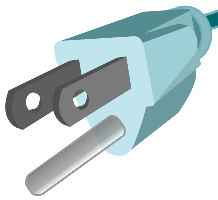


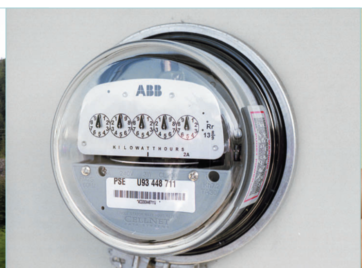
Puget Sound Energy

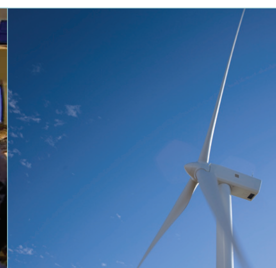
Smart Grid Technology Report

PUGET SOUND ENERGY

Sept. 1, 2010

Filed pursuant to WAC 480-100-505(3)(a)





Executive Summary

In 1998, when Puget Sound Energy (PSE) began implementing automated meter reading (AMR) – an important smart grid component – few were talking about "smart grid." At that time, PSE recognized that AMR technology would improve the way we operated and deliver greater value to our customers. Similarly, when PSE began building an automated transmission system over three decades ago, it was driven by the need for enhanced real-time monitoring and system visibility for its operators as well as improved reliability. Today, this self-healing transmission system is considered a smart grid component.

The Renewable Energy Center at PSE's Wild Horse Wind and Solar Facility in Kittitas County

Since then, PSE has also become a national leader in renewable energy technologies commonly associated with smart grid, with three wind facilities currently in operation or under construction in Washington state. Over the years, other "smart" components have been implemented, driven by objectives to improve service, reliability and efficiency; enhance safe operations; and support customers in managing their energy.

Currently, PSE is actively engaged in many projects that improve system reliability and provide more information and choice to customers. For example:

- Our automated meters collect energy usage information that enables customers to check and manage their monthly energy usage via the Internet;
- Demand response pilot programs allow customers to participate with the utility in reducing peak energy demand, which helps reduce overall stress and congestion on the grid;
- More than 600 residential customers have grid-connected solar and wind systems allowing them to generate their own power and supply excess energy back to the grid;
- Automated transmission and distribution (T&D) systems improve service reliability.

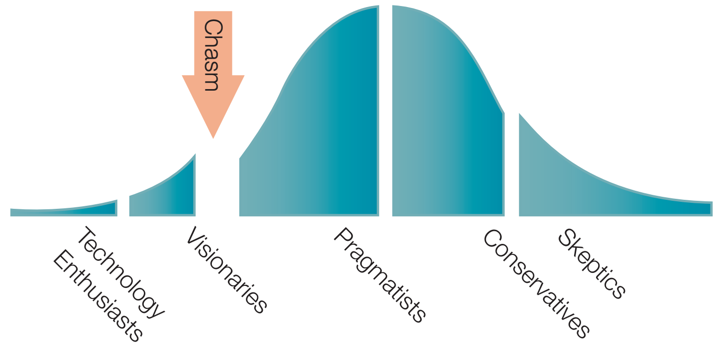
The smart grid future promises new and improved technologies, along with an integrated system that enables many kinds of data and information to flow to and from different end points and applications – from energy generation to the T&D system to the meter and into the customer's home or business. In concept, this "system of systems" will be more efficient and cost effective, replacing or integrating multiple stand-alone systems. It will also be more streamlined, enabling data to flow through one system to wherever it is needed. Customer value will be enhanced through improved system reliability, customer energy management data and tools, and customer choice. Operational efficiency will also be enhanced through enabling advanced monitoring, control and automation of the T&D system, resulting in cost savings, improved customer service and safe operations.

How utilities migrate to this future will be different for each utility. For PSE, building to a smart grid vision or implementing smart grid technologies is an *evolution,* not a *revolution*. It involves building upon and leveraging our existing investments, as well as our experience, in a careful and thoughtful approach, ensuring customer value and security of the network. It is through this strategy that PSE continues on the path toward a smarter future.

PSE, like other utilities, has a number of information technology (IT) systems – some enterprise-wide, some integrated, and some stand-alone. Most were implemented over time, based on specific business needs and drivers. To gain the efficiencies and future applications envisioned by smart grid, an integrated IT system is needed, and one that is sufficiently smart, secure and agile to carry out the communications. Developing a plan for the development of this system, as well as a strategy for integrating appropriate existing systems and components, is a "tall order" that affects virtually every utility's T&D and IT assets.

