

2016 SMART GRID TECHNOLOGY REPORT

September 1, 2016

Filed pursuant to WAC 480-100-505



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Cover images (clockwise from top left): PSE’s Paul Arnold working in PSE’s Load Office, a rooftop solar installation, an electric AMI meter, PSE’s Paul Jusak leading a tour of PSE’s grid-scale battery project.

Executive Summary

When Puget Sound Energy (PSE) began implementing Automated Meter Reading (AMR) in 1998, there wasn't a lot of talk about a "smart grid." PSE recognized then, and now, that automated meter technology would improve the way we operated and deliver greater value to our customers.

Similarly, when PSE began building its automated transmission system over three decades ago, the company was driven by the need for enhanced real-time monitoring and system visibility. Today, a "self-healing transmission system" is considered a prime component of a smart grid. Over the years, other smart components have been deployed throughout our electric and gas systems, driven by PSE's mission to improve service, reliability and efficiency; enhance safe operations; and support customers in managing their electricity and natural gas consumption.

PSE is actively engaged in several projects that improve system reliability and provide more information and choice to customers. Here are a few:

- Our automated meter modules collect energy usage information from electric and gas meters that enables customers to check and manage their daily electricity and natural gas usage online.
- PSE has more than 4,000 residential customers with grid-connected solar and wind systems who generate their own power and supply excess energy back to the grid.
- We're improving reliability on our electric grid by expanding automation and installing grid scale storage.

The smart grid future promises the ongoing integration of new and improved technologies that enable data and information to flow securely to and from different end points and applications – from natural gas storage and electricity generators through the distribution system, to the meter, and into the customer's home or business. These new technologies enhance the customer experience by delivering better reliability and energy management tools to PSE customers. This "system of systems" is efficient, cost-effective and replaces or connects multiple stand-alone systems. Operationally, PSE is working to improve customer service and safety by using advanced monitoring, modeling, control and automation. It is streamlining existing processes and enabling data access for multiple uses across the organization.

Our approach continues to focus on leveraging our existing investments and experience in a careful, thoughtful manner, while taking into account customer value and security of the systems every step of the way. Experience shows that phased deployment and careful and ongoing selection of appropriate technologies creates success. This means fielding technologies that are cost-effective and able to deliver stable, proven capabilities for PSE and our customers. This is how PSE continues on the path toward a smarter energy future.

As PSE replaces obsolete systems, we're selecting equipment that comes with smart grid features as a standard; the same way a personal computer you buy today has significantly greater functionality than a computer you bought five years ago. These systems can touch almost every part of the company: technology, infrastructure, customers, workforce and operational processes. Because the smart grid is an evolution, PSE continues to keep compatibility, future-proofing, employee training and customer experience in mind throughout the process.

Over the next 10 years, PSE intends to:

- Deploy two-way automated metering technology to refresh the aging legacy AMR infrastructure
- Enhance the customer experience by automatically providing information and services to the customer related to: outage notification, start/stop service, usage data and other capabilities
- Expand deployment of self-healing technology that automatically reroutes power during outages to improve electric system reliability
- Deploy energy storage pilot projects and continue to research and evaluate emerging energy storage technologies

- Provide customers with easy-to-use energy management tools and information
- Integrate customer equipment, such as electric vehicles and customer-owned power generation
- Upgrade and replace aging infrastructure as needed – for IT networks, back-end information systems and the electric and natural gas systems – with consideration to implementing a smarter grid
- Evaluate and selectively deploy other customer energy management programs and pilot projects

In the past several years, PSE has deployed key foundational systems to enable smart grid capabilities. We have developed tools to better manage the customer experience from billing and service interactions to response times when outages occur. And with these systems, PSE can progress to applications like Demand Response and remote disconnects/reconnects for electric customers who change residences. Moreover, these systems have the capability to communicate specific information to customers through a variety of mediums like web, mobile devices and in-home displays.

There's no question that a smarter grid can bring many benefits to both PSE and our customers. A smarter grid enhances two of PSE's core objectives: maintaining high system reliability and efficiency and empowering customers with the ability to manage their energy efficiently. The bottom line: Getting the PSE smart grid right will benefit our economy, our environment and our customers for years to come.

Introduction

Smart grid refers to an energy supply chain that employs modern technology to enhance, integrate, and automate monitoring, analysis, control and communications capabilities along the entire grid. Smart grid technologies can impact the energy delivery chain from a power generating facility or natural gas storage facility all the way to the end-use application of energy inside a residence or place of business. The ultimate goals of smart grid are to enable utilities to offer more reliable and efficient energy service, and to provide customers with more control over their energy usage.

This report, filed in compliance with WAC 480-100-505, is the biennial follow-up to Puget Sound Energy's 2010, 2012 and 2014 Smart Grid Technology Reports. It updates PSE's plan for achieving a smarter system that benefits our customers and our utility operations. While this report is primarily focused on systems, programs and infrastructure supporting our electric business, PSE is also modernizing our natural gas infrastructure using many of the same types of solutions.

This report is divided into the following sections:

- **Background** – a working definition and vision of smart grid
- **Review of PSE's Smart Grid Initiatives** – an overview of PSE's decades-long experience with implementing smart grid components, as well as a progress report on 2015-2016 proposed activities
- **PSE's Current Approach** – PSE's strategy for and approach to implementing smart grid
- **PSE's Implementation Plan** – PSE's next two-year implementation plan and a 10-year roadmap
- **Glossary** – acronyms and terms defined
- **Appendices** – additional details reflecting PSE's smart grid technology initiatives consistent with the Commission's regulatory requirements

Throughout this report, we divide PSE's smart grid initiatives into three broad categories: 1) information technology (IT); 2) customer information and energy empowerment; and 3) electric grid infrastructure. In these areas we find that our employees and customers can work together through the smart grid technology initiatives to achieve the highest levels of safe, dependable, efficient and secure service.

Background

The electric grid has been called one of the most complex machines in the world. It's at the heart of the evolving national movement toward a smart grid. This smart grid is more reliable and efficient through automated monitoring, control and self-healing capabilities. It provides customers with better information, control and automation to manage their energy use. It engages customers with their utility in managing the overall grid through demand response or related programs, and it supports the adoption of new consumer-driven technologies such as renewable energy generation and electric vehicles.

This is the vision of smart grid: a robust and dynamic system that delivers value through improved system capabilities, optimization and energy utilization. From an operational perspective, smart grid deployments can be broken down into three major parts:

- The back-end information systems, also known as smart grid enablers, are comprised of major information and control systems. At PSE, these include the Customer Information System (CIS), the Meter Data Management System (MDMS), the Outage Management System (OMS), the Energy Management System (EMS), the Distribution Management System (DMS) and the Geospatial Information System (GIS).
- The advanced two-way communication infrastructure carries data and information between the back-end information systems and devices located either at the customer's premise (for example, meters, energy management systems and home automation networks) or at locations in PSE's T&D system infrastructure (for example, substations, switches and capacitors).
- Applications and assets that provide energy information, manage energy use, or enable distributed energy generation. Some of these applications also manage PSE's assets, such as devices located at substations, switches and capacitors.

Figure 1: Illustration of Potential Smart Grid Deployment

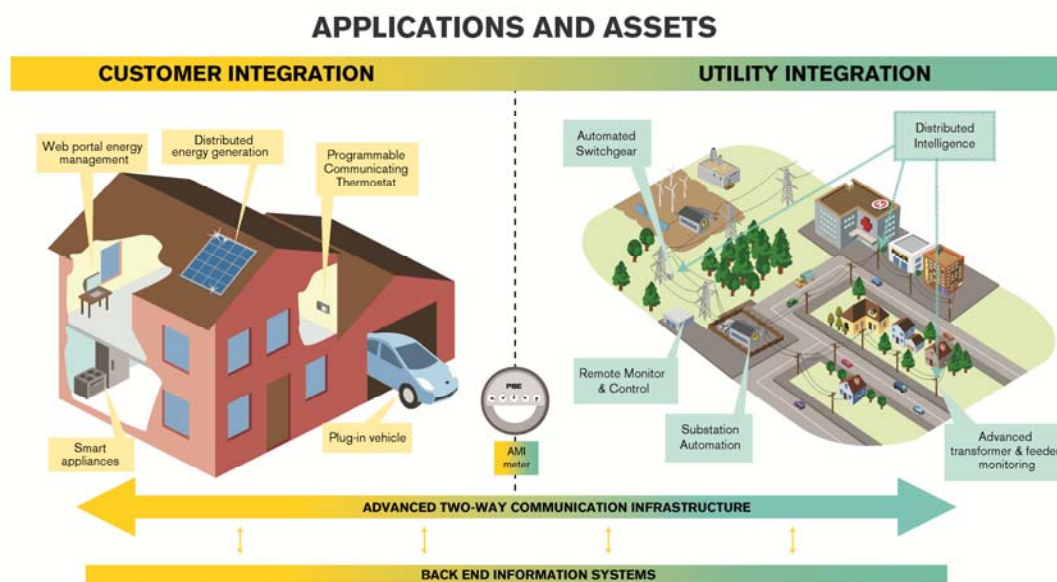


Figure 1 above displays some of the potential components of a smart grid, including customer and utility applications and assets, two-way communication infrastructure and back-end information systems. These aspects are all expected to benefit both customers and utility operations. These communication and control systems provide added capabilities, efficiency and flexibility to the electric grid. While there are many established and emerging smart grid technologies, there's still plenty of debate around the world about

how to achieve a smart grid in a way that's cost-effective and focused on the customer. This is a challenge that faces all utilities working to implement a smarter grid.

Success Factors

Smart grid technology advancements and investments will be made at multiple levels within the utility. This includes endpoint devices, physical grid equipment and IT systems that connect customers, the utility and the energy grid. The roll-out of this technology will continue to occur through careful planning, consideration of remaining useful asset life and the integration of existing assets, and the evaluation of the forward compatibility of technology.

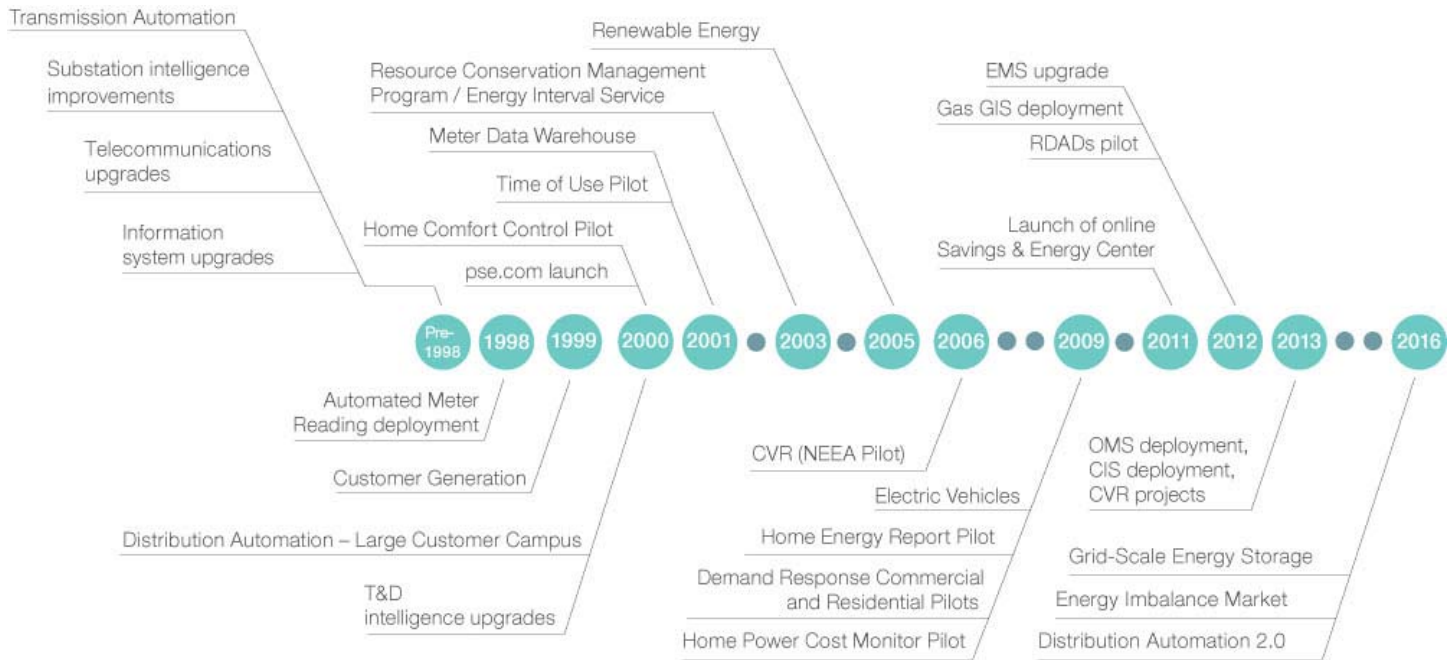
As energy companies chart their way to a smarter energy future, a number of variables, such as regional differences, environment, customer interest, and company size and organization will define the choices they make. PSE will work to address its own unique characteristics to successfully deploy new technologies, with concentration on the following factors:

- **Customer = Driver:** PSE will stay in tune with customers who are looking for ways to be more engaged (access to outage information, price and billing options), as well as those who are already actively engaged in energy matters (participation in energy efficiency programs and pilot projects, and early adopters of electric vehicles and distributed energy generation). Both the energy market and consumers will be an important driver of smart grid advancements for utilities.
- **Reliable service:** Residential and business customers depend on PSE every day for reliable service at a reasonable cost. It naturally follows that the pursuit of smart grid technologies should further enhance this mission.
- **Demand-side resource options:** In terms of generated electricity, PSE will need additional resources to meet future capacity needs. PSE's Integrated Resource Plan (IRP) defines PSE's electric forecast every two years. In its 2015 IRP, PSE anticipates adding 532 MW of conservation and Demand Response to its electric resource portfolio by 2021. Several options to deliver demand-side resources, including Demand Response and Conservation Voltage Reduction (categorized as distributed efficiency in the IRP) involve additional capabilities that fall within the definition of smart grid.
- **Renewable energy integration:** Renewable energy is of significant interest to PSE and our customers. PSE is already producing electricity from the wind and sun, and purchasing electricity generated from landfill and dairy waste products. We expect these renewable sources to be an increasingly important part of our energy future. Smart grid advancements need to consider renewable energy, distributed generation, energy storage and Demand Response in a way that is aimed toward managing peak loads, enhancing asset use and expanding the energy distribution capabilities of smart grid.
- **Infrastructure and operational opportunities:** Like many energy companies, PSE is faced with aging equipment that will need to be modernized or replaced to ensure reliability for our customers. This presents an opportunity: updating these systems will allow us to select replacements that support our smart grid vision.
- **Technology risk awareness:** Suppliers in the smart grid technology arena are constantly enhancing their products. While PSE will design a flexible system that accommodates changes, many new smart grid applications will continue to evolve at an increasing rate, and may require PSE to replace or upgrade future investments more frequently than in the past.

Review of PSE’s Smart Grid Initiatives

PSE has been serving our customers with smart grid components for over 35 years – before the term “smart grid” was widely known. Our early experience allowed us to test technologies and learn many lessons about what would later become known as smart grid through a series of projects spanning decades (Figure 2).

