SSPP BIS can be set to automatically respond to unexpected frequency excursions.

10. Distribution Automation Using Advanced, Intelligent Switches

Four advanced Intellirupter Switches made by S&C Corporation were installed by PGE as one of the five asset deliverables for the Pacific NW Smart Grid Demonstration project. These relays are strategically placed on the Rural Feeder to allow automated switching control in the event of a fault in some portion of the line. These relays can routinely and rapidly query the line with time-stamped pulses to ensure continuity and to quickly localize a fault. These switches have been tested and shown to be responsive to transactive energy control. Nonetheless, there is much more that should be explored to fully utilize their capabilities especially in fault isolation where instead of the entire feeder being rendered off line in response to a fault, the use of these switches would isolate only the affected portion of the line. To press forward with this innovation, an internal PGE R&D project has been scoped to further automate and incorporate the use of these switches on PGE's grid. As of this writing, these switches have been "jumpered" off-line awaiting more formal studies of their full capabilities.

11. Adaptive (Dynamic) Conservation Voltage Reduction [28]

Underway: This use is similar to static conservation voltage reduction (CVR) except that with the BIS in play it is possible to reduce voltage (and thus power) adaptively over the entire length of the feeder line. This is much more attractive and has the potential to yield higher energy savings to benefit PGE's customers. The approach would be to use existing metering on the Rural Feeder to develop a feeder voltage profile. Following that, the Oxford substation voltage regulators can be temporarily disabled so that the SSPP inverters can assume the voltage regulation function. The goal is that during times of peak or unexpected demand, voltage can be regulated lower dynamically to reduce the peak power and to more closely match the historical feeder voltage profile. [29]

[27] Although 5,000 kW is within the capability of the SSPP battery inverter system, the setpoint is generally held to 3,000 kW to ensure that the lithium ion battery is not fully discharged in order to help preserve its expected life.

[28] PGE staff learned of this use from colleagues at Lower Valley Energy – see: https://conduitnw.org/Pages/File.aspx?RID=2062; Lower Valley is one of the eleven utilities participating in the Pacific NW Smart Grid Demonstration project; PGE is grateful for this shared learning.

[29] Explicitly: $P = V^2 / R$; Where:

P = Power
V = Voltage
R = Resistance

i.e. Power can be reduced on the resistive component of the load proportional to the square of the voltage

12. *Use as a Dispatchable Standby Generation Resource*

    Completed; as of this writing, PGE has 107 MW of capacity contracted for use as dispatchable standby generation (DSG) during periods of extraordinary peak power demand. In this arrangement, all of the consenting facilities deploy backup diesel-powered reciprocating engines that are capable of rapid startup as well as black start use. The BIS has the ability to provide this same *non-spinning reserve* service and add 2 MW to this DSG tally. This required that control software be replicated to integrate this resource as part of PGE's DSG proprietary GenOnSys control and operations package. Essentially this reproduced operational control of the SSPP BIS to the DSG control center – which was actually part of the original design. It remains to assess its valuation and at what BIS power and energy proportion is rational.

13. *Emergency power for OR National Guard Command Structure at the Salem Airport*

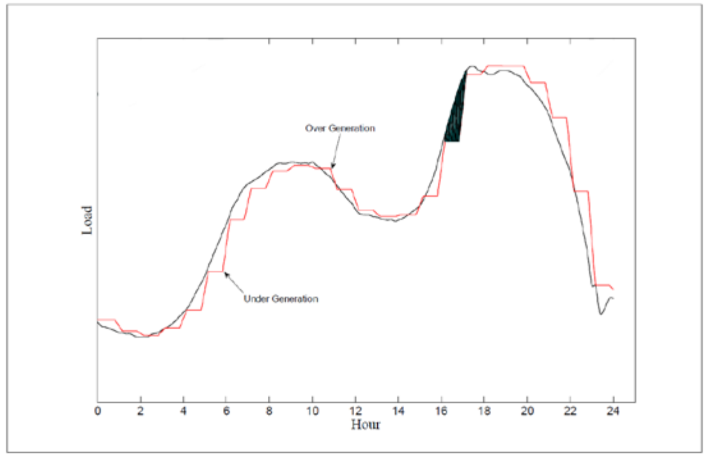
    Not Feasible under Current Conditions: As Salem area businesses and institutions have become increasingly aware of the SSPC, its battery inverter system (BIS) and respective capabilities - PGE staff are approached with ideas for possible, additional uses of the BIS that are locational in nature. In this instance, a senior officer in charge of the Oregon National Guard's emergency facilities toured the SSPC and asked whether the BIS could be used to provide backup power to a Guard command center located at the nearby Salem Airport.[30] This would require an assessment as to whether the Rural Feeder line can be extended to connect to this location and provide this use – capacity-wise. A portion of Rural Feeder in this direction is underground and the SSPC is actually within reasonable proximity so that the inquiry is imaginative, serendipitous and potentially within the bounds of reason. A T&D review has since noted that the connection to the Rural Feeder is not feasible due to load constraints leading the conclusion that the use case is not feasible under current conditions.

[30] We understand that under some circumstances the Governor of Oregon can be located here to direct emergency response; the structure houses a command and logistics center specifically for emergency deployments especially where OR National Guard helicopters are required as part of the response. The structure is seismically qualified and roughly 10 blocks from the SSPC.