Because the smart grid touches almost every part of the utility – technologies, infrastructure, customers, workforce, and operational processes, implementation will necessarily be phased over time. Some investments will be made to replace systems that are outdated or at the end of their useful life and the replacement systems will come equipped with smart grid functionalities as a "standard," much the way the personal computer you buy today has significantly greater functionality than the computer you bought five years ago. Other investments will be made in a more targeted manner to develop specific smart grid functions where there are benefits to do so. Because implementation will necessarily be an evolution, it is critical that consideration be given throughout to potential future upgrades or replacements, compatibility across systems, employee training, and customer education.

Much of the work PSE is doing is dependent on industry agreement on standards and interoperability. PSE actively participates in standards committees, but like most other organizations, waiting until standards are settled is the appropriate decision for PSE and our customers.



What PSE has learned over the past decade is that *phased deployment and careful and ongoing selection of appropriate technologies facilitate success.* This means implementing technologies that are mature, reliable, cost effective (when the technology surpasses adoption by visionaries or early adopters) and able to deliver stable, proven processes for PSE and our customers.

Wisely selecting and funding smart grid-enabling technologies, and then piloting them with PSE customers and employees to ensure both acceptance and usability, provide for a well-architected and systematic advance into smart grid deployment that both minimizes risk and is sensitive to the impact on customers and energy rate structures.

Over the next 10 years, PSE will continue to:

- Upgrade and replace aging infrastructure as needed – IT systems, back-end information systems, and T&D systems – with consideration to smart grid;
- Work with customers on the development of easy-to-use energy management capabilities and reporting tools/information;
- Evaluate and selectively deploy two-way automated metering technology;
- Evaluate and selectively deploy self-healing and automated rerouting of power through automation to improve reliability throughout the T&D system;
- Evaluate and deploy selective demand response programs and other customer energy capabilities; and
- Develop the plan for an integrated IT system and selectively implement phases of the plan.

Above all, PSE will continue to monitor and investigate the success and lessons-learned from the many utilities and vendors involved with smart grid stimulus-funded projects around the country. With nearly $10 billion infused into the industry over the next three to five years, PSE believes there is much to be gained from others' experiences – minimizing risk to our customers – as new technologies, security and consumer acceptance are tested.

There's no question that a smarter grid can bring many benefits to both utilities and customers, something that PSE has already demonstrated. A smarter grid enhances system reliability and efficiency, and empowers customers with the ability to manage their energy efficiently, two of PSE's core objectives. The bottom line: Getting the smart grid *right* will benefit our economy, our environment and our customers for years to come, while getting it wrong will mean lost opportunities and lost dollars at a time when we can't afford either.

Puget Sound Energy
Smart Grid Technology Report

Introduction

Smart grid refers to an improved electricity supply chain that runs from a power generating facility all the way to the end-use or application of electrical energy inside a residence or a place of business.

A fully developed smart grid features monitoring, analysis, control and communications capabilities along the entire electricity delivery chain. The ultimate goal of smart grid is 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(3)(a), offers a discussion about smart grid and outlines Puget Sound Energy's approach to date as well as our plan for achieving a smarter system that benefits our customers and our utility operations.

The major sections of this report are:

- Background – working definition and vision of smart grid, benefits to customers and utilities, and regional considerations;
- PSE's Current Approach – PSE's strategy for and approach to implementing smart grid components;
- PSE's Implementation Plan – PSE's two-year implementation plan and a 10-year roadmap for further developing a smart system;
- Glossary – acronyms and terms defined;
- Appendices – additional details that capture report requirements and further define information in the report.