Figure 2: PSE’s History of Deploying Smart Components



(See Appendix A for more information about PSE’s history of deploying smart grid components.)

The last two years have brought about a significant change in the way PSE is able to effectively manage electricity reliability and customer service through the use of more integrated systems. The following chart provides a progress report on the proposed activities, all of which have been completed or are moving forward as planned.

At-a-Glance Progress Report of 2015-2016 Proposed Smart Grid Implementation Plan

(As proposed in PSE's plan submitted to the Washington Utilities and Transportation Commission (UTC) dated Sept. 1, 2014.)

✓✓ Executed on plan	✓ Pursued plan with some changes	+ Plan on hold or cancelled for business reasons
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Information Technology	Status
Upgrade PSE's existing Meter Data Management System (MDMS)	✓✓
Develop an implementation schedule for a Distribution Management System (DMS)	+
Implement Supervisory Control and Data Acquisition (SCADA) using IP technology on all new substations and major substation rebuilds	✓✓
Complete a technology roadmap for migrating to an Advanced Metering Infrastructure (AMI), including accompanying system requirements and architecture	✓✓
Initialize PSE's Energy Trading and Risk Management (ETRM) System deployment over 2013-2016	✓

Customer Information and Energy Empowerment	Status
Roll out completed redesign of My PSE Account into the existing PSE.com	✓✓
Complete the next phase of enhancements to PSE.com online tools	✓✓
Continue to support customer adoption of small renewable generation	✓✓
Continue to analyze Plug-in Electric Vehicle (PEV) trends	✓✓

Electric Grid	Status
Install a transmission line switch and continue to roll out one to two automation schemes per year	✓✓
Continue to work with a large customer to gauge automation improvements that would enhance their electric reliability	✓✓
Continue the recloser installation program expansion on overhead circuits	✓✓
Install Supervisory Control and Data Acquisition (SCADA) switches in PSE's distribution substations	✓✓
Expand Remote Data Acquisition Device (RDAD) program in the Bellevue Central Business District (CBD), and determine the technology's next steps	✓✓
Define requirements for, evaluate, and select a distribution automation program.	✓✓
Implement Conservation Voltage Reduction (CVR) on three to six PSE substations before energy is sent to customers, thereby reducing customers' electric power consumption at the point of consumption on the customers' side of the meter	✓✓

(See Appendix B for more information about progress report details.)

With our experience in areas such as an early commitment to automated meter reading, self-healing transmission lines and utility-scale wind generation, PSE has been able to progress at a measured pace. We're expanding our operations network, sensibly deploying projects, and improving our operations, service, security and customer relationships.

PSE's Implementation Plan (2017-2018) and 10-year Roadmap (2017-2027)

As with its previous roadmaps, PSE's smart grid technology implementation plan continues to take into account the regional landscape and our overall approach to new technologies. Each project in Appendix B fits into our overall roadmap of where we see ourselves and our customers heading over the next 10 years. Our plan focuses on the business needs that will drive the adoption of smart grid technologies, and it also describes how we will support our customers as they plot their own paths into the world of smart grid. These plans may be adjusted as we learn from our current activities and pilots and the industry at large, and as our customers' needs and desires evolve. Our plans are also subject to resource and budget considerations, as well as technological changes and capabilities.

Over the next 10 years, PSE will continue to:

- Deploy two-way automated metering technology to refresh the aging legacy infrastructure and to enhance the customer experience and operational efficiencies
- Expand deployment of self-healing technology that automatically reroutes power during outages to improve electric system reliability
- Deploy grid-scale energy storage pilot projects and continue to research and evaluate emerging energy storage technologies
- Work with customers to develop and refine easy-to-use energy management capabilities and reporting tools/information, and general application of technologies
- Support customer energy needs/desires, such as electric vehicles and customer-owned power generation
- Upgrade and replace aging equipment and technologies as needed – for IT networks, back-end information systems and the electric system – with consideration to implementing a smarter grid
- Evaluate and selectively deploy other customer energy management pilots/programs

While pursuing our smart grid strategy, PSE will continue to put a strong focus on cybersecurity. PSE's goal is to apply the same level of due diligence across the enterprise to ensure risks are consistently addressed and mitigated in alignment with the rapidly changing security landscape. PSE utilizes a variety of industry standards to measure maturity as each standard approaches security from a different perspective.

As critical infrastructure becomes more technically complex, it is even more crucial for PSE to adapt and mature its cybersecurity practices and programs allowing the business to take advantage of new technical opportunities – such as smart grid technologies – while continuing to mitigate the risks. This requires constant evaluation of PSE's cybersecurity posture to ensure additional investments are properly identified and funded. In addition, we will need to continue fostering strong working relationships with smart grid vendors to ensure their approach to cybersecurity matches PSE's expectations and needs.

As smart grid technologies continue to evolve and our customers and the market present us with new smart grid opportunities, we will review, evaluate and potentially pilot projects or programs in the following areas:

- Electric vehicles
- Enhanced Demand Response and the ability to integrate traditional and non-traditional energy sources in the grid (such as wind and solar)
- Home intelligence and automation
- Storage and/or distributed generation to supplement peak power needs on the grid

The following table gives an overview of PSE’s plans in the areas of information technology, customer information and energy empowerment, and electric infrastructure. We have mapped each project to relevant smart grid functions as defined by WAC 480-100-505 (Figure 3).

Figure 3: PSE’s Proposed Smart Grid Activities Align with Relevant WAC 480-100-505 Smart Grid Domains

	EMS	MDMS	CIS	GIS	DMS	OMS	Substation IP Enhancement	Automated Metering	EIM / ETRM	PSE.com	Customer Energy Generation	Electric Vehicle	Distribution Automation	Transmission Automation	CVR	Grid Scale Battery Storage	
Smart Grid Function as Defined by WAC 480-100-505	The ability to develop, <u>store, send and receive digital information</u> concerning electricity use, costs, prices, time of use, nature of use, storage, or other information relevant to management of the electricity grid, utility operations, or customer energy use.	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓		
	The ability to <u>sense local disruptions</u> or changes in power flows on the electricity grid and to communicate such information instantaneously and automatically for purposes of enabling automatic protective responses or to inform the utility to make manual changes to sustain reliability and security or improve efficiency of grid operations.	✓		✓		✓	✓					✓		✓			✓
	The ability of the utility to deliver signals, measurements or communications to <u>allow an end-use load device</u> to respond automatically or in a manner programmed by its owner or operator without human action.		✓	✓		✓	✓		✓			✓	✓				
	The ability to use digital information to operate functions on the electricity grid that were previously <u>electromechanical or manual</u> .	✓		✓		✓		✓	✓			✓		✓		✓	
	The ability to <u>use digital controls to manage</u> and modify electricity demand, enable congestion management, assist in voltage control, provide operating reserves, or provide frequency regulation.	✓	✓	✓		✓		✓	✓			✓	✓		✓	✓	✓
	The ability to use two-way communication to <u>enable different customer contracts or programs</u> , such as real time prices or demand response programs.		✓	✓					✓	✓	✓	✓	✓				
	The ability to <u>manage new end-use services</u> to reduce operating or power costs, improve reliability, or improve energy efficiency, such as charging electric vehicles.		✓	✓					✓	✓	✓	✓	✓				
	The ability to use <u>real time measurement of power</u> generated from customer-owned power facilities to reduce operating or power cost, improve energy efficiency, or improve reliability.		✓	✓					✓	✓		✓	✓				
	The ability to use digital information to <u>improve the reliability or efficiency of generating equipment</u> in an integrated manner to improve flexibility, functionality, interoperability, cyber-security, situational awareness, and operational efficiency of the transmission and distribution system.	✓	✓			✓		✓	✓			✓					✓

The following sections outline PSE’s two-year implementation plan and 10-year roadmap, with projects categorized into one of three major fields. Additional information on specific individual smart grid components or projects is provided in Appendix C.

Information Technology

PSE is embarking on a number of projects (outlined below) to build, strengthen and improve PSE’s core information systems while increasing security and reliability of communication that supports the operation, management, control, and monitoring of energy. The benefits of these projects include improved outage detection and restoration, enhanced customer service/communication

capability, and improved billing and payment options. With these, PSE is creating the foundation to enable smart grid capabilities. With our integrated implementations of our CIS, OMS, GIS and EMS, PSE has a core foundation for the future.

Smart Grid Enablers

2017-2018 Plan

- Meter Data Management System (MDMS)
 - Consider integrating near real-time Web interface
 - Consider implementing OMS integration with AMR system
 - Implement initial AMI technology functionalities
- Customer Information System (CIS)
 - Continue with system improvement and greater process integration
- Gas Geospatial Information System (GIS)
 - Deliver PSE map information to mobile workers in the field
 - Delivery of an online map viewer for PSE LAN-connected users
- Distribution Management System (DMS)
 - Continue with evaluation of available DMS solutions in the market
- IP SCADA Enablement
 - Continue implementation of SCADA using IP technology at substation and generation facilities

10-year Roadmap

- Complete OMS-DMS-EMS-CIS-MDMS integration
- Implement and add elements (for example, generation) to the enterprise-wide GIS
- Complete integration of MDMS to outage and engineering applications
- Migrate substations that require back-up control-center communications to IP
- Continue extension of fiber optics cabling throughout electric system

Automated Metering

2017-2018 Plan

- Continue rollout of AMI network, back-end systems and processes, and a portion of AMI endpoints

10-year Roadmap

- Proceed on AMR-AMI conversion as appropriate

Energy Markets and Trading

2017-2018 Plan

- Continue participation in Energy Imbalance Market
- Monitor developments in ETRM solution options with an eye to a gas management system and a gas for power system

10-year Roadmap

- Complete implementation of integrated ETRM solution, including a power management system and integrated resource management analytics

Customer Information and Energy Empowerment

Customer adoption continues to be a key driver in PSE's deployment of customer facing smart grid technologies. For example, electric vehicles and charging stations, customer energy generation, demand response and home automation can all affect the grid at its most local level. As new customer installations grow and begin to increase peak load on our transmission and distribution systems, PSE will need to consider several smart grid capabilities to help manage and optimize the system – from timely access to data from the grid to customer programs such as demand response and load control.

Growing customer interest in energy management may drive the need for more easy-to-use energy management and reporting tools, better information through two-way automated metering technology, and other customer energy capabilities such as household energy usage or appliance monitoring and adjustment. Anticipating customer needs and desires will also require us to find new solutions for security and customer privacy. All of these facets will help smart grid technology balance energy delivery and load utilization.

Energy Use Information and Feedback

2017-2018 Plan

- My PSE Account – Continue work to improve overall usability of the site through back-end improvements and redesigns as needed
- PSE.com/Online Tools – Continue to improve upon personalized online energy management tools for customers to take better control of their energy use

10-year Roadmap

- Review and evaluate proposals for additional Web components and applications; consider the deployment of pilots and/or programs to learn the potential savings and value proposition to customers

Customer Energy Generation

2017-2018 Plan

- Anticipate and support continued rapid program growth
- Evaluate opportunity for pilots and/or projects involving smart meters and direct-to-customer-computer and smart phone messaging

10-year Roadmap

- Continue to monitor consumer and market changes and technology advances for program enhancements and/or changes

Plug-in Electric Vehicles (PEV)

2017-2018 Plan

- Evaluate electric vehicle charger program to gather updated information on vehicle charging locations and load curves specific to PSE's customers; compare these results with earlier studies, PSE's normal system load shape and renewable resources
- Continue efforts in assessing methods to evaluate PEV energy usage and demand, using PSE's meter systems and customer vehicle data, if available
- Continue to assess capabilities of "smart chargers"

10-year Roadmap

- Evaluate and deploy AMI end points as an alternative to SCADA assets
- Develop energy and demand forecasts based on already experienced adoption rates and needs
- Incorporate PEV loading and forecasts into T&D planning, and design standards where appropriate
- Scale a program in step with IT communications, meter rollouts and customer demand where the business case demonstrates overall benefit to customers and PSE

Electric Grid Infrastructure

Driven by our objective to provide safe and reliable service, PSE will continue to explore, evaluate and selectively deploy smart grid strategies. For each smart grid solution we consider, we will take into account the diversity of our service area – which could be places that are in the downtown core, suburban or rural – as well as the reliability challenges brought on by high trees and vegetation density in the service area. PSE will work to maintain appropriate cost/benefit ratios at each stage of the project.

Transmission Automation and Reliability

2017-2018 Plan

- Continue program to upgrade existing transmission automatic switch schemes as needed; these upgrades will be based on specific benefit, cost and available funding

10-year Roadmap

- Depending on project specific benefits and cost, as well as available budget funding, continue toward the goal of having supervisory control of all automatically controlled switches
- Continue to upgrade aging or older SCADA systems in transmission substations
- Based on cost/benefit analysis, selectively replace aging components with modernized equipment that will facilitate smart grid adaptability

Distribution Automation Projects

2017-2018 Plan

- Distribution Automation
 - Monitor newly deployed automation solution to gain performance data on which to plan expansion; expand DA capabilities to other locations within PSE area where the most customer benefits are expected
- Distribution Recloser Program
 - Continue expansion of the recloser installation program on overhead circuits, and evaluate the benefits of enabling recloser communication and monitoring capability
- Distribution Supervisory Control and Data Acquisition (SCADA) Program
 - Continue to upgrade the distribution SCADA on existing substations; select projects as either stand-alone projects or within Distribution Automation upgrades based on specific benefit, cost and available funding
 - Install supervisory control on feeder breakers at new and other selected distribution substations
- Remote Data Acquisition Devices (RDADs) Pilot
 - Monitor RDADs currently installed to locate circuit faults
- Distribution Automation - Bellevue Central Business District (CBD)
 - Implement switches in the Bellevue CBD area to facilitate remote switching
 - Plan for the automation of the Bellevue CBD switches
- Distribution Monitoring Pilot
 - Continue pilot program to deploy sensors on distribution lines to provide information about system performance for fault location and predictive outage analytics
- Conservation Voltage Reduction (CVR)
 - Implement CVR on three to six substations annually to increase energy conservation on selected distribution circuits by reducing line voltage at a substation and monitoring the end-of-line voltage with smart meters

10-year Roadmap

- Expand distribution automation in areas with high critical load and/or reliability concerns
- Continue expansion of recloser installation program and expand communications and monitoring capabilities depending on cost/benefit
- Continue expansion of SCADA use at distribution substations with the goal of providing supervisory control of the feeder breakers
- Depending on pilot results, deploy distribution-level sensors more broadly throughout PSE's service area
- Expand CVR program to appropriate locations where cost-effective projects will create energy savings by reducing customers' electric power consumption

For full details of PSE's two-year smart grid implementation plan and 10-year roadmap, as well as descriptions of smart grid technologies PSE has considered or is considering, please refer to Appendix C.

Conclusion

Smart grid technologies can provide benefits to both customers and utility operations through significant improvements in grid operations, reliability, energy production and customer service. These capabilities will modernize PSE's energy infrastructure, but will also require it to carefully consider how it deploys them to ensure a successful transition to more functional systems.

One key to successful smart grid deployment will be the prudent and systematic introduction of smart grid technology at each level of infrastructure: at the customer premises, in the electric grid and in PSE's information systems. Not only will this approach help to avoid system-wide interoperability issues, it will also aide PSE in understanding which technologies are most useful to and desired by PSE customers.