14. Using the SSPC Battery Inverter System for Intra-hour Load Balancing

Underway; PGE staff are aware that the SSPC BIS is capable of multiple, even concurrent uses. This use case assesses the possibility that the energy stored in the battery can be used for helping "fill in the daily feeder load variation as it deviates from an ideal load profile". Figure 1 illustrates this potential.

Figure 1 Using the SSPC BIS for Load Balancing (see PNNL-23040)



In reviewing the graph we note that: (1) it is a similar application for the BIS use in helping levelize and integrate solar PV as part of the feeder load profile [Use Case #8]; (2) filling in the variation requires fairly small and thus manageable amounts of power and (3) such constant but small movements of energy into and out of the battery are well within the design of the system. Portland State University's Power Engineering Department under the auspices of Dr. Robert Bass is supporting PGE staff in validating this use case with results targeted for completion in 2016.

SSPC Operation, Maintenance, Program and Remote Operation

Routine custodial maintenance (cleaning, landscape upkeep, etc.) of the SSPC is budgeted annually by PGE Facilities Management (RC 785). The SSPC is monitored 24/7 for security via closed circuit cameras from the WTC Security center. Routine inspection of fire protection equipment and monitoring systems are institutionalized in PGE's safety department. A SSPC Operations Manual complete with a prominent section on Safety has been developed and tested for operator use and training. Programmatic control and administration for the SSPC battery inverter system is currently vested as a shared responsibility between PGE's Innovative Solutions group and PGE's Dispatchable Standby Generation (DSG) program. The DSG Control Center at PGE's Portland Headquarters in the World Trade Center can now remotely access and control the SSPC battery inverter system.

Next Steps and Outlook

Complete Use Case Validation

Use and valuation tests that remain unexplored were submitted for PGE R&D funding in 2016. PGE's Corporate Research and Development Committee approved funding to accomplish four use cases: Nos. 2, 5, 11 and 14.

Use Cases Nos. 1, 3, 7, 8, 9 and 12 are complete and deemed viable for further consideration. Several cases require relatively light effort and cost to complete (e.g., Use Cases Nos. 2, 4, 5). Use Case number 6 -- using the BIS to absorb off-peak excess wind energy -- will be performed as part of a 2015 PGE funded capital project and is awaiting data acquisition and transmission capability. Two remaining unvalidated test cases have relatively substantial programmatic impact and associated costs:

Use Case #10 – Distribution Automation using advanced, intelligent relays
Use Case #11 – Adaptive Conservation Voltage Reduction (ACVR)

Finally, Use Cases #13 and #14 have been proposed as internal studies to at least evaluate their feasibility for the proposed uses. As noted earlier, analysis of #13 concludes that the idea is unfeasible under current load constraints of the Rural Feeder line.

Optimization of Stacked Benefits / Costs

Technical Scope and Objective
PGE is currently targeting 9 to 10 validated use cases by mid-2016; if this is achieved we can then engage with PNNL in using of their optimization software for PGE's validated use cases. The US DOE has already committed funding to this effort with the groundwork laid in late 2015 between PGE and PNNL. PNNL is the lead national laboratory in performing optimizations for grid scale energy storage assets. The principal objective is to assess the best use(s) for the battery inverter system both from a grid perspective and from a dollar value perspective.

Project Dollar Value to PGE
Per the US DOE funding announcement (see US DOE Grid Modernization Laboratory Consortium – Awards of January 2016; Energy Storage Category, Project 1), PNNL has been awarded $2.5 million to optimize four (4) installations, in Vermont, Tennessee, and New Mexico in addition to the SSPC in Oregon over 2016-17.[31] As of this time, we are unable to ascertain the dollar value of this optimization phase of the project to PGE. PNNL has made it clear that PGE's only contribution to the optimization effort is in-kind labor and supply of data. To get a rough idea of the dollar value however –- it might be estimated as follows:

[$2.5 million - $0.5 million for PNNL Overhead] / 4 optimized projects =

Approximately $0.5 million of Value to PGE more or less

[31] This project is one of 88 funded projects as part of the US DOE Grid Modernization funding announcement

Next steps

- Complete use case validation
- Engage in early conversations with PNNL to answer the following questions:
  - What types of data are desired?
  - What format?
  - How much data?
  - How accurate?
  - What time scale?
  - What time scale granularity?
- Based on the outcome of collaboration with PNNL:
  - Assess any SSPC limiting conditions
  - Assess whether it is worthwhile to overcome limiting conditions
  - Assess any PNNL software limitations
  - Determine funding needs to overcome limitations
  - Perform optimization runs
  - Assess stacked benefits and concomitant stacked costs
  - Determine highest and best uses for the BIS at the SSPC
- Assess how applicable will be the approach & software for “Serial #2” after SSPC

Additional Sources

Balducci, P., et al., December 2013, *Assessment of Energy Storage Alternatives in the Puget Sound Energy System, Volume 1: Financial Feasibility Analysis*, PNNL-23040, 56 pages.

Wu, D. C. Jin, P. Balducci, M. Kintner-Meyer., et al., December 2013, *Assessment of Energy Storage Alternatives in the Puget Sound Energy System, Volume 2: Energy Storage Evaluation Tool*, PNNL-23039, 28 pages.

Osborn, M., J. Heimensen, K. Kaufmann, J. Lovinger, E. Lovro and C. von Reis, June 2013, *Opportunities and Challenges for Portland General Electric’s Salem Smart Power Project (SSPP): An evaluation of the SSPP’s potential system benefits, cost-effectiveness, and market participation*; Research Paper, Portland State University; 25 pages.