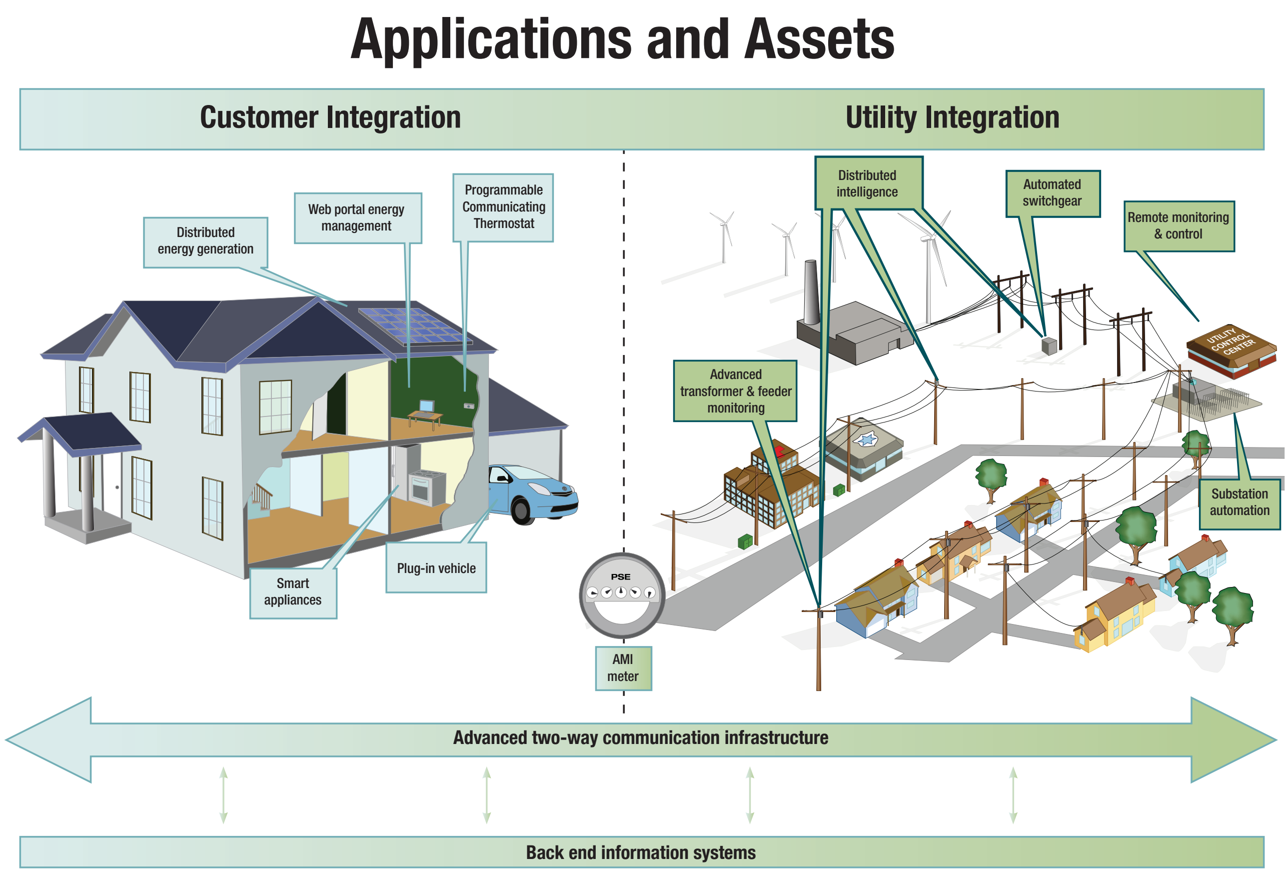
Background

The electric grid has been called the most complex machine in the world. The term smart grid relates to many different technologies and systems that are part of the grid, and thus seems to be defined in just as many ways.

Envision a smart grid supported by a safe, secure IT system; that is more reliable and efficient through monitoring, control and automation; that provides customers with better information, control and automation to manage their energy use; that engages customers with their utility in managing the overall grid through demand response or critical peak pricing programs; and that supports the adoption of new consumer-driven technologies such as renewable energy generation and electric vehicles. This brings us to the future of smart grid: a system that delivers value to its stakeholders through optimization of system capabilities and energy utilization.

The following illustration (Figure 1) displays a sampling of the many potential aspects of smart grid, including customer and utility applications and assets, two-way communication infrastructure and back-end information systems, all of which are expected to benefit both customers and utility operations.

Figure 1: Illustration of Potential Smart Grid Applications and Assets



While an end-to-end smart grid with monitoring, communications and control built into all levels as illustrated in this graphic does not yet exist in its entirety, the major components are known. A smart grid can be broken down into four major parts:

- The back-end information systems, which are comprised of major information and control systems, including the Customer Information System (CIS), Meter Data Management System (MDMS), Outage Management System (OMS), Energy Management System (EMS), Distribution Management System (DMS), and Geographic Information System (GIS);
- The communication infrastructure, which is the conduit that carries information between the back-end information systems and devices located either at the customer's premise (e.g., meters, energy management systems, home automation networks) or at locations in the utility's T&D system infrastructure (e.g., substations, switches, capacitors);
- Applications directed to customers which include devices that provide energy information, manage energy use (e.g., demand response, electric vehicles), or enable distributed energy generation;
- Applications that manage the utility's assets, which include devices located at substations, switches, capacitors and other distribution system locations that enable monitoring and control of system conditions.

A fully implemented smart grid promises to deliver greater reliability because of reduced outages; the potential to reduce the cost of electricity by efficiently being able to balance energy supply and demand; new possibilities for products and services that businesses and consumers do not have access to today; improvements in environmental quality as customers gain access to more renewable energy choices; and an enhanced ability for customers to self-manage their energy consumption. While there are many established and emerging technologies in each of these areas, there is still much debate around the world about how to achieve a smart grid in a way that is fiscally efficient and customer centric. This is a challenge that faces all utilities working to implement smart grid.