A second focal area for smart grid technology investment will be the maturity of the technology itself. Because smart grid technology is continually evolving, a prudent approach will include continued evaluation of smart grid technologies. These evaluations will ensure that technologies deliver anticipated benefits and results; that they follow industry standards; that vendors will continue to support and develop/improve the technologies over time; and that the technologies are cost-effective.

A third critical focal area will be the financial provisioning for smart grid technology investments. These investments must be balanced with the realities of rate schedules, cost recovery and the acceptance levels of customers before they are systemically deployed.

Finally, the role of the customer as ultimate beneficiary of smart grid products and services should not be understated or underestimated. PSE is in a service business, and the reliability and cost-effectiveness of the energy we provide to our customers enables them to operate their homes and businesses. Active collaboration and open communication channels to customers are important values within PSE, and are important components of every PSE project – smart grid or otherwise. By giving thought to each of these aspects, PSE aims to continue its own system improvements that lie within the domain of smart grid.

Glossary

Definition of Acronyms and Terms

AMI – Advanced Metering Infrastructure.

Ampere – Unit of electric current or a measure of the amount of electric charge passing a point per unit time.

AMR – Automated Meter Reading.

Applications – Hardware or software functions designed to perform single or multiple related and specific tasks.

Back-end information systems – Information systems that are invisible to the end user, but that handle a majority of the processing behind the transactions that the end user executes.

CAISO – California Independent System Operator.

Capacitor – A device for accumulating and holding a charge of electricity, consisting of two equally charged conducting surfaces having opposite signs and separated by a dielectric.

CIP – Critical Infrastructure Protection.

CIS – Customer Information System.

Charging station – A conveniently situated physical location where electric vehicles can be charged/recharged with electricity.

Conservation – Any reduction in electric power consumption resulting from increases in the efficiency of energy use, production, or distribution.

Conservation Voltage Reduction (CVR) – Reducing line voltage at a distribution substation from the typical 120 volts down to 117 volts (typical for residences) before energy is sent to customers, thereby reducing customers' electric power consumption at the point of consumption on the customers' side of the meter.

Control house – Is usually located at the substation and contains switchboard panels, batteries, battery chargers, supervisory control, power-line carrier, meters, and relays. The control house provides all weather protection and security for the control equipment.

Customer energy generation – Energy produced by a utility's customers (e.g. solar panels, wind turbines).

Demand Response (DR) – Managing customer consumption of electricity in response to supply conditions in an electricity grid.

Demand-side resource – Energy efficiency measures, demand-response, and other techniques that reduce the amount of power customers need (or "demand") in order to operate their homes and businesses. These resources generally originate on the customer side of the meter, whereas supply-side resources are generated and then transmitted (or "supplied") to customers.

Distribution Automation (DA) – The extension of intelligent control over electrical power grid functions in the electric distribution network to minimize outage time to customers. With distribution automation, the energy distribution network will automatically restore service to some customers when a fault occurs on the system. This greatly reduces the outage time experienced by some customers.

Distributed generation – Electric generation that is located close to the particular load that it is intended to serve. General, but non-exclusive, characteristics of these generators include: an operating strategy that supports the served load; and interconnection to a distribution or sub-transmission system (138 kV or less).

DMS – Distribution Management System.

DNP – Distributed Network Protocol.

DOE – Department of Energy.

DR – Demand Response.

EIM – Energy Imbalance Market.

EIS – Energy Interval Service.

EMS – Energy Management System.

Energy Interval Service (EIS) – An online energy management tool displaying 15-minute, hourly and daily energy that PSE provides to business customers participating in PSE’s energy efficiency grant and rebate programs.

ETRM – Energy Trading and Risk Management System.

Feeder or feeder circuit – An overhead or underground line or circuit that transports electricity from a distribution substation to homes and businesses (also known as a distribution line).

FERC – Federal Energy Regulatory Commission.

Fiber optic – Technology used in fiber optic cables that features the transmission of light signals via glass fibers for superior data transport.

Geospatial Information System (GIS) – A computer system for capturing, storing, checking, integrating, manipulating, analyzing and displaying data related to positions on the Earth’s surface. Typically, a GIS is used for handling maps of one kind or another.

HMI – Human Machine Interface.

Home Automation – The control of domestic appliances by electronically controlled systems.

Human Machine Interface (HMI) – A PC-based system that allows a human being to interact with computing and other mechanical equipment in a transmission/distribution substation.

Intelligent Electronic Device (IED) – A single device that can function as a programmable logic controller, a substation LAN node, an IED gateway, a bay level controller, a revenue class meter (non-certified), a power quality monitor, or a fault/event (waveform) recorder.

IRP – Integrated Resource Plan.

IT – Information Technology.

kV – Kilovolt.

Legacy system – A computer system that continues to be used either because the cost of replacing or redesigning it is expensive, or because there is no modern replacement system capable of performing the functions of this computer system.

Load balancing – The use of various techniques by electrical operations organizations to improve system performance and ensure current flow is the same on each of the three phases of a polyphase distribution system.

MDMS – Meter Data Management System.

MDW – Meter Data Warehouse.

NERC – North American Electric Reliability Corporation.

Net Metering – Technique where energy usage for a given residence or business is determined by netting the energy generated by the home/business for the grid against the energy from the grid that the home/business uses.

OMS – Outage Management System.

PEV – Plug-in Electric Vehicle.

Plug-in Electric Vehicle (PEV) – A vehicle that is powered entirely or partially by electricity with the ability to plug in to the electric grid.

PV – Photovoltaic.

RCM – Resource Conservation Management.

RDADs – Remote Data Acquisition Devices.

Recloser – An electrical circuit device that recloses an interrupted high voltage electric circuit system to restore power.

Remote Data Acquisition Devices (RDADs) – Devices installed on conductors that measure and report daily using cell phone technology an hourly snapshot of the amount of current present. It can also determine if a fault condition occurs and will immediately send a message to PSE’s System Operations.

Remote Terminal Unit (RTU) – A device installed at a remote location that collects data, codes the data into a format that is transmittable, and transmits the data back to a central station.

Renewable energy – Energy that is capable of being replenished (e.g., solar, wind) after it has been consumed.

Renewable resource – (a) Water; (b) wind; (c) solar energy; (d) geothermal energy; (e) landfill gas; (f) wave, ocean, or tidal power; (g) gas from sewage treatment facilities; (h) biodiesel fuel as defined in RCW 82.29A.135 that is not derived from crops raised on land cleared from old growth or first-growth forests where the clearing occurred after December 7, 2006; and (i) biomass energy based on animal waste or solid organic fuels from wood, forest, or field residues, or dedicated energy crops that do not include (i) wood pieces that have been treated with chemical preservatives such as creosote, pentachlorophenol, or copper-chrome-arsenic; (ii) black liquor by-product from paper production; (iii) wood from old growth forests; or (iv) municipal solid waste.

RTU – Remote Terminal Unit.

System Average Interruption Duration Index (SAIDI) – a widely accepted measurement of a utility’s reliability. SAIDI measures the minutes of sustained outages per customer per year. This metric does not include planned outages or outages lasting fewer than five minutes.

SCADA – Supervisory Control and Data Acquisition.

Self-Healing – Technology capable of automatically repairing the grid.

Smart Charger – A charger that monitors a battery’s resistance and voltage, and that adjusts charge delivery to maximize its efficiency and longevity.

Smart Grid – A term used to describe the integration of intelligent devices and new technologies into the electrical grid to optimize the system to a degree not possible with existing infrastructure.

Standards – Technical specifications that various industry vendors, companies and consortiums define and then agree to in order to guarantee equipment and software interoperability.

Substation – An energy generation, transmission or distribution facility where voltage is transformed from high to low or the reverse by using transformers.

Supervisory Control and Data Acquisition (SCADA) – A computer system for gathering and analyzing real-time data that is used to monitor and control substation equipment.

Switchgear – A combination of electrical disconnects, fuses and/or circuit breakers used to isolate electrical equipment.

T&D – Transmission and Distribution.

Transmission Automation – Intelligent technology that enables the transmission system to run itself without human intervention.

V/kV – Volt/kilovolt.

Voltage Ampere Reactive (VAR) – A unit used to measure reactive power in an alternating current (AC) electric power system. Reactive power is the loss of power in an AC power system, which is due to the production of electric and magnetic fields. Reactive loads dissipate no power, but they drop voltage and draw current, creating the impression that they actually do. As a result, reactive power is sometimes referred to as “imaginary power” or “phantom power.” Reactive power must be provided and maintained to ensure continuous voltage, so it is produced not for end-use consumption, but for system maintenance.



Appendix A

PSE's History of Deploying Smart Grid Components

PSE's history of deploying smart grid components dates back to before 1980. The following is a description of components identified on the historical timeline featured on page 12 of this report.

Pre-1980 to Present

Transmission Automation

Automation technology was first applied to PSE's transmission system in the 1970s, starting with transmission line switching that opens and closes automatically (without operator action) to isolate faulted sections of the high voltage line. The purpose was to improve reliability by first quickly sectionalizing and isolating the faulted or failed sections of the transmission line, and then restoring service to the rest of the line. In addition, some switches were enhanced with SCADA and "supervisory control," which enabled remote operation by the system operator.

Over time, "schemes" were designed that combined several automated switches with increasing logic and control, and the number of different switch operations and levels of sophistication steadily increased.

Today, PSE's 55-230 kV transmission systems include more than 90 automatic switch schemes, and many of the older schemes have been improved. All lines have remote monitoring and control, and nearly all are designed to self-heal.

Substation Intelligence Improvements

Substation SCADA: Prior to 1970, PSE substations had very few SCADA capabilities. A substation equipped with SCADA allows the system operator to view and control the status of its equipment. Limited information from the T&D substations was gathered over telephone lines, with larger substations having manned control centers onsite.

Substation circuit breakers were automated to trip and reclose in the case of a power failure, but the status was not known remotely. In the early 1980s, remote terminal units (RTUs) were added that allowed for the remote status and control of transmission system breakers and switches. During this time, SCADA could only allow slow speed communications to a central "host" computer, but there was no way to integrate the signals received from the field with the RTUs. By the mid-1980s, integration with RTUs began to occur with the systematic replacement of electro-mechanical relays and meters with intelligent electronic devices (IEDs). In 2009, PSE initiated a new phase of SCADA evolution by beginning the conversion of its SCADA analog system to digital format. Digital format facilitates communications between T&D network components for interoperability.

Substation Digital Relay Upgrades: From 1950-1985, PSE installed and used electro-mechanical relays in our T&D infrastructure. Some of these relays are still in service, but a majority of them have been upgraded to digital relays in a replacement effort that began in 1985 and still continues. Advantages of digital relays include multiple inputs, multiple setting groups, greater flexibility in setting selection and protection schemes, faster response times, time synchronization, fault distance logic/calculation, and remote status reporting, interrogation and programming.

Substation Capacitor Automatic Switching: In 2005, PSE began installation of automatic control to distribution substation capacitor units to respond to system needs and provide status information remotely to system operators. This provides more accurate and timely reliability support while increases the system efficiency.

Transmission Line Fault Locating: Prior to 1985, locating a fault on a several-miles-long transmission line consisted of a manual line patrol. This typically took several hours, and was often exacerbated by line access difficulties. Since then, we began installing digital relays that enable fault distance calculations in several locations on some of our transmission lines. The relays help calculate the

location of the fault, speeding up assessment and restoration. As we convert older electromechanical transmission relays to digital ones, this feature is a standard addition.

Substation Human Machine Interface: Because early substations had little automation and no remote status reporting or control, operators visiting the substations had to rely on panels that used incandescent light-bulb labels for system information. In 2000, a new Human- Machine Interface (HMI) was introduced as part of the newer substation control houses. HMI PCs and software collect status/loading information in a real-time mode with historical data available. The display allows a user to visually inspect the condition of the substation, and to perform local control as needed. The HMI allows for faster assessment of the substation by local personnel, and enables information verification between field and central operations in a real-time mode.

1983

Telecommunications Upgrades

In 1983, PSE began upgrading and integrating a telecommunications infrastructure that now provides connectivity to roughly 800 locations, including service centers, generating plants, electric substations, gas gate stations, and any other locations requiring communication. This infrastructure transports a wide variety of information, including voice, data, SCADA, alarm, security, protection, and radio. It consists of leased telephone services, including hundreds of circuits from over a dozen providers, and PSE's private network equipment, including approximately 600 miles of owned fiber optics lines and 46 microwave paths.

Key telecommunications upgrade milestones include:

- First Digital Microwave – Installed in 1983 between Mt. Blyn and Mt. Erie to increase capacity and reliability of communications to the Kitsap Peninsula
- First Fiber Optic Cable – Installed in 1984 between the Eastside Operations Center and Sammamish substation to facilitate substation control
- First TDM (time-division multiplex) Network Management System – Installed in 1997 to provide automatic diverse routing of communications circuits between approximately 10 sites
- First VoIP Phone System – Installed in 2003 in association with the new corporate office
- First Diverse IP Core Network – Installed in 2009 between the Corporate Office (Bellevue campus), 24x7 Operations Facility (Eastside) and Customer Access Center in Bothell

Today, PSE's communications are managed primarily through two types of systems, one IP and the other TDM. There are two IP systems, one for corporate data and one for energy control. The TDM system carries all non-IP communication, both analog and digital.

1985

Information System Upgrades

Between 1985 and 2000, PSE acquired or developed most of the back-end legacy information systems (e.g., CIS, EMS, components of an OMS and DMS) that supported PSE's business. From 2000-2009, PSE developed seven discrete, secure networks to serve as the communications backbone for PSE's gas, electric and information assets, and continued to enhance its back-end information systems to reflect PSE's evolving business needs. Recognizing that many of its information systems would not continue to be sustainable with new and emerging business needs, PSE initiated RFI/RFP processes as well as overall system and network architectural studies in 2008-2009. These studies helped determine PSE's future direction and system replacement/upgrade strategies, as well as its path for consolidating communications into one or two company networks under a virtual private network (VPN) structure. In 2009, PSE also began application of NERC-defined Critical Infrastructure Protection (CIP) standards; and completed and installed the data warehouse and reporting system that monitors customer energy usage.

1998

Automated Meter Reading Deployment

PSE began discussions of moving to an Automated Meter Reading system in 1995, and conducted three pilot programs with the technology over a three year period. The AMR system uses a one-way radio frequency transmission from the meter to report consumption data. After selecting a product, deployment ran from 1998 – 2002, at which time all but 70,000 meters were changed. The final phase to install AMR on those remaining 70,000 meters was completed during the summer months of 2006. Total automation today includes just over 1.9 million natural gas and electric meters.

1999

Customer Generation

PSE's support of customer generation programs began in 1999 with the Net Metering program, with 98 percent of customers generating energy from solar photovoltaic (PV) systems. The program grew slowly until July 2005. In 2005, the state of Washington implemented the Renewable Energy Cost Recovery Program, which is an incentive-based program where customers with eligible generation technologies are paid for all kWh produced. The purpose of the program is to develop a market for renewable energy systems and to promote the manufacture of these systems in the State of Washington. Incentives are provided from July 1, 2005, through June 30, 2020. PSE administers annual payments to these customers and recovers those funds from state taxes.