J. R. Edge, C. Mercado, L. Parks, G. Patterson, and B. Walsh, June 2013, *Salem Smart Power Project - High Reliability Zone Microgrid Study: Designing a Self-healing Microgrid That Incorporates Distributed Energy Sources*; Research Paper, Portland State University; 25 pages

Table 22 – SSPC Use Case Status & Cost

Use Case Description	Comments	Approximate Cost
1. Battery inverter system (BIS) response to transactive incentive signal	**Completed**; this was a primary deliverable as part of the Pacific NW Smart Grid Demonstration project. During execution, the SSPP battery inverter system (BIS) responded to the transactive incentive signal for approximately 1 year beginning August 20, 2013.	$20 million (includes planning costs and overheads)
2. 400 KW of Demand Response benefit	**Underway in 2016**; This use case is very easy to demonstrate. The largest question is how a demand response signal can be acquired at the SSPC. A simple answer is "manually, by telephone". If done this way, the demonstration of the use case is "free". Alternatively, if we want to automate the DR signal coming into the SSPC and have it react to an automated PGE signal; the cost will be less than $5,000.	Zero or $5,000
3. 1.3 MWh of energy shift from on-peak costs to off peak costs	**Completed**; This is already what the transactive node does and thus, already in place. This could be simplified just to shift peak without using the present, sophisticated transactive control.	$3,000 - Controls would be very simple. Most of them already exist.
4. 2 to 4 MW of real-time voltage support for system OPS	**Underway**; Need more definition. The easiest thing to do is simply replicate the controls from the SSPC to System Operations (SysOps). Or, we could automate the BIS' response to voltage & frequency so operators do not intervene. Portland State University's Power Engineering Department under the auspices of Dr. Robert Bass is supporting PGE staff in validating this use case with results targeted for completion in 2016.	$5,000 to $10,000

Use Case Description	Comments	Approximate Cost
5. kVAr support and control on the distribution feeder	**Underway**; This is straightforward to demonstrate; can already demonstrate this manually. To automate this function will require some very basic controls to be installed. Portland State University's Power Engineering Department under the auspices of Dr. Robert Bass is supporting PGE staff in validating this use case with results targeted for completion in 2016.	$3,000
6. ≈ 1.2 MWh of off-peak ability to absorb excess wind power	Would need to get the wind signal from an accessible power source. This work is included in a 2014 approved capital project for PGE PSES' test of an advanced wind prediction effort using LIDAR instrumentation at PGE's Biglow Canyon Wind farm	$0 additional; Funds already provided in existing capital project.
7. 5 MW load response to under-voltage load shedding event	**Completed** - HRZ 1 MW Test successful. Team has decided not to pursue this further.	> $1,000,000
8. Real-time solar integration algorithms utilizing Kettle Brands' solar output signal	**Completed**; can use the BIS and the solar signal from Kettle Brands to: (1) reduce peak load on the Rural Feeder and (2) reduce significantly, the load variation on the Rural Feeder to be more in line with the historically modelled "ideal" load curve.	$20,000
9. Frequency Response Test and Deployment	**Completed;** a frequency regulation screen has been built that allows the operator to enter the frequency setpoints (high and low) to which the BIS will respond. Also, the operator can enter the kW of power in response to an event, up to 5 kW. As of this writing the BIS responds to 2 to 3 under frequency events per month. Effort was funded by PGE Transmission Operations at $3,000 incremental cost.	$5,000
10. Distribution automation using advanced, intelligent relays	PGE R&D project has been scoped to incorporate / further test four (4) already mounted Intellirupter Relays (S&C) on the Rural feeder; Likely to be undertaken at a future time.	$110,000

Use Case Description	Comments	Approximate Cost
11. Adaptive (Dynamic) Conservation Voltage Reduction	**Underway**; PGE can use existing metering on the Rural Feeder to develop a feeder voltage profile. Then PGE can temporarily disable the voltage regulators at the substation and use the inverters for voltage regulation. The goal is that during times of peak or unexpected demand, voltage can be regulated lower adaptively to reduce the peak (Power = V^2/R). This approach is a dynamic version of the more conventional static conservation voltage reduction (CVR) rubric.	$30,000
12. Incorporating the SSPC BIS as part of PGE's dispatchable standby generation (DSG) program	**Completed**; This contributes 2 MW of DSG capacity (for 0.5 hour duration) to the present ≈107 MW of PGE DSG program. The original vision for the BIS was to actually be controlled from the World Trade Center DSG control room as part of PGE's proprietary GenOnSys software package. This control has now been affected as part of this use case.	< $30,000
13. Emergency power for OR National Guard Command Structure at the Salem Airport	**Not Feasible under Current Conditions**: Assess whether the BIS could be used to provide backup power to a National Guard command center located at the nearby Salem Airport. A portion of the Rural Feeder in this direction is underground and the SSPC is actually within reasonable proximity. T&D assessed whether the Rural Feeder line can be extended to connect to this location and provide this "locational" use. Their conclusion that adding the structure to this feeder is not feasible due to load constraints.	Internal Costs
14. Using the SSPC Battery Inverter System for Intra-hour Load Balancing	**Underway**; This use assesses if the battery energy can be used for helping "fill in the daily feeder load variation as it deviates from an ideal load profile". Approach is similar to the BIS use in helping levelize and integrate solar PV as part of the feeder load profile [Use Case #8]; filling in the variation requires fairly small and thus manageable amounts of power and such constant but small movements of energy into and out of the battery are well within the design of the system. Portland State University's Power Engineering Department under the auspices of Dr. Robert Bass is supporting PGE staff in validating this use case with results targeted for completion in 2016.	Internal Costs; R&D collaboration with PSU Power Engineering group

Appendix 9. Smart Inverters

OPUC Condition: Continue to document & report on efforts related to 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 (see pg. 32,).

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 ≥ 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 RD&D on how to maximize smart inverter benefits
- Advocate for widespread adoption of smart inverter[32]
- Involvement in OPUC workshops on smart inverters
- Continued involvement in the development of industry inverter standards, particularly UL-1741 and IEEE-1547

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

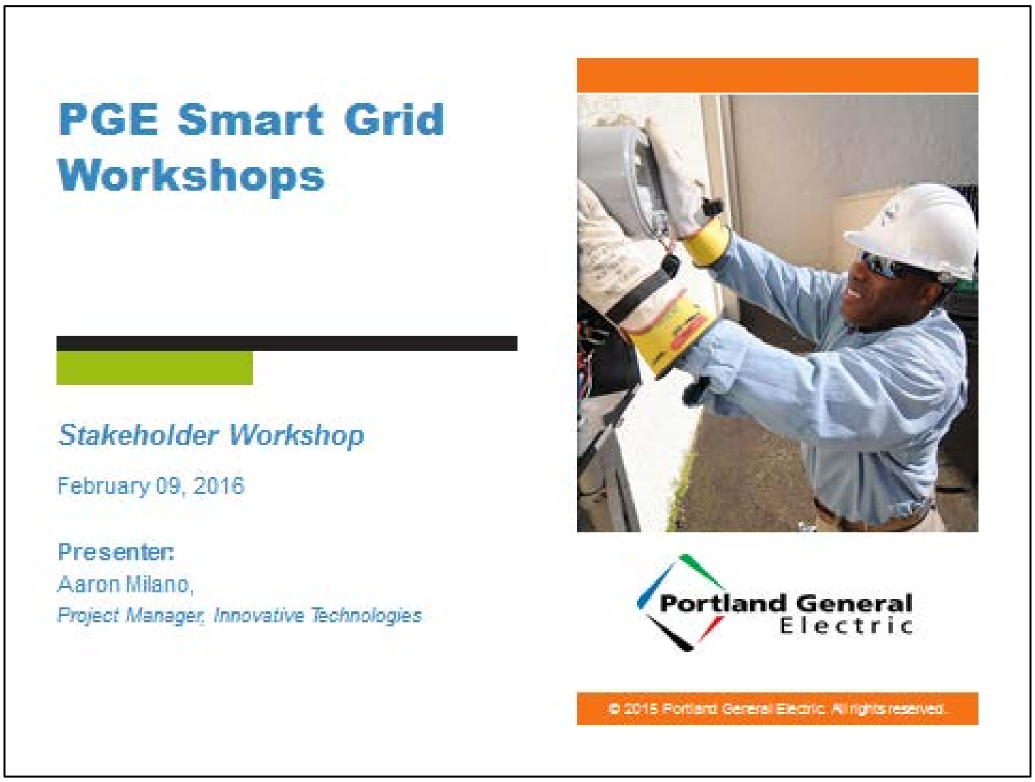
Appendix 10. Customer Education and Outreach

OPUC Condition: PGE begin a recurring stakeholder meeting where Staff & stakeholders discuss customer education, outreach, marketing, and related strategies

PGE held a workshop with Stakeholders on February 9, 2016 to kick off a discussion on customer education, outreach, marketing, and related strategies.

Attendees included OPUC Staff, ETO, and CUB. At the meeting PGE presented a history of smart grid outreach (including AMI and SSPC) and program-specific marketing plans/material for Energy Partner, Flex, and Rush Hour Rewards.

A copy of the presentation is included on the subsequent pages.



Smart Grid Outreach & Communications

Agenda:

- Background
- History & Approach
- Program Material
- Staff Discussion

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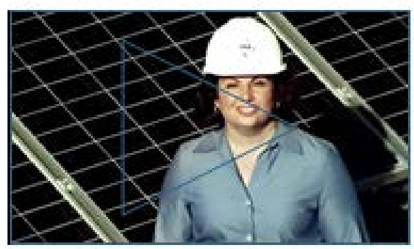
Smart Grid: Foundational Education