This program is also known as Production Metering and along with federal tax credits and falling solar installation costs has helped accelerate the adoption of customer generation. Utility bills provided to customers show both Net and Production Metering. These programs continue to grow, and based on past growth patterns, customer generation systems are expected to reach 4,500 by the end of 2017.

2000

Distribution Automation-Large Customer Campus

In the late 1990s, a large customer requested and paid the incremental cost for a more robust and reliable distribution system. The initial project consisted of installing SCADA switches at a select number of critical campus buildings. The project size has increased from 6 SCADA switches to 42 switches today. Through SCADA, PSE's system operator can remotely monitor and control the distribution system, and is alerted real-time through an alarm if an outage event occurs. The remote operation also allows the operator to open and close the switches in order to isolate the cable where the outage occurred, and restore power to the rest of the sections.

In the early 2000s, the system was enhanced to a "self-healing" system, again focusing on critical buildings. Over half of the campus SCADA switches are now automated with logic schemes similar to those used for PSE's transmission system automation. The logic schemes use the SCADA data to automatically detect an outage, isolate the problem section and restore power to the rest of the sections without operator intervention.

Transmission & Distribution Intelligence Upgrades

Over the years, PSE has been continually installing three phase reclosers on distribution feeders to reduce the impact of outages; in 2009, a more aggressive program was initiated to improve overall reliability. Additional communications reliability initiatives came online when fiber optics cabling upgrades were made at key transmission substations to increase reliability and meet growing network demand.

Home Comfort Control Pilot

PSE delivered the Home Comfort Control Pilot (HCC), a pilot to test new technical capabilities, enhance its relationship with customers, and explore platforms for future program offerings. One hundred five customers participated in the proof-of-concept pilot in which software and thermostat control technology was tested for curtailment events triggered by PSE.

Participants, notified of upcoming curtailment events messages on their thermostat screens, could override any event at the press of a button. Participants could also access their thermostats over the Internet to read and reset them. The pilot experiment proved HCC could be feasible and reliable. PSE initiated 41 successful events, setting back the participants' thermostats by 2° F or 4° F for two hours, across a range of morning, midday and evening peak demand time slots. Participants' energy use was measured against a control group of customers, and demonstrated load reduction for both electric and gas heat. There was strong participation in the events, with only 5.3 percent of participants overriding the events. Overrides were concentrated among a few customers.

While the pilot was successful in its proof of concept and customer acceptance, the technology was prototypical and following the project, the participating vendors decided to not commercialize the components. Commercial HCC deployment would have required major resource-intensive work to adapt PSE CIS systems. The equipment was dedicated only to forced-air heating systems, and other appliance control systems would have to have been developed and tested.

PSE.com

PSE launched its website, PSE.com, in 2000. In 2005, My PSE Account was added, which allowed customers to view their statements, leverage home energy tools to download energy use analyzers, see their previous days' energy consumption, and pay their energy bills online, all of which was made possible by PSE's deployment of AMR. Online bill payment was added in 2004, and in 2006, the website provided customers with a single user sign-on enabling them to manage their online payments and access PSE's energy efficiency programs and services and the energy tracker tool.

2001

Time of Use (TOU) Pilot

PSE designed and implemented a TOU pilot with 400,000 customers. The initial phase was the information phase where customers received information about their energy use during four time blocks: morning, midday, evening and economy.

In May of 2001, the second phase was implemented using TOU rates. PSE designed and implemented a TOU rate for its residential and small commercial customers. The rate involved four pricing periods aligned with the four time blocks in the information phase. The morning and evening periods were the most expensive periods, followed by the midday period and the economy period. Unlike most TOU rates, which typically feature significant differentials between peak and off-peak prices, PSE's TOU rate featured very modest price differentials between the peak and off-peak periods, reflecting the hydro-based system in the Northwest.

To keep the rate simple, there was no seasonal variation in prices. The second phase was launched during extreme price volatility, which later would become known as the California Energy Crisis. PSE also had the Conservation Incentive Program in place.

Customers participating in the information phase were placed on the TOU rate plan, with the ability to opt out to the standard rate if they so desired. There was no additional charge to participate in the rate. The rate was designed to be revenue neutral for the average customer. During the first year of the program, less than 0.5 percent of customers elected to opt out of the rate. Customer satisfaction with the rate was high. In focus groups, customers identified several benefits of the TOU rate besides bill savings, including greater control over their energy use; choice about which rate to be on; social responsibility; and energy security. PSE also provided a website to customers where they could review their usage in the four rate periods for the previous seven days.

Later in the year, the pilot was modified to be opt-in, and included a monthly fee to recover the cost to manage the data. With the additional cost, the high price volatility declining, and the price differential reduced to being relatively small, many customers saw little or no savings. As such, the pilot ended in November 2002.

Key lessons learned from PSE's TOU pilot program include:

- Customers do shift loads in response to a TOU price signal, even if the price signal is quite modest. According to an independent analysis, customers consistently lowered peak period usage by 5 percent per month, over a 15-month period;
- It is important to communicate clearly with customers about likely bill savings;
- Consumer education is important, and should be done in a variety of ways. A variety of means were used, including: advertising, letters, refrigerator magnets, a company website that provided a listing of load shifting activities and associated savings estimate, and a personal website to view their usage in the four time blocks;
- While most of the customers initially visited the website to view their usage, use of the Web dropped off early in the program as customers gravitated to simple and easy actions, as suggested by our customer education messaging: turn on your dishwasher after 9 p.m., for example, or do your laundry on Sundays.

Meter Data Warehouse (MDW)

In late 2001, PSE launched a project to implement a MDW. There was a large volume of energy consumption data available that was not being stored or used to its full potential. The MDW initially served as a storage facility for data. Between 2002 and 2008, the system was enhanced to include functions like validation, load profile, service order integration, diagnostic flags, outage, and customer presentment. Tools were also built for ease of use as an enterprise application. In 2010, the MDW was upgraded to a full MDMS, capable of handling the intricacies of a smart grid environment. These intricacies include the ability to accept multiple meter read files daily, enhanced outage reporting for end points and network equipment, read recovery capability, and Web services for real-time applications.

2003

RCM Program/Energy Interval Service

Prior to its adoption of AMR, PSE began offering its commercial and industrial customers the Resource Conservation Manager (RCM) Program. Through the program, the customer tracks and analyzes utility use (e.g., electricity, gas, water, and waste), and identifies potential savings opportunities. PSE offers training as well to assist the customer. The Utility Manager is database software that tracks and analyzes monthly utility data. When the program started, customers initially had to manually enter their monthly utility data. But by 1998, PSE was able to provide digital customer billing data as a service to its RCM customers for import into their Utility Manager databases. RCM customers often track data for multiple accounts or facilities, and many are responsible for hundreds of meters. Providing data in a digital format has enabled them to accurately track the performance of each site, and to identify conservation opportunities.

In 2003, with deployment of AMR, PSE expanded its program offering to include an Energy Interval Service (EIS). In contrast to the Utility Manager software, EIS provides access to 15-minute interval meter readings for compatible PSE electric meters; and hourly or daily meter readings for compatible natural gas meters the day after data is collected. This provides customers with an enhanced ability to track, analyze, and optimize their energy use.

Through this program, PSE supports customers in identifying and targeting low- and no-cost efficiency opportunities that can be immediately implemented in facilities. These generally come from organized behavioral changes, operational improvements and enhanced facility maintenance strategies.

2005

Renewable Energy

Since 2001, PSE has promoted the development of renewable energy through its Green Power Program, which offers customers the option to purchase electricity from renewable energy sources. In late 2005, PSE became the first Northwest utility to build, own and operate a large wind facility. Our Hopkins Ridge Wind Facility in Southeast Washington's Columbia County has been generating power since 2005. PSE's second, larger wind facility, Wild Horse Wind and Solar Facility in central Kittitas County, has been producing energy since 2006. In 2009, PSE expanded the Wild Horse facility and in 2012, completed Phase I of our Lower Snake River Wind Facility in southeast Washington.

2006

Conservation Voltage Reduction (CVR) – NEEA Pilot

PSE originally conducted its first CVR study on ten residential feeders in 1983. In 2006, PSE and 13 other Pacific Northwest utilities participated in the Distribution Efficiency Initiative (DEI) study, convened by The Northwest Energy Efficiency Alliance (NEEA). The DEI study was intended to quantify the effects of power consumption in relation to the applied voltage. Design and operational techniques were used to optimize the performance of a distribution system in order to achieve energy and demand reduction.

The DEI study was comprised of two independent projects: the Load Research Project and the Pilot Demonstration Project. The results of the study conclusively showed that operating a utility distribution system in the lower half of the acceptable voltage range (114-120 Volts) saves energy, reduces demand, and reduces reactive power requirements without negatively impacting the customer. The energy savings results are within expected values of one to three percent total energy reduction, two to four percent reduction in kW demand, and four to ten percent reduction in kilovolt amperes-reactive (kVAR) demand. Computer model simulations showed that by performing selected system improvements, between 10 and 40 percent of the total energy savings occurs on the utility side of the meter.

One of the main objectives of the DEI study was to look at different techniques for lowering the voltage without falling below the minimum acceptable level (114 Volts as defined by ANSI C84.1), and measuring the impact on demand (kW and kVAR) and energy. The Load Research and Pilot Demonstration Projects controlled the voltage for 24 hours (On days), and then the normal utility voltage (uncontrolled) was applied for the next 24 hours (Off days), alternating back and forth for the duration of the project. The actual energy savings for the project was 8,563 MWh, or 1.88 average megawatts (aMW) (8,563 MWh/No. of Hours On). If the DEI projects were in operation full time (instead of every other day) for an entire year, the annualized savings would have been 16,490 MWh.

Mobile Workforce

In 2007, PSE began deployment of ruggedized laptops containing encrypted laptop-resident databases, and using Voice over IP (VoIP) and IP communications in service trucks to allow technicians to digitally record start, stop and status of service calls over a secure virtual private network (VPN).

2009

Plug-in Electric Vehicles (PEV)

Recognizing that PSE's customers would be acquiring plug-in electric and hybrid vehicles in the coming years, PSE incorporated two converted plug-in hybrids into fleet use and is working with several municipal customers and research entities that have done the same. Using data collected from the project, PSE has developed estimates of expected energy needs, performed initial assessment of distribution impacts on select circuits, and performed some tests of effectiveness of curtailed charging. All of these studies determined that initial adoption of electric vehicles and plug-in hybrids would not have significant effects on PSE's energy needs or distribution system. Today, PSE has four demonstration vehicles in its company fleet. We are also participating on the State PEV Task Force and working closely with entities/partners working to site and interconnect public PEV charging infrastructure.

Demand Response

PSE's 2007 and 2009 Integrated Resource Plans (IRP) presented achievable estimated demand response capacity potential for residential, commercial and industrial customer sectors. Pilot programs for both commercial and residential demand response were launched in 2008/09. PSE's primary focus was to pilot load control during times of high peak loads, focusing on the customer communication needed, as well as on the information and incentives needed to motivate the customer to respond.

Residential Load Control: While participants were highly responsive to the pilot promotion and recruitment process, total enrollment in the pilot fell short of the original target. Explaining demand response and differentiating it from traditional energy conservation in the minds of residential customers was challenging. As a result of the pilot, PSE found residential direct load control (particularly in a winter peaking climate) was a challenging and complex undertaking, even with the most current technology available.

Commercial/Industrial Load Control: Experience gained in conducting the pilot has greatly facilitated PSE's recent planning and RFP process for a long-term commercial-industrial demand response program. Satisfaction of customers with their participation experience was high. Most indicated an interest in enrolling in a future demand response program offered by PSE. The average event realization rate of original estimated energy savings was 83 percent during winter and 140 percent during summer.

PSE intends to expand its experience with Demand Response to attain its Integrated Resource Plan target of a peak winter load reduction of 121 MW by 2021. To accomplish this and other potential secondary goals related to on-demand usage reduction, in 2016 PSE intends to solicit and evaluate bids for DR solutions.

Home Power Cost Monitor Pilot:

In 2009, PSE piloted the use of the Blueline (a third-party provider) Innovations Power Cost Monitor with 1,000 customers. The device works by having an optical sensor attached to the customer's meter to read the meter and wirelessly send a signal to an in-home display. The customer enters the utility rate and is able to see home energy consumption and costs in real time, peak energy consumption in a 24-hour period, and the effects of customer end-uses on energy consumption and costs. While PSE determined that challenges and limitations of this pioneering technology did not make it viable for continued, large scale customer use, customer feedback indicated information provided by the monitor led them to make energy-saving changes or improvements to their home or behavior.

2011

Savings & Energy Center

In April 2011, PSE launched a Savings & Energy Center on PSE.com. This energy-efficiency dedicated section of PSE's website was developed as the foundation for making more sophisticated energy management and self-service tools available to customers online, in support of the PSE's business drivers and customer research. The updated website offers an improved user experience,

with more intuitive navigation and new online tools to help customers understand and reduce their energy usage, such as CFL recycling location and efficient product retailer and dealer locator maps, and integrated social media tools and multimedia channels. Additional features include:

- PSE’s Interactive Rebate Finder, featuring dynamic rebate and promotion information for homeowners, single-family home builders and multifamily property owners
- Audience-specific subsites with updated content
- “Re-Energize” energy-efficiency rebates and offers splash page
- Fillable sign-up and info request forms
- Home and business energy use calculators
- Energy-efficiency video gallery
- Energy-efficiency events calendar

2012

Conservation Voltage Reduction (CVR)

Successful results of the 2006 NEEA CVR Pilot led PSE to move forward and develop an initial program to analyze 12 substations by the end of 2012, and then implement CVR on three substations by the end of 2013, and three to six more substations in 2014. The results of the 2006 study conclusively showed that operating a utility distribution system in the lower half of the acceptable voltage range (114-120 Volts) would result in reducing electric usage and demand and reactive power requirements on the customers’ side of the meter without negatively impacting the customer. The proposed substations were selected mainly for their residential loading characteristics. PSE’s participation in the NEEA CVR study showed the importance of a number of “thresholds,” which help to assure properly maintained customer voltage levels. These “thresholds” include phase balancing, power factor, and end-of-line voltage monitoring after the CVR settings are implemented to verify the model. Modeling the system and loads as accurately as possible, while understanding the limitations of these models, is an important aspect of successful project implementation and inclusion of this program in PSE’s IRP under distributed efficiency.

Energy Management System (EMS)

PSE upgraded its EMS in mid-2012 to meet evolving PSE operational requirements, to stay current with existing and future NERC & FERC Cyber Security Advisories, and to support future business needs. As a core foundational technology for the enablement of smart grid capabilities, this upgrade increased efficiencies at PSE by reducing manual processes and increasing system automation, both of which are improving PSE’s ability to avoid or quickly restore a transmission outage. Additionally, improved network and SCADA model data collection capabilities provide added safety for field crews by communicating better information about the status of grid equipment and devices.

Geospatial Information System (GIS)

As of 2013, PSE has completed its data migration of electric and gas legacy map and service card data into PSE’s new GIS. This provides a significant increase in functionality over PSE’s previous static mapping system. A GIS is a core foundational technology for the enablement of smart grid and allows more effective management and control of PSE’s gas distribution and electric network. For example, the system provides easier access to network asset location and characteristics, and enables PSE’s system to be managed and maintained more safely and effectively. It enables increased network reliability and greater levels of service to PSE’s customers.