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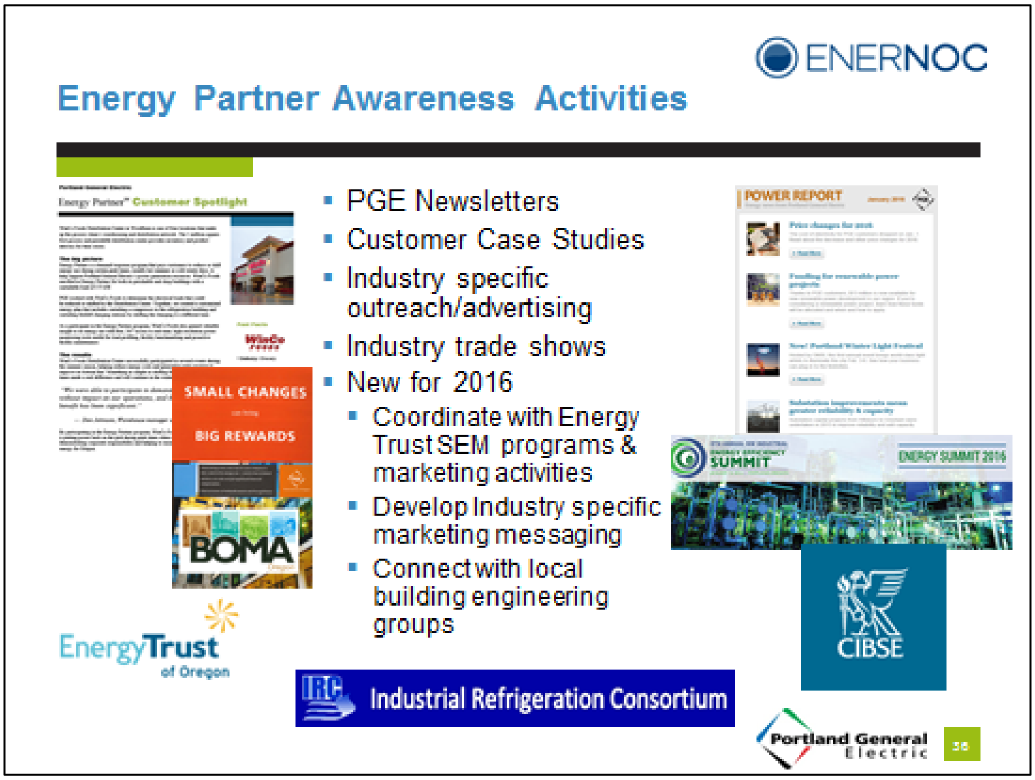
ENERNOC
Energy Partner Awareness Activities
PGE Newsletters
Customer Case Studies
Industry specific outreach/advertising
Industry trade shows
New for 2016
Coordinate with Energy Trust SEM programs & marketing activities
Develop Industry specific marketing messaging
Connect with local building engineering groups
Energy Partner Customer Spotlight
SMALL CHANGES
BIG REWARDS
BOMA
POWER REPORT
ENERGY SUMMIT 2016
SUMMIT
CIBSE
EnergyTrust of Oregon
IRC Industrial Refrigeration Consortium
Portland General Electric
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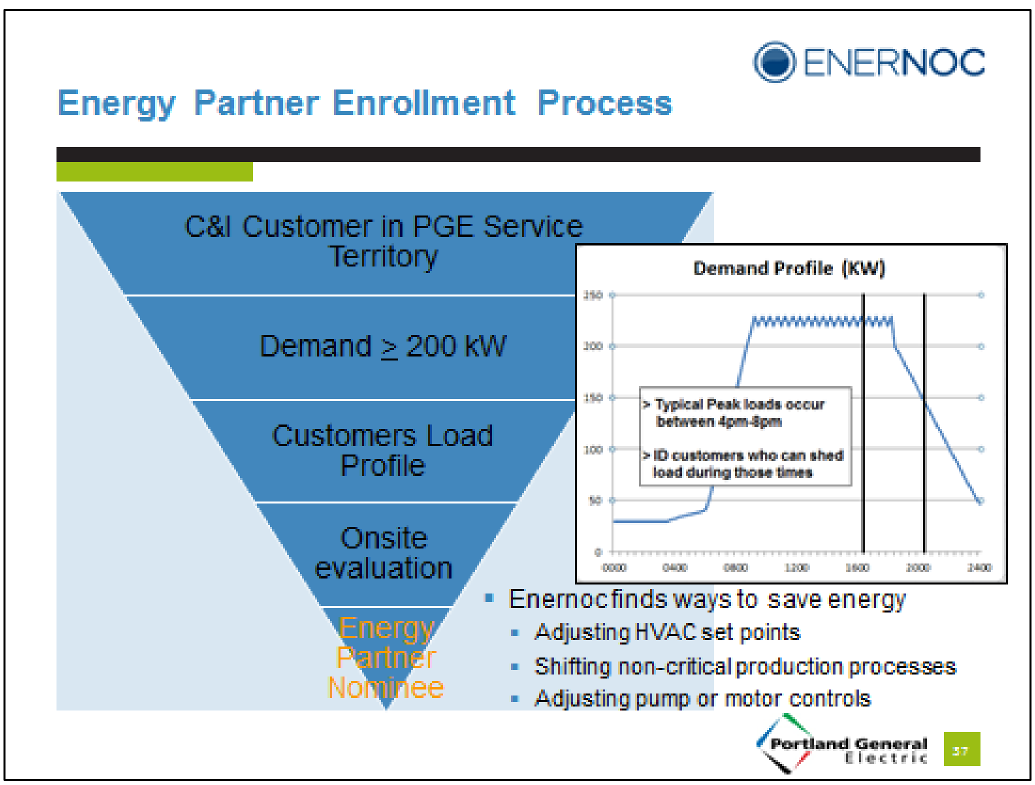
ENERNOC
Energy Partner Enrollment Process
C&I Customer in PGE Service Territory
Demand ≥ 200 kW
Customers Load Profile
Onsite evaluation
Energy Partner Nominee
Demand Profile (KW)
250
200
150
100
50
0
0000
0400
0800
1200
1600
2000
2400
> Typical Peak loads occur between 4pm-8pm
> ID customers who can shed load during those times
Enernoc finds ways to save energy
Adjusting HVAC set points
Shifting non-critical production processes
Adjusting pump or motor controls
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Flex Marketing

- Customer expectations, preferences, and motivations differ widely.
- Marketing research drives messaging and marketing materials that motivate customers to become active and participate in PGE programs.
- Mass customization is the preferred (but often costly way) to match marketing with customers. As customization costs decrease more innovative/targeted marketing can be deployed.
- The way we use energy is changing rapidly. Energy marketed as commodity is being replaced by energy marketed as a personalized choice and experience.
- PGE uses mass customization in marketing the pricing pilot to customers with their preferred messaging that acts as a catalyst/driver for them to make a change.

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Recruitment Material – Draft – Behavioral Theme

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Recruitment Material – Draft – Control Theme

CONTROL:
JUST A MATTER OF TIME
RECRUITMENT DIRECT MAIL (PTR)

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Recruitment Material – Draft – Community Theme

COMMUNITY:
NO OREGONIAN IS AN ISLAND
RECRUITMENT DIRECT MAIL (PTR)

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Nest Rush Hour Rewards

- PGE/Nest deployed the first summer and winter rush hour rewards program in the US
- New challenges for Nest to accommodate a winter and a summer recruitment season:
  - Identification of different heating/cooling systems
  - Need of differentiating messaging between winter and summer
  - Moving from a seasonal recruitment approach to a 365 day effort
- Nest rush hour rewards heavily dependent on Nest outreach to existing Nest thermostat customers and newly acquired customers.
- PGE is providing significant inbound traffic to Nest rush hour reward enrollment platform. Much more impactful than what Nest observes from regular utilities/utility programs.
- PGE is building a secondary platform that promote/market Nest thermostats, installations, ETO incentive uptake, and PGE/Nest rush hour rewards enrollment.

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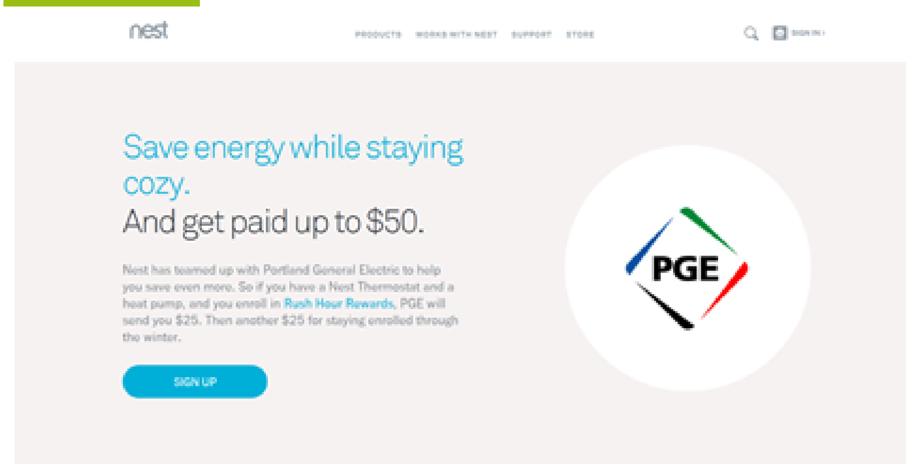
Nest Rush Hour Rewards – Landing Page #1



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Nest Rush Hour Rewards – Landing Page #2
Meet the 3rd gen Nest Learning Thermostat.
A bigger, brighter way to save energy.
Watch video
Auto-Schedule
Auto-Away
Energy History
Remote control
75
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Nest Rush Hour Rewards – Landing Page #3
Rush Hour Rewards
Sign up, pay less, stay comfortable.
Portland General Electric
45

Energy Trust/PGE Collaboration

Featured utility promotions

Portland General Electric

- **Rush Hour Rewards**—If you have a Nest Thermostat and a heat pump, enroll in Rush Hour Rewards and PGE will send you up to $50. You can stay cozy this winter, save energy and help PGE lower demand during energy rush hours. Learn more.

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Staff Discussion

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Appendix 11. Non-Wire Alternative Research

OPUC Condition: PGE should include the status of non-wire alternative distribution upgrade research, including possible pilot projects.

This condition refers to the R&D Project titled "Assessing Energy Storage as a Non-Wire Alternative for Transmission & Distribution" which was described in the 2015 Smart Grid Annual Report (p.55). As indicated in 0, "Research and development necessarily implies a certain amount of fluidity in targeted research topics." This specific research project was not prioritized after the 2015 general rate case and the passing of HB 2193, and as such has not yet commenced. PGE recognizes the value of this specific study and will work with PSU to outline a paper in 2016.

Despite this specific effort not being yet underway, PGE is taking a variety of alternative steps to evaluate non-wire alternatives. The Company considers "non-wire alternatives" to use of distributed energy resources or other smart grid technologies instead of conventional transmission & distribution infrastructure to reduce equipment and system overloads. PGE already employs intervention tactics beyond asset replacement to reduce risk on the T&D system, such as system reconfiguration. Additionally, PGE anticipates many of the pilots and research projects highlighted throughout this report are building PGE's collective knowledge of non-wire alternatives:

- System Automation
- Energy Storage, Microgrids, DSG
- Volt-Var Optimization /Conservation Voltage Reduction
- Demand Response

As identified in the Grid Optimization Roadmap on page 17, PGE anticipates the development of a locational DER pilot in the 4-5 year timeframe which would potentially utilize one of these resources with the intent to deploy customer programs that reduce risk on the T&D system.

Appendix 12. Research, Development, and Pilot Summary

OPUC Condition: PGE should provide a summarizing table of all research, development, and pilot projects, their respective descriptions, expected benefits and costs.