Remote Data Acquisition Devices (RDADs) Pilot

In 2012, 60 RDADs were installed in 20 switch locations in Bellevue’s Central Business District to support a fault detection requirement for the underground network. This technology has the potential to aid PSE System Operators with normal operational switching and allow quicker response to faulted equipment by reducing the need for troubleshooting. As of 2014, PSE has installed 90 RDADs, with 60 located in the Bellevue Central Business District.

2016

Grid-Scale Energy Storage

In 2013, PSE began efforts to develop its grid-scale energy storage capabilities to provide working demonstrations of dispatchable stored energy within PSE's service area. In February 2016, PSE completed construction of a 2.0MW storage system in Glacier, WA. Energy storage has the potential to assist PSE with shaving peak demand, reducing outages by dispatching stored electricity, and providing system flexibility which can help balance electric supply and demand and ease the integration of intermittent renewable energy generation into the grid. For remote and vegetation-dense parts of PSE's service territory, a key use of energy storage will be as a means of providing backup power during grid outages.

Distribution Automation 2.0

Since PSE deployed its legacy Distribution Automation systems in the late 1990s, next-generation automation platforms have been developed that offer far greater flexibility and scalability. As of 2016, PSE has selected and is deploying a new distribution automation platform that uses software capable of providing switching solutions in the face of changing grid conditions. The addition of distribution automation to its suite of reliability improvement tools will provide greater automated system restoration when an outage occurs and positively impact customer reliability.

Energy Imbalance Market (EIM)

In 2015, PSE announced its intention to participate in the California Independent System Operator EIM. The market will replace wholesale electricity transactions occurring on an hourly basis with a new market and tools that provide access to a voluntary, liquid, within-hour market. With its entrance into the market, PSE will be able to dispatch its generation resources more efficiently to lower electricity prices for customers, access diverse regional generating resources, and promote renewable generation.

Appendix B

Progress on 2015-2016 Proposed Implementation Plan

This appendix provides updates on programs that were proposed in the 2012 and 2014 UTC reports and their status as ongoing projects, completed, or on hold.

✓✓ - Executed on plan	✓ - Pursued plan with some changes	+ - Plan on hold or cancelled for business reasons
Area/Proposed Project Details		Status
Information Technology		
Meter Data Management System (MDMS)		
Proposed: Upgrade PSE’s Meter Data Management System (MDMS) to the most current version. Status Details: The project was completed in Q1 2015.		✓✓
Gas and Electric Geospatial Information System (GIS)		
Proposed: Implement Gas and Electric GIS. Status Details: PSE implemented a GIS to assist in managing and controlling PSE’s gas and electric distribution networks. In 2015, PSE successfully upgraded its GIS to the newest version, which provides new QA/QC functionality among other enhancements. In 2016, PSE installed a map viewer application that offers improved capabilities to those users connected to the PSE network, and implemented a new interface between the GIS electric network and electric load modeling software.		✓✓
Distribution Management System (DMS)		
Proposed: Receive the next integrated product release for its legacy system in 2013; develop a project schedule for the Distribution Management System (DMS). Status Details: PSE elected to postpone installation of a DMS, and will seek a solution that supports a single OMS and DMS interface.		+
Substation Internet Protocol (IP)		
Proposed: Implement SCADA using IP technology for new or rebuilt substations. Implement SCADA at additional substations, especially those that do not meet NERC Reliability Standard EOP-008-01 requirements. Build out the Operation’s Network Distribution Tier. Status Details: PSE has had a successful test of EOP-008-01, and has installed and commissioned 54 IP Gateways to date.		✓✓
Advanced Metering Infrastructure (AMI)		
Proposed: Determine strategic direction for the future of our metering system. Work to gather requirements and build out procurement and implementation plans. Continue to refine the business case for AMI. Status Details: PSE has begun enacting its plans to replace its legacy metering technology.		✓✓
Energy Trading and Risk Management System (ETRM)		
Proposed: Replace PSE’s Power Management System in 2014/2015, and implement Integrated Resource Management Analytics in 2015/2016. Status Details: The ETRM technology road map and business case have been drafted, though the project was deferred due to integration requirements and other priorities. A project to replace the legacy Gas Management System (GMS) for Gas Trading has been funded for 2016, however.		✓

Area/Proposed Project Details	Status
Customer Information and Energy Empowerment	
My PSE Web Enhancements	
<p>Proposed: Redesign “My PSE Account” and migrate it into the existing PSE.com. This provides an authenticated user experience as well as enhancements and additions to a variety of customer self-service features designed to enable future mobile capabilities.</p> <p>Status Details: Project completion and go live for this project occurred in 2012. The project is complete, though PSE continues development and refinement of its MyPSE web services.</p>	✓✓
PSE.com Online Tools	
<p>Proposed: Continuous Improvement to PSE.com Online Tools</p> <p>Status Details: PSE has developed enhanced personalized tools to help PSE’s residential and business customers take better control of their energy usage.</p>	✓✓
Net Metering (Distributed Generation)	
<p>Proposed: Expand processes for supporting distributed generation customers</p> <p>Status Details: PSE’s Net Metering program has had an average annual growth rate over 50%. PSE has over 4,300 net metered customers that together represent 29 Megawatts of capacity. PSE continues to build out processes and support for more customers and larger interconnection projects.</p>	✓✓
Plug-in Electric Vehicles (PEVs)	
<p>Proposed: Monitor PEV trends, and use this data to conduct feasibility/impact studies with regard to the vehicles’ potential impact on PSE’s service area. Utilize fleet demonstration vehicles, and continue to provide interconnection support to customers.</p> <p>Status Details: Ongoing efforts have been maintained with respect to PEV studies, and the vehicles have yet to make a significant impact on system operations.</p>	✓✓

Area/Proposed Project Details	Status
Transmission and Distribution Infrastructure	
Transmission Automation and Reliability	
<p>Proposed: Review existing switching schemes and upgrade or replace aging schemes as needed.</p> <p>Status Details: Replaced aging switching schemes affecting the reliability on five transmission lines in 2014, and eight lines in 2015.</p>	✓✓
Distribution Automation – Large Customer Campus	
<p>Proposed: Work with customer to analyze and review the system serving large customer campuses, and identify distribution automation improvements that enhance their system reliability.</p> <p>Status Details: PSE is in the process of implementing a new DA platform that will replace the legacy automation system for this large customer.</p>	✓✓
Distribution Recloser Program	
<p>Proposed: Continue expansion of recloser installation program on overhead circuits. Continue investigating the benefits for reclosers with communications and monitoring capability.</p> <p>Status Details: PSE has installed a total of 657 reclosers on overhead distribution circuits to date, with 74 installed in the last two years. Fourteen reclosers were installed with communication for remote monitoring and control.</p>	✓✓
Distribution Supervisory Control and Data Acquisition (SCADA)	
<p>Proposed: Install SCADA in all new distribution substations. Continue progress to install SCADA improvements at the final 6 of 7 substations by 2016-2017, along with new distribution circuit breakers with supervisory control.</p> <p>Status Details: To date, PSE has equipped over 99% of its distribution substations with SCADA, with 97% possessing three-phase amp readings on breakers. 31% of its substations have supervisory control of some or all distribution breakers.</p>	✓✓
Remote Data Acquisition Device (RDADs) Pilot	
<p>Proposed: Evaluate additional RDAD deployments and assess communication protocols for a potential expanded deployment. Develop a roadmap to connect these devices directly into System Operator’s tools for daily use.</p> <p>Status Details: PSE has installed a web hosting service linked to an existing operations graphical interface to gather fault data in near-real time. This provides a potential path to support a broader deployment.</p>	✓✓
Distribution Automation in Bellevue Central Business District (CBD)	
<p>Proposed: Finalize a solution for SCADA switches in existing vault locations, set new construction standards for future installations, and replace load switches in key locations to manage outage restoration, facilitate automatic switching, and allow further segmentation or isolation of problems. Evaluate and select distribution automation program.</p> <p>Status Details: PSE has retrofitted 24 SCADA switches, and is currently integrating their functions into the EMS. PSE is working with the City of Bellevue to refine the long term design and operating principles to help site future retrofit switch projects. PSE also finished installing a fiber optic backbone to two CBD substations, and is looking to add communication equipment to an additional substation to increase flexibility and reliability.</p>	✓✓
Conservation Voltage Reduction (CVR) Pilot	
<p>Proposed: Implement CVR Pilot on three substations in 2013, two substations in 2014, three substations in 2015, and one to three additional substations by EOY 2016. Continue to implement CVR on three to six substations per year.</p> <p>Status Details: PSE has implemented CVR on six substations by year-end 2015. PSE’s plans to implement CVR on three to six additional substations in following years.</p>	✓✓

Appendix C

Details of PSE's Two-year (2017-2018) Smart Grid Implementation Plan and 10-year Roadmap, Including Descriptions of Smart Grid Technologies under PSE Consideration

PSE regularly considers how new technologies, including smart grid technologies, may contribute positive benefits to its customers and systems. A catalog of these technology considerations would span the industry and its vendors. PSE evaluates certain technologies in more detail, and those chosen as part of PSE's operations are discussed below.

The following plans may be adjusted as we continue to learn from our current activities, our customers' needs/desires, pilot programs, and the industry at large. Our plans are also subject to resource and budgetary considerations, as well as technological changes and capabilities.

Information Technology

To continue to meet utility and customer demands, and to anticipate the future of smart grid, PSE is embarking on a number of projects outlined below. These projects are being leveraged to either build or strengthen PSE's core information systems, while increasing security and reliability of data transport related to the operation, management, control, and monitoring of energy. The benefits of this major undertaking include quicker outage restoration, enhanced customer service and improved billing and payment options. Essentially, PSE has been working to create the foundation to enable smart grid capabilities.

Over the past two years, projects critical to building this foundation have migrated towards completion. These include PSE's upgrades to its CIS, OMS, and EMS systems. PSE is continuing to refine its analysis of options and business values for transitioning from our one-way AMR system to AMI's two-way standards-based communication technology. PSE will also continue its transition of telecommunications traffic to Internet Protocol (IP). With these systems in place, PSE has the foundational technology to enable new applications such as fault location, isolation, restoration and service restoration and voltage control for conservation. Moreover, these systems enable the capability to communicate specific information to customers through a variety of mediums like web and mobile devices.

As requirements evolve, PSE will continue to develop its systems architecture to ensure PSE's security, compliance and business requirements are met, and align with interoperability standards. With several core capability projects behind us, including a number of upgrades to our back-end information systems, we expect our smart grid maturity level to significantly increase over the next 8-10 years.

The development and objectives of these core application projects reflect both PSE's requirements and the maturity of vendor offerings. These major categories of information technology initiatives are aligned within a replacement sequence that takes into account which systems are most critical to replace or upgrade first, which systems are nearing the natural ends of their asset life cycles, and which systems deliver the greatest immediate value to our customers and critical business functions. Budgeting, funding allocation, and rate structure constraints and considerations are all equally germane to this assessment process as well.

Finally, PSE's information technology approach to the smart grid requires interoperability for systems, networks, and network end-point devices. With government and industry standards still in flux for both interoperability and security, PSE is taking a step-by-step approach to deploying integrated information technologies to the degree feasible at the time.

Project: Meter Data Management System (MDMS) Disaster Recovery (DR) Implementation

Project Description (including goal/purpose of technology): The purpose of the MDMS DR implementation is to ensure that the metering data processes are located in redundant locations / hardware and databases. This will ensure higher reliability and availability of meter data for customer billing and energy efficiency tracking as well as meter outage data for PSE's Outage Management System.

Accomplishments to Date: The budget for this project has been approved for 2016 and the project is currently undergoing testing. **Note:** MDMS-DR plans were postponed for approximately two years to allow for MDMS base system upgrades.

Lessons Learned: Through the design and implementation of this MDMS DR solution, PSE fully mapped out and optimized the interactions between its complex metering processes, and precisely assessed the criticality and interdependencies of each process. With this knowledge, PSE was able to apply state of the art data replication technologies to minimize the potential impact of an MDMS system outage and accelerate recovery of critical metering applications.

Next Steps: In 2016/17, PSE plans to implement the first stage of AMI capabilities with the MDMS.

Total Estimated Costs: \$0.4 Million

Benefits:

Dependability:

- The new system has the capability to provide continuous data through a DR event to the OMS system. This allows for a quicker restoration response and more reliable provision of information for billing and energy efficiency purposes.

Efficiency:

- Customer experience will be enhanced because of the high availability of data provided by the DR platform.
 - The ability to maintain access to AMR messaging that the OMS receives is improved during a disaster recovery event. This will enable field crews to have more up-to-date information on the status of restoration and energized lines.
-

Customer Impact: Continuous data availability to OMS can allow for quicker restoration response and customer bill inquiry response.

Project: Distribution Management System (DMS)

Project Description (including goal/purpose of technology): A DMS implementation will support and improve PSE's activities in both planning and directly operating the electric distribution network. The DMS will provide for direct monitoring and control of network elements in the field, measurement and analysis of power-flow and will provide a significant level of capability for switching automation. The DMS will allow PSE to create new internal models for substations, cabinets and other electrical assets within the GIS network model which is integrated with the asset data model in SAP and the electrical data acquired through SCADA.

Project Updates: PSE will be developing requirements for a DMS in 2017 and subsequently evaluating available commercial offerings.

Accomplishments to Date: Project startup has been delayed to allow time for product maturity from premier vendors in this space. PSE continues to monitor current offerings and developments in the DMS market and evaluate the business drivers and business need for this system.

Lessons Learned: PSE elected to postpone installation of a DMS until the availability of integrated OMS and DMS products. The delay also allows PSE's users to gain comfort using the new OMS tool implemented in 2013. Major commercial players in the OMS and DMS have consolidated and are driving new directions for their product lines.

Next Steps: PSE will start examining requirements for this system in 2017.

Total Estimated Costs: Additional implementation costs are to be determined.

Benefits:**Dependability:**

- Switching load flow analysis will allow for more frequent partial restorations, will shorten outage durations and improve SAIDI metrics and reduce lost revenue.
- Improved asset management and network planning will lead to a reduction in the number of outages in the long term, resulting in reduced outage costs.

Efficiency:

- System recommended clearance switching orders improve the productivity of System Operations personnel and shorten the outage recovery window.
- Switching steps for clearance automatically recorded as the crew executes the plan in the field for documentation and recordkeeping.
- Use of the training simulator mode allows for testing of the viability of alternate system configurations prior to switching operations and improves cold load pickups.

Safety:

- Faster development of switch orders, with safety documents, reference and switch plan library capability.
-

Customer Impact: The expected benefit to customers of the DMS is that outage frequency and restoration response will be improved.

Project: Substation Enhanced Communications (formerly Substation IP SCADA) Project

Project Description (including goal/purpose of technology): This project focuses on enhancing the communications between PSE substations and the Energy Control Center. The IP-based communications method increases the bandwidth over the legacy analog solution by two orders of magnitude and improves the availability of the entire SCADA system. The project allows PSE to meet the NERC Reliability Standard EOP-008-01, which requires Backup Control Center (BUCC) functionality within two hours. The mandatory compliance date of July 1, 2013 was met.

This project is ongoing and will continue to consist of several technology upgrades including incremental replacement of the existing analog SCADA communications infrastructure, telecom transport improvements, implementation of fiber isolation, battery backup and battery condition monitoring upgrades, installation of network cabinets, communication shelters, network routers & switches, upgrading the Multiple Address (MAS) master & remote radios, and the installation of a separate computer network to handle Operational data.

New Project Elements: PSE continues to expand IP SCADA through new SCADA additions and major rebuilds at substations.

Accomplishments to Date:

- PSE expanded the IP enablement to 80 substations, 24 pad-mount switchgear, and 4 pole-mounted reclosers.
 - PSE continues to extend fiber optic cabling throughout its electric grid.
 - Hardware and facilities standards were identified, including routers, remote terminal units (RTU), analog-to-IP converters, emergency power systems and new communications structures in 2010.
 - Build out of the Operations Network core was completed by the end of 2011, providing a platform for IP delivery.
 - Build out of the Operation's Network Distribution Tier in mid-2013.
 - PSE has used IP SCADA as part of the Snoqualmie generation upgrade project in 2013.
 - IP SCADA was used for the Baker River Hydro project upgrade in 2015.
 - IP SCADA was used for the Lower Snake River Wind Farm.
 - PSE used IP SCADA as part of the Snoqualmie generation upgrade project in 2013.
 - Developed an IP SCADA business case in 2016 to determine the rate in which legacy SCADA at all substations are upgraded to the new IP communications protocol.
 - Developed a Substation Network standard for all devices (SCADA, Meters, and Protective Relays).
-

Lessons Learned: IP SCADA requires storage planning and construction for additional equipment in existing substation buildings or cabinets that were not designed to keep this type of equipment. As with other smart grid projects, collaboration from an array of PSE employees from many different departments was necessary for successful implementation and coordination.

Next Steps:

- PSE will continue to implement SCADA using IP technology for any new substations (or those with major rebuilds).
 - Complete expansion of IP SCADA for all generation sites
 - First fully networked substation using PSE's Substation Network standard going into service in 2016.
 - By 2022, PSE will implement SCADA using IP technology at most substations on its electric system.
-

Total Estimated Costs: Total project costs are projected to be \$26 million through scheduled completion in 2022.

Benefits:**Dependability:**

- The system is designed to provide seamless SCADA control to critical substations communications with the loss of the primary Control Center.
- The system is designed to allow remote connection by technicians and engineers to facilitate faster restoration of services.

Efficiency:

- The IP SCADA project will allow for the elimination of traditional RTU equipment in the future, thus reducing the equipment footprint and need for copper wiring (mainly at new and rebuilt substations).
- The new systems will not require manual intervention to facilitate SCADA control from the BUCC.

Safety:

- Using fiber for substation communications eliminates the potential for dangerous high voltage issues between the substation and public networks that exists with copper.

Customer Impact: The substation IP SCADA project will improve PSE's ability to monitor and restore transmission outages.

Project: Advanced Metering Infrastructure (AMI)

Project Description (including goal/purpose of technology): Today, PSE has over 1.9 million AMR electric meters and gas modules installed that provide automated meter reads to support electric and gas billing, inform electric customer outage and restoration, and enhance customer engagement via a web portal. PSE deployed its AMR system over fifteen years ago and is approaching the end of the design-life of the AMR system. The obsolescence of PSE's AMR network and modules has prompted PSE to plan a path toward AMI to ensure that our meter reading operations are sustainable. PSE will be working to effect this transition over the next decade.

High-level strategic considerations within this project include:

- The obsolescence and end-of-life estimated for the current AMR meter infrastructure.
- The programs and services that PSE is interested in enabling with the AMI technology.
- The costs and benefits of the technology.
- The system architecture, network topology, interoperability of system components and the direction of the technology standards.
- The impact of cyber security requirements and business continuity requirements on capabilities.

Accomplishments to Date:

- In 2016, PSE initiated deployment of a new meter reading network to enable the use of AMI meters. PSE has also begun detailed planning for implementing the back-end IT capabilities and business processes to use AMI meters to provide automated meter reads to support billing, inform outage and restoration, and enhance customer engagement via a web portal.

Lessons Learned:

- Peer utilities deploying AMI systems have provided PSE with a wealth of lessons around customer engagement, technology capabilities, vendor engagement, and deployment approaches. We have noted the customer concerns about RF safety, privacy and meter accuracy with advanced meters, and studied successful approaches to addressing these concerns. PSE has continued discussions with peer utilities deploying AMI technologies to understand their approaches from a technological, economical and regulatory perspective. Finally, PSE has researched successful deployment strategies of several utilities.
- AMI technologies are likely to provide significant improvement for automated meter operations. However, building up the capabilities incrementally, in a phased approach, will allow PSE to ensure that the business strategy, the customer and organizational readiness, and the technology implementation are each successful.
- Selection of standards-based AMI communications reduces risks associated with a single-source of supply, while opening possibilities for interoperability for future applications beyond the conventional meter reading application.

Next Steps: PSE's next steps include installing an AMI network and head-end management software. In addition, PSE will be working to integrate the head-end management software to our back-office IT systems and to finalize the deployment strategy for the AMI electric meters and gas modules, to include an MDMS/SAP implementation. PSE will continue to refine both its business case on AMI as well as its ability to address technical considerations around migrating to AMI.

Total Estimated Costs: Costs will depend upon the scope and scale of deployment, the time horizon considered, and the enhanced customer and operational capabilities implemented. A full AMI deployment that replaces all of the electric meters and gas modules will exceed \$400 million.

Benefits: PSE continues to refine the benefits of AMI in detail, and would introduce these capabilities as they are considered and deemed suitable by stakeholders. AMI has provided the following proven benefits to other utilities that have deployed AMI.

Dependability:

- AMI will replace an aging AMR system which will ensure customers can continue to receive timely and accurate bills.
- Outage and restoration management are enhanced with AMI, allowing utilities to communicate to the electric meter to confirm restoration.
- The AMI network can be used to enable automation in the distribution grid for smart switching and device control to minimize the impact of planned and unplanned outages on the grid.

Efficiency:

- AMI will provide more and higher fidelity data and control capability that can be used to enhance energy efficiency offerings, build advanced analytics to pinpoint anomalies on the grid, and offer the ability to remotely or automatically perform operations that previously required field visits or manual actions. Furthermore, AMI can provide a foundation to implement demand response, dynamic rates and enable voltage conservation to more efficiently use energy and capacity.

Safety:

- Data gathered from AMI can provide added safety of field crews by enabling better information about the status of grid equipment and devices.
 - The use of remote disconnect switches enhance the safe delivery of services by not putting a field crewmember at risk of electric arc when disconnecting an electric meter.
-

Customer Impact: PSE is initiating this effort to address the age and obsolescence of the AMR system. To that end, customers will continue to receive timely and accurate bills. PSE aims to enable advanced AMI capabilities that would allow customers to experience a faster outage response, receive more accurate and granular information on energy consumption patterns to inform conservation actions, and choose from new products and services enabled by the meter communications. Some customers may experience improved accuracy in billing due to less estimation or due to a faster response to resolution when a meter issue occurs. Customer's energy data will continue to be collected in confidence.

Project: Energy Imbalance Market (EIM) Entrance

Project Description: In 2015, PSE announced its intention to participate in the California Independent System Operator (CAISO) EIM. The market automatically balances demand every 15 minutes and dispatches power plants to meet demand every 5 minutes with the lowest cost, secured constrained dispatch.

Currently, real-time power transactions are primarily conducted over the phone on an hourly basis. In contrast, EIM is an automatic, sub-hourly way to match resources to demand from multiple Balancing Area Authorities (BAA) across several states. This regional market of BAAs can increase the economic efficiency of the grid by providing this centralized, automated, and region-wide economic dispatch.

To effect its entrance into the EIM, PSE first completed a cost/benefit analysis and implementation agreement, and is currently undertaking implementation activities including system integration and testing, followed by market simulation before entering the EIM, which is slated for October 1, 2016.

Accomplishments to Date: Since announcing its intent to enter the EIM, PSE has successfully integrated its Full Network Model into the CAISO EIM. On April 29, 2016, the Federal Energy Regulatory Commission conditionally approved PSE's filing of Open Access Transmission Tariff amendments related to the EIM. PSE filed its compliance filing related to this Conditional Approval in May 2016.

Lessons Learned: PSE found that developing the Full Network Model is a critical component of CAISO entrance process, with IT and business collaboration just as important to success. PSE built upon lessons learned with NV Energy's and PacifiCorp's earlier EIM implementation. Additionally, the 24/7 operations environment of the EIM imparts an additional level of complexity to successful communication, engagement, and organizational change management of such a significant scale.

Next Steps: PSE intends to enter the EIM in October 2016.

Total Estimated Costs: PSE estimates startup costs will be approximately \$16.2 million, with ongoing annual costs of \$2 million.

Benefits:

Efficiency:

- A third party study estimates that PSE customers will realize annual savings between \$18 and \$30 million annually.
 - Efficient dispatch of PSE's generating resources, resulting in lower energy costs for our customers.
 - Enhanced system reliability.
 - Leverages geographic diversity of generating resources and electricity demand.
 - Promotes integration and higher utilization rates of variable energy resources.
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Customer Impact: Through the use of pooled resources and higher utilization of generation resources, the EIM can lower overall customer costs by requiring a lower reserve margin of generation capacity.

Customer Information and Empowerment

In the area of customer information and energy empowerment, PSE will continue using pilot projects to test the capabilities of new technologies that improve network operations, support information delivery to customers and empower customers to manage their energy use. Customer interest levels in energy management may drive the need for more robust energy management and reporting tools, while two-way automated metering technology can give customers detailed household energy usage information to make energy decisions. How these customer needs and desires evolve will drive our adoption of new solutions for security and customer privacy.

Within home automation, most home living spaces or home appliances could have some form of “smart home automation.” Potential characteristics of these technologies include:

- Smart appliances and thermostats that allow customers to set their energy consumption preferences
- Solar panels that collect energy which can be sent back to the grid and netted against home energy usage expenses
- Access to a Web portal that allows customers to view real-time information on energy usage
- Smart thermostats that can automatically adjust room temperatures based upon communications with the grid—and which can also display to customers what they are currently paying for power per kilowatt hour
- Smart appliances, such as washers and dryers, with on-board computer chips that can sense grid conditions and turn off or on as needed
- Plug-in Electric vehicles that can also act as back-up generators for homes and supplement the grid during peak hours, while they charge during low peak hours at lower costs
- Two-way smart meters that provide bi-directional communications between customers and the utility, and that automate the meter reading process

It will ultimately be up to customers to determine if or how they will take advantage of the levels of automation and energy management that PSE may offer. PSE’s goal is to equip its customers with the information and educational resources that help them to make informed decisions. To do so, PSE runs pilot projects that evaluate consumer comfort levels with new technology and measure the cost-effectiveness and quality of the technology itself.

On a final note, PSE is sensitive to customer concerns regarding protection of private customer information, and already has a detailed privacy policy to protect such information. As the company continues to evaluate and implement smart grid technologies and various customer-focused components, safeguards for customer privacy and data security will be taken into account.

Project: PSE.com Online Tools**Project Description (including goal/purpose of technology):**

PSE uses Web-based technologies to communicate information that empowers residential and commercial customers to make smart decisions regarding their energy use. PSE's AMR system provides data that allows customers to view their previous day's energy consumption online.

As part of its energy efficiency program, PSE also provides customers with information to help them make cost-effective energy efficiency investment decisions. This information encourages customers to participate in energy efficiency programs and services while simplifying the process to take action.

Today, PSE uses its website (PSE.com) to communicate with customers, in addition to brochures and bill statement inserts, covering several topics:

- Billing and energy use
- Tips on how to conserve and manage energy
- Information about PSE rebate and incentive programs
- Information and education on renewable energy, along with the promotion of PSE's energy-matching programs, which allow customers to purchase all or a portion of their energy from green energy sources
- Opportunities for customers to sign up for on-premise energy assessments
- Details on low-income assistance and tax incentives for energy-efficient products
- Goals and results of PSE's overall energy efficiency savings achievements

Detailed energy usage reports are available to customers via PSE.com, with customers able to access their household or business data in a secure environment. This is similar to the way the Green Button initiative gives customers easy access to their energy usage data.

PSE also provides whole building energy usage reports for building owners, operators, and their contractors by signing up through our web-service (MyData.pse.com). Building owners can use MyData to automatically upload their building usage data to Energy Star's Portfolio Manager or simply obtain the data to benchmark their building for their own energy efficiency projects.

Accomplishments to Date:

In 2014 and 2015, PSE invested in the development of enhanced, personalized tools within the myPSE account Energy Center to help PSE's residential and business customers take better control of their energy usage. These tools:

- Help customers understand the specifics behind their energy usage with interactive graphs and charts
- Show neighbor comparisons between residential customers
- Notify customers of higher than usual usage
- Provide new ways to encourage efficient behaviors, by suggesting personalized tips, tools, ideas and checklists, based on a customer's automated energy usage profile and self-assessment information

These capabilities complement the first phase and second phases of Web tools development and improved website organization launched in 2011, 2012 and 2013 (as outlined in PSE's 2012 Smart Grid Technology Report's Customer Energy Use Information and Feedback section and in PSE's 2014 Smart Grid Technology Report's Customer Information and Empowerment section).

Lessons Learned: Customers increasingly want sophisticated personalized tools to manage their energy usage and monitor their usage data. Continuous improvement of these tools is necessary as PSE's technology and customer experience expectations evolve. The MyData web-service is integrated with the ENERGY STAR® Portfolio Manager website as required by state law; therefore the architecture of Portfolio Manager's website dictated how our web-service was constructed to some degree. This integration requires ongoing coordinated maintenance with Portfolio Manager website upgrades or changes.

Next Steps: In 2016-2017, PSE plans continued investment in personalized online energy management tools, along with improvements in how these tools are promoted on PSE.com and how customers navigate to them.

Total Estimated Costs: As outlined in the Energy Efficiency Services Conservation Rider Saving Goals and Budgets, the customer online experience budget for 2014-2015 was \$1,318,630. In 2016, PSE plans to invest \$677,000 in its online tools and services.

Benefits:

Efficiency:

- PSE aims to enable and empower self-service energy management and community distribution networks.
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Customer Impact: This project focuses on empowering PSE customers with tools to track and manage their own energy consumption in a way that is both effective and intuitive. These online tools serve as one platform for a wide variety of its customers to make informed energy decisions.

Project: Plug-in Electric Vehicle (PEV)

Project Description (including goal/purpose of technology): The purpose of this project is to ensure that PSE is prepared for, and to encourage the arrival and adoption of mass-market plug-in electric vehicles. As of August 2014, PSE has operated a pilot program focused on collecting data on predominance of home charging and its potential long term contribution to peak energy demand curves, and how to potentially mitigate this peak impact. It is important to note that while PEVs have been growing rapidly in number in the Puget Sound region, the total number in PSE's electric service territory is still relatively small. As of April 2016, there were approximately 8,500 registered PEVs in PSE's electric service territory.

Accomplishments to Date:

2014-2016:

- Launched data pilot program to collect interval data collected from EV owners. As of May 2016, the program has approximately 1,100 customers enrolled, with ~850 metered to report interval usage data, and 40 customers equipped with data loggers to measure electric vehicle usage.
- Shifted from yearly to monthly tracking of PEV's in PSE's electric service territory.
- Collaborating with King County to develop pilot of electric buses in the Bellevue area.
- Continued installations of PEV charging infrastructure and use of electric vehicles in PSE's vehicle fleet.