As outlined in Appendix 4, PGE has been developing a standard cost-effectiveness methodology for Demand Response. Additionally, the OPUC has a docket open for the resource value of solar (RVOS), the Energy Trust has a methodology for evaluating cost-effectives for energy efficiency, and the Company is evaluating value streams of energy storage associated with HB 2193. As such, no standard evaluation protocol exists for quantifying benefits of some smart grid initiatives. Looking forward, the Company anticipates a aligning these efforts such that other smart grid initiatives could be informed future by cost/benefit evaluations. As such, quantified benefits in the table below are estimates and may change as methodologies for cost-effectiveness are standardized.

<table>
<tr><th colspan="2">Initiative</th><th>Status</th><th>Page</th></tr>
<tr><td colspan="2">T&D Analytics</td><td>Pilots & Evaluation</td><td>23</td></tr>
<tr><td colspan="4">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.
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.</td></tr>
<tr><td>Benefits:

Operational Efficiency: The system will help PGE develop use cases for leveraging real-time data streams to improve operational efficiencies.</td><td colspan="3">Cost:

2016 Budget: $ 230,000.00</td></tr>
</table>

Initiative		Status	Page
Distribution Automation (DA)		Pilots & Evaluation	30
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. 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	31
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)		

<table>
<tr><th colspan="2">Initiative</th><th>Status</th><th>Page</th></tr>
<tr><td colspan="2">Energy Storage</td><td>Planning</td><td>29</td></tr>
<tr><td colspan="4">Description:

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. To date, the team has developed a project vision which is to create a diversified storage portfolio (in location and storage type) while integrating all resources through PGE system operations. 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/decarbonization</td></tr>
<tr><td>Benefits:

Improved reliability of transmission, distribution, and customer systems, improve integration of renewable resources, ancillary services (i.e. frequency regulation).</td><td colspan="3">Cost:

Currently under evaluation.</td></tr>
<tr><td colspan="2">Synchrophasors on Transmission System</td><td>Pilots & Evaluation</td><td>34</td></tr>
<tr><td colspan="4">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).</td></tr>
<tr><td>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</td><td colspan="3">Cost:

Estimated budget for installation at five substations and IT infrastructure required: $ 418,714.00</td></tr>
</table>

<table>
<tr><th>Initiative</th><th>Status</th><th>Page</th></tr>
<tr><td>Fault Detection (Distribution)</td><td>Pilots & Evaluation</td><td>33</td></tr>
<tr><td colspan="3">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. In 2016, PGE will test use cases for the FCIs and 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 2017 or 2018.</td></tr>
<tr><td>Benefits:

Improved fault detection & improved reliability: FCI information can help crews restore power faster and likely to lead in fewer truck rolls.</td><td colspan="2">Cost:

Approximate pilot Cost: $ 200,000</td></tr>
<tr><td>Flex: Pricing Research Pilot</td><td>Pilots & Evaluation</td><td>40</td></tr>
<tr><td colspan="3">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.</td></tr>
<tr><td>Benefits:

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.</td><td colspan="2">Cost:

2016 Budget: $ 1,038,083.00</td></tr>
</table>

Initiative	Status	Page
Energy Partner	Pilots & Evaluation	41

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:	*Cost:*
The primary expected benefits include reduced peak demand and ability to shift/curtail customer loads.	2016 Budget: $ 1,974,524.00

Initiative	Status	Page
Smart Thermostat Demand Response Pilot (Rush Hour Rewards)	Pilots & Evaluation	42

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:	*Cost:*
The primary expected benefits include reduced peak demand (estimated to be about 1-kW per customer) and ability to shift/curtail customer loads.	2016 Budget: $ 592,350.00

Initiative	Status	Page
Microgrid Reliability Real-time load modelling for S-Phasor	Research	43

Description:

The goal of this project is to better understand load models in order to advance protection of the next generation power transmission and distribution infrastructure. With assistance from the growing Phasor Measurement Unit (PMU) network at Oregon State University (OSU), a composite dynamic load model can be estimated in real time and provide useful insight into the design of micro-grid protection schemes. This will address challenges such as reverse flows, automatic reclosing, or delayed relay tripping; it will also yield insights for Real-time power flow and load composition estimation. Modelling will Leverage sparse distribution of sensors with a machine learning framework together with in-lab testing and model validation.

Benefits:	Cost:
This project will provide PGE with insights about the benefits of deploying PMUs at the distribution level: Improved analysis of anomalies from modern, non-traditional loads, as well as synchronization between transmission and distribution level sensing.	2016 Budget: $ 25,000.00

Initiative	Status	Page
EPRI Program P94: Energy Storage & Distributed Generation	Research	44

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.

Benefits:	Cost:
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	2016 Budget: $ 91,000.00

<table>
<tr><th colspan="2">Initiative</th><th>Status</th><th>Page</th></tr>
<tr><td colspan="2">PSU-PGE Smart House Design Competition</td><td>Research</td><td>44</td></tr>
<tr><td colspan="4">Description:

PSU-led, campus-wide competition to encourage broad look at solutions for smart homes. The interdisciplinary competition will create broad perspectives on solutions for grid/renewable friendly “smart” homes. Focus is on solutions for homes that have the ability to use and/or store renewable energy when over generation occurs as wind and solar generation approaches 50% in California and later in WECC. This “project” funds the prize money. Judging would come from PSU, PGE and other third parties.</td></tr>
<tr><td>Benefits:

Learnings on how building design & control can enable renewables integration and can aid in periods of over-generation.</td><td colspan="3">Cost:

2016 Budget: $ 6,000.00</td></tr>
<tr><td colspan="2">EPRI Program 174: Integration of Distributed Energy Resources</td><td>Research</td><td>45</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.
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="3">Cost:

2016 Budget: $ 35,000.000</td></tr>
</table>

Initiative	Status	Page
SSPC Use Case Test & Validation	Research	45
Description: The battery inverter system (BIS) at SSPC is a novel asset to PGE, and one of only a handful in the country. Because of this unique platform and the recent passage of House Bill 2193 requiring PGE to procure an additional 5 MWh of energy storage, it is important to continue to advance PGE's learning about how to best operate the asset and value the services it provides. This project will further PGE's experience with the capabilities of the SSPC BIS system and will help position PGE and its customers for success under HB2193, including: 1. Develop an algorithm to determine the BIS' round trip efficiency 2. Test the volt/var use case 3. Test the adaptive conservation voltage reduction use case 4. Create and test a use case optimization routine		
Benefits: This project increases the value of the services SSPC provides to PGE customers as a grid-integrated asset by optimizing the operation between use cases based on economic value and system reliability. This could result in things like peak load reduction, frequency response, and energy savings.	*Cost:* 2016 Budget: $ 80,000.00	
Develop Model to Assess DSG Program Target Capacity	Research	46
Description: The current financial model for the DSG program is simplistic and does not assess the need for incremental DSG units. This makes it difficult to understand the value of each additional DSG Megawatt on PGE's system. In order to plan for the growth and future of the program, a model must be developed that integrates with all of PGE's generating resources, load profiles and wholesale markets. PGE is using Energy and Environmental Economics, Inc. (E3) to develop resource adequacy needs assessments for the IRP group. This project would leverage the existing E3 model by retaining them to perform follow-on work. This new project would break out separately each capacity resource (like DSG) to analyze the optimal level of incremental capacity for specific resources (currently, the model just lumps DSG capacity in with all other capacity resources).		
Benefits: Developing a comprehensive model will help the DSG and IRP groups understand to what level to develop this program and how important non-emergency resources are to the program. This model will help accurately determine the growth targets for the DSG program.	*Cost:* 2016 Budget: $ 30,000.00	

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<tr><th colspan="2">Initiative</th><th>Status</th><th>Page</th></tr>
<tr><td colspan="2">Joule Bank System -- Bulk Thermal Storage</td><td>Research</td><td>46</td></tr>
<tr><td colspan="4">Description:

This is a continuation of a unique, proprietary project started in October 2014 on the design and early prototyping of the Joule Bank System, a new, flexible, highly efficient, residential heating and cooling system based on heat pumps and thermal storage. Extensive collaboration has evolved on this project to ensure arms-length, third-party assessment.

Collaborating institutions include Harvey Mudd School of Engineering for thermodynamic assessment and modelling; Portland State University for initial prototype design and development. In 2015, PGE concluded theoretical and prototype development; in 2016 – it is anticipated that a “production” model will be tested under real-world conditions.</td></tr>
<tr><td>Benefits:

PGE estimates that 90% of peak demand can be eliminated by thermal storage & utility control. This study informs technology viability and demonstrated value.</td><td colspan="3">Cost:

2016 Budget: $ 35,000.00</td></tr>
<tr><td colspan="2">Battery Backup Field Demonstration, PSU Collaboration</td><td>Research</td><td>47</td></tr>
<tr><td colspan="4">Description:

The purpose of this project is to demonstrate a distributed, scalable control and installation architecture that would allow for relatively fast deployment to enable an aggregated resource of hundreds of MWs. PGE proposes to build a “microgrid” consisting of systems installed at 2 to 4 fire stations, or on a smaller scale, e.g. a residential house, and aggregated to operate as a single system through DSG’s GenOnSys control. The systems would provide backup power to the fire station or chosen site in the event of a power outage. The battery supply would allow power for up two days, and could be recharged in 5 hours with a portable generator to last another two days. Satellite fire stations have been considered because: 1) they are visible assets that would be desirable sites for backup power service, and 2) they are similar in electric characteristics to homes and/or to 240 volt service transformers (there are approximately 900,000 240 volt connection points in PGE’s service area).</td></tr>
<tr><td>Benefits:

When a grid outage is not occurring, PGE would use the energy storage and power capacity of the aggregated systems to serve the needs of power operations, including peak management, reliability and resiliency, regulation, renewable firming , ramp control, energy shift, load flow control, and economic dispatch.</td><td colspan="3">Cost:

2016 Budget: $ 125,000.00</td></tr>
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Initiative	Status	Page
EPRI-Related Demonstration of Smart Water Heaters & EVSE	Research	47

Description:

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This project involving smart water heaters - seeks to:

5) Validate technical approach of communication via CEA-2045
6) Develop first control strategies for 24x7x365 DR control
7) To extent possible, determine estimate of kW reduction achieved during periods of system peak demand
8) Obtain employee feedback about control approach and impact of control

This project continues an earlier EPRI-related effort and can still call on EPRI resources as it evolves into the future.

Benefits:	*Cost:*
At 100% customer adoption, Smart Water heaters could create 225 MW of peak demand reduction and 1500 MWh of load that PGE can dispatch to any part of the day -- all this at a cost that is less than 50% of the cost of a standard peaking plant.	2016 Budget: $ 40,000.00

Appendix 13. Related Dockets and Commission Orders

Table 23 – Related Dockets

Docket No.	Subject
AR 599	EV Program Application
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)