2010-2014: Completed a comprehensive analysis of PEV sales forecasts, energy and peak load impacts, and financial implications based on available vehicle technologies.

- Distribution system study completed, with modest system impacts expected.
 - Demonstration vehicles are being used in the company fleet (Two Nissan Leafs, two Toyota Prius Plug-Ins)
 - PSE is working closely with entities/partners working to site and interconnect public PEV charging infrastructure.
 - Participation on the State PEV Task Force
 - Participation in the EV Project. Washington State data from the EV Project validated PSE's earlier forecasts for EV loads.
-

Lessons Learned: PEVs pose minimal impacts to generation and transmission in the short run. Impacts to the distribution system are small but significant, and likely manageable.

- In the long-run, the additional load and margin from PEVs is greater than the costs to prepare for and encourage this market, yielding a positive benefit for customers.

Lessons from the industry:

- PEV rollout by vehicle manufacturers has been slower than expected
 - PEV customer adoption has been lower than all forecasts, but it is too early to conclude what the long-term adoption will be. PSE remains optimistic that PEVs will be successful; even it remains a niche market for several years.
 - Smart-grid related efforts in this arena still appear premature. Automakers are reluctant to engage in vehicle-to-grid; other tactics to reduce peak load, such as TOU pricing are likely to be more cost-effective in the short-run.
 - Several studies have shown that Level 2 charging is more efficient than Level 1 charging.
-

Next Steps: PSE will continue to implement the Electric Vehicle Charger Incentive Program per electric Schedule 195, gathering information on vehicle charging locations and load curves that is specific to PSE's customer base. PSE will compare the information with earlier PEV analyses, PSE's normal system load shape, and renewable resource availability. Also under this program, PSE is comparing methods to monitor PEV energy usage, including monitoring through "smart chargers," using PSE's existing meter systems and data logging. In the same vein, PSE will continue to assess the capabilities and compatibility of "smart chargers" as they relate to PEVs.

Total Estimated Costs: Approximately \$400,000 for 2016 for program administration, data collection, and analysis. This estimate does not include incentives for residential chargers as proposed under PSE electric Schedule 195.

Benefits:

Efficiency:

- In significant numbers, the additional load from PEVs can enhance the efficiency and economics of our electric system, with greater results achieved by encouraging off-peak charging when our system has spare capacity. Increasing off-peak use may ease rate pressures under current flat rate structures.
 - PEVs reduce air pollution, particularly in urban areas.
 - PEVs reduce our State and country's dependence on foreign oil and can reduce our customer's exposure to volatile gasoline and diesel prices.
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Customer Impact:

- PEV customers benefit from lower fuel costs. In PSE's analysis, however, few PEVs are less expensive than a comparable
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internal combustion and/or hybrid on a total cost of ownership basis, despite substantial State and Federal incentives for PEVs.

- PEV customers benefit from fuel price stability and the convenience of not having to visit gas stations, though they may sacrifice range if driving a pure electric vehicle.

Project: Net Metering (Customer Energy Generation)

Project Description: At the end of 2015, PSE had 3,925 net metered customers. Most of these customers own residential solar photovoltaic (PV) systems. These customer generation systems have two PSE meters: a service meter which measures electricity both from the grid and to the grid; and a production meter which measures output from the system in AC. This project aims to ensure that customers are interconnected while meeting standards for safety and reliability.

Accomplishments to Date:

- PSE's Net Metering Program has grown at over 50% each year over the last 10 years, and it crossed over the 4,000 customer mark in 2015. All systems that can feed electricity into PSE's distribution network are known and mapped by location, technology and capacity.
 - New customer interconnection processes improvements for systems less than 100kW have been made to simplify customer applications and interconnection.
 - Application and interconnection process improvements for 100kW to 5MW projects are ongoing.
 - In 2013, PSE implemented new billing software that automated all aspects of Net Metering billing.
 - In 2015, PSE began researching software packages to automate the onboarding process of PV customer applications, and intends to roll out this software in 2016.
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Lessons Learned: As the number of customers grows, the need for automation and reduction of manual processes related to net metering grows. In 2013, PSE implemented new billing software on SAP that automated all aspects of net metering billing. Prior to this upgrade, every monthly bill of the net metered customers had to be adjusted by hand. One of the lessons learned is that with automation PSE employees are not examining every single bill on a monthly basis. While this saves money, the unforeseen downside is that we no longer have employees actively watching for billing issues.

Next Steps: Changes being implemented for 2016-2017 include introducing software which lets PSE's Net Metering team better track all timelines associated with the program, route projects more effectively through the company, and give customers visibility to project status. This workflow application will help speed the interconnection process, reducing customer calls and project timeline uncertainty.

Estimated Costs: For 2016, PSE's Net Metering program costs are approximately \$400,000.

Benefits: Most of the discussion of solar PV distributed generation's impact on the local distribution system is general and specific benefits must be evaluated on a case-by-case basis. Knowing the location of solar PV distributed generation systems, down to the circuit, allows us to determine the real benefits as the loads on these circuits grow. This will allow upgrades to be made with better knowledge and better results.

Customer Impact: In general, PSE's efforts to improve its own efficiency in facilitating distributed generation benefit the customer. We continue to look for cost-effective means to prepare for and manage a mass adoption of solar PV distributed generation systems.

Project: Demand Response

Project Description (including goal/purpose of technology): PSE's 2015 Integrated Resource Plan (IRP) presented achievable estimated demand response capacity potential for residential, commercial and industrial customer sectors. Based on the resource needs identified in the IRP, PSE is developing an acquisition process and strategy for demand response. A strategy for developing a cost-effective portfolio of demand response programs through 2021 will be completed in late 2016.

Accomplishments to Date: A market and technology assessment for fast demand response (<10 minute response) was conducted for high demand commercial and industrial customers in 2015.

Lessons Learned: In its market and technology assessment, PSE's primary focus was to evaluate the technical potential of various resources that could be provided with a fast demand response platform, and to determine the process and requirements for enablement of such a system at customer sites and with PSE's Energy Management System. The business case for a fast DR system was determined to be positive.

Next Steps: PSE will begin with capability comparisons between Demand Response solution providers, and use this information to carry forward with an RFP process.

Total Estimated Costs: Any future project costs will be dependent upon the size and scope of future DR strategy, as well as the solution or technology selected.

Benefits:

Efficiency:

- Demand response price-based programs will allow PSE to accurately portray the changing cost of energy production to its customers, who can then elect to adapt their consumption patterns and consume electricity when it is most beneficial to them.
 - Demand response will allow PSE to avoid generation investments and/or power purchases while reliably meeting peak resource needs.
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Customer Impact: Customers can save energy and money on their bills if they elect to change their energy consumption patterns in accordance with the incentives from a demand response program.

Electric Infrastructure

PSE's electric system forms the backbone of reliable energy delivery to customers, and must be made "smarter" to deliver the types of communications and services that customers expect. Critical factors considered in our two-year and future plans include:

- Upgrading and replacing aging T&D infrastructure and components, as well as supporting IT hardware and end-use systems, for greater system reliability and efficiency, and interoperability with future smart grid applications
- Managing the changes proactively with employees and with our customers, to ensure new and enhanced delivery systems are introduced seamlessly
- Planning, managing and deploying new technologies and solutions in a manner that is cost-effective, cost-efficient, and sensitive to the impact on energy rates
- Addressing the increasing (and changing) regulations under NERC, the organization which enforces regulations for the reliability of the bulk power system in North America, as they influence PSE's services.

Project: Transmission Automation and Reliability Program

Project Description (including goal/purpose of technology): The purpose of this project is to incrementally improve the smart transmission system by replacing aging infrastructure and technologies and adding new smart grid functionality of monitoring, remote operations and control, and automation. Automatic transmission switching schemes enhance system reliability and protection under different operating scenarios. Automatic switching sectionalizes and isolates faulted sections of transmission lines in order to restore service to distribution substations. When used in conjunction with supervisory control, automatic switching assists the System Operators in quickly determining the faulted line section and to mobilize crews to make repairs. Supervisory control enables the System Operator to continuously monitor the status (open or close) of the switches and to be able to remotely control their opening and closing. Automated switches with supervisory control have laid the groundwork for improved system reliability on the transmission system over the past thirty years. As load grows, the transmission system changes and the infrastructure ages, these legacy control schemes are updated or replaced.

Accomplishments to Date:

2014: Reviewed existing switching schemes and upgraded five aging schemes on five transmission lines to improve reliability.

2015: Upgraded an additional eight switching schemes found to be impacting reliability, and continued to review other schemes for reliability improvement opportunities.

Lessons Learned: It can take a long time to install and/or replace automatic and supervisory controlled transmission line switches. The length of time can depend upon several factors, such as planning and coordinating transmission line outages to minimize risk to the reliability of the transmission system. Installation times can also be affected by the need to coordinate potential outages with customers to minimize risk of a service interruption. For example, in the case of the 2011 Bellingham line project, PSE worked with an educational institution to align some of this work with the school's winter break.

Next Steps: PSE continuously reviews its transmission system for new automatic switch scheme opportunities, opportunities to improve existing schemes, and any needed upgrades or replacements of aging schemes. In addition, PSE is evaluating an improved transmission automation solution to better predict and isolate the location of a permanent fault on the line. This solution would aid in restoring the maximum number of customers automatically.

Total Estimated Costs: Annual project costs can depend on the number of improvements PSE undertakes in one year, and are estimated at \$1.5 to \$3 million annually for 2015-2016. PSE is still evaluating the potential costs of improved automation solutions.

Benefits:

Reliability:

- Automatic control of transmission line switches reduces customer service interruption duration times.
 - Supervisory control of transmission line switches enables better situational awareness for the System Operators, as they can readily identify whether a switch is open or closed, and also provides them with remote control of the switches.
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Customer Impact: Customers served by a substation with automatic control can expect an outage reduction from 60 minutes or longer without automatic control to less than a minute with automatic control, if they are located in an unfaulted section. The 60 minutes is the estimated time it takes to become aware of a problem, send a service lineman out to do a patrol, visually identify and communicate the problem back to the System Operator, and then to actually do the switching to isolate the faulted line section.

Project: Distribution Automation (DA)

Project Description (including goal/purpose of technology): The purpose of this project is to incrementally improve the distribution system reliability through Fault Location, Isolation and Service Restoration (FLISR). PSE implemented a new DA platform to allow for the expansion of FLISR on the distribution system. FLISR schemes enhance system reliability by quickly sectionalizing and isolating faulted sections of distribution lines in order to restore service to the unfaulted section of the line. When used in conjunction with supervisory control, FLISR schemes also assist the System Operators in quickly determining the faulted line section, providing precision locations to send crews to make repairs.

The installation of SCADA infrastructure has an additional benefit for service areas that have high density loads. Otherwise normal or emergency switching in these areas requires servicemen to access vaults under sidewalks with high foot traffic. To avoid potential pedestrian hazards, completed its original pilot to replace the seven manual switches for two circuits within the Bellevue Central Business District (CBD) with SCADA switches, and connect them to the EMS system via fiber optic cables. PSE has moved forward to install additional SCADA in accordance with its analysis of potentially useful locations.

Once the SCADA project is substantially complete and the system is fully operational, PSE will implement FLISR control schemes control that will analyze site data, isolate problems, and help to restore electricity to customers.

Accomplishments to Date:

- By the end of 2015, PSE completed the retrofit of 24 SCADA switches in the Bellevue CBD, which are being integrated into EMS. The fiber optic backbone system has been completed with connections to both North Bellevue and Lochleven Substations. At both substations, the locations for communications equipment and a power supply have been designed and installed to meet the project needs.
 - PSE investigated and specified an IT communications solution that meets network security requirements for field devices and will function for all known automation applications.
 - In 2015, PSE implemented the DA platform, an application that provides centralized execution of the FLISR schemes.
 - FLISR schemes have been developed and tested for 2 projects in 2015-2016, one of which is for a large customer who had a legacy DA installation which is now replaced.
 - In 2015, PSE established a test lab with the DA platform and several communication links and switch controllers.
 - From 2010-2016, PSE has installed 24 SCADA switches in the Bellevue Central Business District to ready the area for DA.
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Lessons Learned: Developing DA requires coordination across several departments that do not regularly collaborate on projects, so establishing clear roles and responsibilities of the team members is essential. Operators are unaccustomed to yielding control of the grid operation to automation and change management and training are required to ensure that System Operators are familiar with the technology and accepting of the changes. During installation of SCADA infrastructure, PSE recognized the need to place the SCADA switch control enclosures in an accessible location close to the distribution switch. Additionally, continued coordination with city planners and property owners is essential to making site retrofits feasible.

Next Steps: PSE has identified several candidate locations for implementing DA in 2016-18. Six additional projects are underway in 2016 with a similar number planned for subsequent years. PSE will also continue the replacement of switches in the downtown Bellevue “reliability ring” as project priorities are determined in order to monitor unloaded back up circuits for the management of outage restoration. PSE will also work to evaluate and select potential sites within the Bellevue CBD that could benefit from PSE’s Distribution Automation program.

Total Estimated Costs: Ongoing costs to install SCADA infrastructure in the Bellevue CBD were \$1.5 - \$2 million annually for 2015-2016. The new DA platform and two initial sites cost approximately \$1,000,000. Implementation costs for additional costs will vary depending on circuit configurations and additional hardware needed but are likely to range between \$200,000 and \$800,000 per site.

Benefits:

Efficiency:

- Much more real time distribution information is made available to operations and planning to optimize system performance.
- Distribution Automation automatically and quickly isolates the faulted part of the circuit and provides quick feedback that allows System Operators to dispatch repair crews to the right location to start the repair. While a non-automated feeder might require manual switching in the field to isolate the fault, on the automated feeder, the repair crew can start repairs immediately.

Dependability:

- In conjunction with automation, the SCADA can automatically detect an outage problem, isolate it, and restore power to the rest of the sections without operator intervention and considerably less time than a non-automated response.

Reliability:

- Due to both the automation and remote control capabilities, PSE expects to have less impact on traffic in downtown Bellevue, as each site will not need to be visited by a service lineman during outage events.

Customer Impact: When outages occur on circuits, PSE is able to isolate the fault and reroute the power through other feeds using this automation scheme. The restoration of power to the customer is completed in less than 5 minutes. Without such automation, the restoration could easily exceed 2 hours.

Project: Distribution Monitoring Pilot

Project Description (including goal/purpose of technology): PSE has begun a pilot project to deploy easily installed, relatively portable line sensor technology, combined with hosted data acquisition and analysis service that can detect, locate, analyze, and notify on-line faults and disturbances via cellular communication. This project's goal is to provide information about system performance on distribution lines, specifically for fault location and predictive analytics.

Accomplishments to Date: As of July 2016, PSE has installed 51 sensors on the three worst-performing circuits identified for the project. PSE distribution system planners have been trained on the use of a hosted website for monitoring system output, and PSE is working with the product developer to refine its own methodology for best applying the collected sensor data to system restoration practices and reliability project planning.

Lessons Learned: PSE is identifying line disturbances with the sensors, though it is still working to establish patterns and thresholds for taking proactive measures to address them. Additionally, the technology is easily installed, mobile, and has additional applications, including:

- Circuit load balancing
 - Power quality diagnostics
 - Model validation using a distribution grid analysis tool
 - "Poor man's SCADA" – the sensors provide limited remote monitoring similar to SCADA-enabled assets.
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Next Steps:

- Quantify benefits and/or potential benefits received for current applications based on initial findings.
 - Set up permanent fault notifications for the use of System Operators and Dispatchers.
 - Develop projects or maintenance work packages based on analyzed sensor data.
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Total Estimated Costs: Current pilot project costs are estimated at \$120,000.

Benefits:**Efficiency:**

- The sensors can report permanent fault events and approximate location in near-real time, potentially preceding PSE receiving the first customer call indicating that an outage had occurred. This could lead to more efficient dispatching of resources and reduced outage durations.

Reliability:

- Reduce outage duration by providing quick fault identification and location information for faster restoration efforts.
 - Reduce CMI by proactively identifying line disturbance patterns so preventative maintenance actions can be taken prior to a sustained outage and/or customer complaints.
 - Help identify failing or mis-operating equipment prior to its total failure.
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Customer Impact:

- Potential to avoid outages through targeted proactive maintenance efforts.
 - Potential to reduce outage durations by assisting in identifying a fault's location.
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Project: Distribution Recloser Program

Project Description (including goal/purpose of technology): Most utilities pursuing significant reliability improvement on the distribution system, including PSE, install three phase reclosers on the distribution system. Reclosers interrupt faults and re-energize the line after a short waiting period. If the fault is temporary, this will allow the cause of the fault to be eliminated. If the fault is permanent, the recloser will “lock out” and remain open after a preset number of operations. These devices dramatically reduce the impact of outages to customers on the feeder by avoiding the station circuit breaker locking out and interrupting service to all the customers on the feeder. With reclosers installed, fewer than half of the customers served by the feeder will be impacted by an outage.

PSE has about 657 reclosers installed on its system. In 2009, PSE initiated a Distribution Recloser program to install more reclosers on the system with the goal of having at least one recloser on every overhead circuit where customers would benefit from the installation. Most of these reclosers operate autonomously in response to sensed conditions and have no remote monitoring or control capabilities.

In addition, PSE will be evaluating and piloting line reclosers with remote monitoring and control capabilities. Fourteen of the 657 reclosers on our system were installed with SCADA control and monitoring. These SCADA reclosers can be incorporated into a DA scheme with minimal retrofit required. Also, it is anticipated that outage duration will be reduced for customers when PSE’s System Operators can remotely operate the SCADA reclosers.

Accomplishments to Date: At the end of 2015, PSE had installed 657 reclosers on overhead distribution circuits. During the past two years from 2014 to 2015, 89 additional reclosers were installed.

Lessons Learned: The installations of reclosers have helped reduce outage duration for some customers. The biggest challenge for SCADA reclosers has been communications feasibility. Future projects should have a feasibility review by PSE’s Telecommunications Department that includes a site survey to determine the best communications solution for the site. From an operations perspective, PSE recognizes the positive impact SCADA control of reclosers has on its system, and further consideration should be given to integrating these and other SCADA-enabled devices into the new Outage Management system.

Next Steps: In 2016-2017, PSE will continue the expansion of the recloser installation program on overhead circuits. PSE will also continue evaluating the benefits for reclosers with communications and monitoring capability.

Total Estimated Costs: Approximately \$5.45 million was spent from 2014 to 2015 to install reclosers on the overhead distribution circuits, and PSE plans to spend approximately \$1.55 million per year in 2016 and 2017 to continue its pace of recloser installations.

Benefits:

Reliability:

- The outage duration for some customers will be reduced with the installation of the reclosers.
- For the reclosers with communication, the anticipated benefits include faster response time and restoration time due to instantaneous notification of recloser operations, and the ability to restore an outage remotely after the line has been patrolled and cleared.
- Reclosers are a key component of a DA scheme so the existing footprint of this technology can be leveraged as PSE brings automation to the distribution grid.

Dependability:

- There are system planning benefits from the information received. The three-phase ampere data from the reclosers allows for better system modeling and decision making.

Safety:

- Safety benefits may be achieved by allowing System Operations to turn off reclosing and activate the Hot Line Work Switch (HLWS) for system work, or even open the recloser for an emergency situation.
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Customer Impact: The outage duration will be reduced for some of the customers on the circuits with reclosers.

Project: Distribution SCADA Project

Project Description (including goal/purpose of technology): Supervisory Control and Data Acquisition (SCADA) is a system used to monitor and control substation equipment. Key information, such as circuit breaker status and transformer loading, can be obtained and transmitted to PSE's Operations Center almost instantly. With SCADA in the substations, crews do not need to be on site to obtain information. During storms and other outage events, this instant access to circuit breaker status (open or closed) speeds restoration efforts and reduces inefficiencies. In addition to circuit breaker status and transformer loading information, PSE's implementation of SCADA often includes the following:

- Monitoring the individual phase loading of the distribution circuits. This information is very important in order to maintain proper load balancing. Since this information is logged and stored on computer systems, it can be used for system planning studies, such as load analysis and simulation modeling.
 - Automatically integrating reactive power control at substations that have shunt capacitor banks. This can reduce system losses and reactive power penalties paid to the Bonneville Power Administration.
 - Adding automatic status and control to the 115 kV transmission switches that are typically on either side of the tap or "loop-through" going into the substation. When the 115 kV transmission line faults, the damaged section of line can be isolated by automatically opening a switch, restoring service to substations in seconds.
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Accomplishments to Date: PSE has been installing the SCADA system in the distribution substations over the years to better monitor substation equipment and its distribution system. 99% of PSE distribution substations have SCADA, 92% have three phase amp monitoring, and 23% have supervisory control of some or all distribution breakers.

Lessons Learned: The 24/7 data reported from SCADA provides system planners with information used for everyday planning – not just peak-load related planning. This information is used for load, reliability and outage studies.

Next Steps: For all new distribution substations, PSE is installing SCADA to operate and control substation equipment as well as monitoring the equipment. By the end of 2016, 100% of distribution substations will have three phase amp monitoring. In 2017, PSE will focus on bringing SCADA control enhancements to distribution substations.

Total Estimated Costs: PSE's annual budget for implementing this system is averages \$1.8 million per year.

Benefits:

Dependability:

- Projects funded by this program are identified with an overall benefit of improved system reliability through a reduction in outage duration and improvement in SAIDI.
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Customer Impact: Customers will experience improved reliability.

Project: Remote Data Acquisition Devices (RDADs) Pilot

Project Description (including goal/purpose of technology): The purpose of this project is to remotely determine the status of the distribution system through the use of fault sensors. RDADs report back to the system operator every day with hourly load data and daily peak load to aid in normal switching operations, and help System Operators determine where a fault occurred. This will aid PSE System Operators with normal operational switching and allow quicker service response times to faulted equipment by reducing the need for troubleshooting.

Accomplishments to Date: PSE evaluated a first generation of fault sensors, but found they did not capture meaningful data that could be used for planning and operational purposes. The sensor provider took PSE's input (as well as input from other utilities) and developed a second generation of sensors that give hourly load readings. They also integrated Verizon cellular technology into the units, allowing PSE to work with a preferred communications provider.

PSE has determined that the second generation RDADs could be supported by its EMS. The decision was made not to connect to the PSE system until the new DMS system is developed, and an alternative solution to use a web hosting product was examined and selected. PSE currently has 96 first generation RDADs installed, including 60 in the Bellevue Central Business District.

In 2014, a redesign allowed the RDAD to remotely configure via direct DNP3 communications, which will have the capability to give current information in higher resolution. The device uses newer cellular technology that should allow it use in more of PSE's service territory. PSE installed Grid Advisor, a web hosting program that links RDAD data with existing graphic interfaces to provide more granular system data in near-real time.

Next Steps: PSE is evaluating additional RDAD deployments, and is assessing which communication protocol would be the most efficient mode for a potential expanded deployment. PSE is also developing a roadmap to connect these devices directly into System Operator's tools for daily use, completing the original vision for this project.

Total Estimated Costs: \$3,500/year for the existing system for 2015-2016 and an estimated one-time cost of \$125,000 to integrate the next generation software into PSE's processes.

Benefits:**Efficiency:**

- The RDAD installation program will help optimize PSE's distribution system with load data on various segments of the feeder system.
- It will also reduce the duration of a circuit outage by reducing the amount of equipment to be inspected.
- This equipment is used in existing switchgear without any additional visual impact to the customer's site.

Project: Conservation Voltage Regulation (CVR)

Project Description (including goal/purpose of technology): Conservation Voltage Reduction (CVR) is the practice of lowering the feeder voltage at the substation and line regulators in order to conserve energy on customers' side of the meter without impacting the customers. PSE traditionally has set the feeder voltage within the mid- to higher- range of the American National Standard Institution (ANSI) standard. However, a study completed by the National Energy Efficiency Association (NEEA) in 2007 on two of PSE's substations and eight other regional utility substations has confirmed the economics of implementing CVR where the feeder loads portray particular characteristics. This has led PSE to move forward and implement CVR on substations with mainly residential loading and incorporating it into its Integrated Resource Plan under distribution efficiency.

Accomplishments to Date: By the end of 2015, PSE implemented CVR at six substations. The CVR process involves using a system modeling tool, phase balancing, monitoring AMI meter voltage data at the end of line voltage, adjusting the Load Tap Changer controller and system monitoring.

Lessons Learned: PSE's participation in the 2007 NEEA CVR study showed the importance of a number of "thresholds" which help to assure properly maintained customer voltage levels. These "thresholds" include phase balancing, power factor, and End Of Line (EOL) voltage monitoring after the CVR settings are implemented to verify the model. Modeling the system and loads as accurately as possible while understanding the limitations is an important aspect to successful implementation of the project.

Other lessons learned revolve around monitoring the system and making adjustments to the CVR settings as needed to ensure our customers continue to receive great power quality. Using AMI infrastructure for the end of the line metering proved to be the preferred method for EOL voltage monitoring. The energy savings CVR provides helps to lower both PSE customer bills as well as avoids or defers PSE capacity improvements. These substantial costs savings could be captured more broadly on suitable circuits with a complete AMI deployment.

There were a few scenarios with implementing CVR on the Mercer Island substations where a customer with an abnormally long service or a heavily loaded transformer noticed a lower operating voltage. The solution for this is to either upgrade the service transformer to a larger one or connect the customer to a closer transformer. Overall, implementing CVR on Mercer Island substations has verified the benefit of phase balancing and the need for system monitoring.

Next Steps: PSE will continue to analyze candidate substations to determine the most effective locations of future CVR locations, applying lessons learned from their deployment to future CVR roll-outs.

Total Estimated Costs: Basic CVR enablement costs approximately \$30-50,000 per substation under normal circumstances.

Benefits:

Dependability:

- Applying the CVR-specific method of Line Drop Compensation (LDC) will minimize the End of the Line voltage fluctuations, as well as generally decrease the system Volt Ampere Reactive (VARs).
- Phase balancing improves the health of the system by decreasing neutral current and minimizing losses.

Efficiency:

- Implementing CVR will increase conservation on selected distribution circuits by reducing line voltage at a distribution substation before energy is sent to customers, thereby creating energy savings on the customers' side of the electric meter. PSE will benefit from improving distribution efficiency by receiving energy savings, decreasing the peak demand, and the decrease of system losses.
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Customer Impact: Customer energy consumption will decrease and the savings will be realized on customer bills. The lower voltage should go unnoticed by customers since it is actively monitored and maintained within the ANSI standard.

Project: Grid-Scale Energy Storage

Project Description (including goal/purpose of technology): PSE recently completed construction of a 2.0MW/4.4MWh grid scale energy storage system in Glacier, WA (Glacier Battery Storage Project). The purpose of this project is a working storage system for dispatchable energy grid-balancing, outage mitigation, and other key services related to grid reliability and operation. It also builds the capability for PSE to automatically dispatch the system from PSE's control room.

PSE constructed the facility adjacent to PSE's Glacier substation and interconnects to the "Glacier-12" distribution (12.47 kV) circuit. Commissioning and testing completed using a load bank and proved that the system can work in both grid connected (Current-source Mode) and islanded (Voltage-source Mode).

As a part of the Glacier Project, PSE worked to promote a standard called Modular Energy Storage Architecture. This effort is focused around building out a communication and controls protocol standard within the energy storage supply chain for simpler and more economic cross-utility integration.

Accomplishments to Date: In February 2016, PSE successfully charged and discharged the Glacier Battery Storage Facility to the PSE grid for the first time. This symbolized the beginning of the startup phase of PSE's first battery storage project. The project construction took place from approximately September 2015 – March 2016. Commissioning and online testing took place between February – April 2016, and the facility was tied into PSE's operational control in April 2016.

Plans for Glacier substation upgrades to allow for the full discharge (>300 kVA) are underway with design completed and construction underway. The plan is to add a circuit switcher and high side sensing (CT/PT Combo) from May – August 2016. This substation rebuild will require an outage, thus requiring PSE to mobilize the 55 kV mobile substation to feed power to the town for the 2-3 month construction period. Once completed, the Glacier Battery Storage Project can begin operational testing (PNNL Use Case Testing) as part of the Washington State Department of Commerce CEF (Clean Energy Fund) Grant requirements.

Finally, plans are in place to install sectionalizing distribution reclosers to the Glacier-12 circuit to allow for circuit sectionalizing and thus battery-powered islanding in the case of a power loss on the transmission system. PSE plans to have this installed by August 2016 to be prepared to run the Automatic Islanding Sequence in time for the upcoming 2016-17 storm season.

Lessons Learned: PSE has many lessons to take away from the development, design, and construction of battery storage. Examples include design details and interfaces between PSE and the battery supplier were unclear and required some additional field work to achieve the design intent. In addition, the project's complex site acceptance testing required an extended period to retest capabilities as PSE made changes to system. Challenges were further compounded due to the remote location of the Glacier site, and the lack of utility infrastructure that required some unique designs to make the project succeed.

Next Steps: PSE will complete the Glacier substation upgrades and approve the Glacier Battery Project for full discharge and PNNL testing. Once the results are compiled for all the utilities and their respective CEF1 projects (Avista, Snohomish County PUD), PSE plans to operate the Glacier Project based on recommendations from the testing results.

Total Estimated Costs: PSE estimates a total project cost of \$11.3 million for the 2.0 MW Glacier Battery Storage Project. Accounting for the \$3.8M in Commerce funding, PSE's portion is currently estimated at \$7.5M.

Benefits:

Dependability:

- Outage mitigation. The storage system will be used to provide backup power during outages.

Efficiency:

- By dispatching the storage system like a small peaking plant, PSE may defer the need for new generation capacity.
- Flexibility/Ancillary services. By injecting and withdrawing power from the grid, energy storage can help balance supply and demand, which becomes increasingly necessary with increased penetration of renewables. The battery can shift from charging to discharging within 1/20th of a second with no issue, which is drastically different from rotating generators. This service can also reduce wear and tear on other generating units that are currently used for this service.

Customer Impact: The energy storage projects are initially designed to support either areas with frequent line outages or distribution systems that are approaching full capacity. Through the use of grid-scale energy storage, PSE aims to enhance the reliability of these communities through an “islanding” capability. In the event of a transmission-related outage, the stored energy will act as a short-term backup, providing 2-9 hours of electricity while the downed line is being serviced.