For long-established utilities like PSE, smart grid implementation requires a thoughtful strategy and approach. With the need to integrate existing IT back-end applications and networks along with T&D components (some of which are currently working independently from each other), new technologies must be evaluated for their integration capabilities. On top of these challenges, is the careful consideration that must be given to the changes likely to affect our customers, workforce and utility operations. Managing this change effectively across the utility and educating customers along the way will be key success factors.

While the challenges may seem daunting, the benefits are promising.

It's expected that customers will be able to manage their energy usage and costs with better information, control and automation. Interactive and incentive programs such as demand response, critical peak or time-of-use pricing will create opportunities where customers can work with their utility in managing the overall grid, reducing green house gasses, and deferring capital expenses. Reliability will be improved and system additions will be optimized as utility operators will be able to manage, control and automate the grid more effectively with better information at multiple places throughout the grid. And with the market dynamics of change and opportunity, new products, services and technologies are likely on the horizon for the consumer as well as the utility.

Smart grid technology advancements and investments must be made at multiple levels of infrastructure: from the end devices and IT systems that facilitate communications between customers, the utility and the energy grid; to the underlying physical infrastructure that operates within substations and extends to the far reaches of the T&D system that must ultimately be integrated with the IT system. This will require careful planning and consideration of remaining useful life and the integration of existing assets, as well as ensuring forward compatibility of individual systems as grid assets and the associated monitoring, communications and control systems evolve. The resulting costs of these necessary infrastructure and IT investments can be quite large and may, in some cases, only obtain partial benefits until all pieces are integrated.

How utilities continue on the path to a smarter future will be different for each utility. With a significant number of variable factors, such as regional differences, environment, customer interest, and utility size and infrastructure, to name a few, each utility will need to define the path that is most strategic for their set of circumstances.

As smart grid advancements become a reality – particularly for PSE and our customers, a combination of environmental and technology factors should be considered:

- ***Tempered cost benefits:*** The Pacific Northwest has long enjoyed one of the lowest electrical power rates in the nation, due to the development of federal hydropower projects. Although rates are beginning to experience modest increases, power costs to utility customers are still far lower in the Pacific Northwest than in other regions. This tempers some of the immediate cost benefits of certain smart grid programs like time-of-use pricing, but doesn't change the broader trend toward greater monitoring, communications and control in the energy system.

PSE's Lower Baker Dam in Skagit County

- ***Demand-side resource options:*** PSE's circumstances find it faced with acquiring additional resources to meet capacity needs, largely due to expiring contracts and retiring energy generation assets. PSE's 2009 Integrated Resource Plan (IRP) outlines a need for the utility to add 676 megawatts (MW) of generation capacity and demand-side resources by 2012. Options to deliver some of these demand-side resources include demand response and home automation programs. To enable these programs at scale will require substantial investments in smart grid-related communications and back-end information systems to enable two-way communications. These additional infrastructure components must be considered in the context of these trends to ensure the successful timing of their acquisition and deployment to cost-effectively support the expansion of demand-side resources.

PSE's first wind facility, Hopkins Ridge Wind Facility in Columbia County

- ***Renewable energy integration:*** Renewable energy is of significant interest to PSE and our Pacific Northwest customers. PSE is already producing electricity from the wind and sun, and from land filled waste products, which will be an increasingly important part of our energy future. Smart grid advancements need to consider the integration of renewable energy, distributed generation, energy storage, thermally activated technologies, 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 opportunities:*** Like many utilities, PSE is faced with requirements for increased spending on aging infrastructure which will need to be modernized or replaced. This presents an opportunity, as modernization and/or replacement of these systems will allow the planning for both current and future needs. At the same time, with more frequent information (i.e., nearly real-time) at additional points throughout the system, enabled by a smart grid, we can improve optimization of our current electric infrastructure by deferring investment closer to the time when it is needed. Therefore, we need to carefully and strategically implement smart grid solutions.
- ***Technology risk awareness:*** The technology required to upgrade IT systems and enable further smart grid applications is at uneven levels of maturity for deployment. While some technologies and applications are proven and at a point where research and development (R&D) cycles have ended and commercialization has begun, others are still unproven, risky, expensive and require further development. Further, the technology embedded in 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.
- ***Determine real value:*** Even with technologies that continue to make smart grid smarter, we need to be sensitive to our customers and their needs. This means considering the deployment of pilot programs to determine cost effectiveness and benefits to customers, as well as customer acceptance. A smart grid can't be smart unless it provides stakeholders with both real and perceived value.

- ***Customer = Driver:*** On the other hand, it is critical that utilities like PSE stay in tune with customers who are already actively engaged in energy matters – from participation in energy efficiency programs and pilots to being early adopters of electric vehicles and distributed energy generation – as the market and consumers will be an important driver of smart grid advancements for utilities.
- ***Reliable service still rules:*** Residential and business customers depend daily on PSE for reliable service, and PSE is obligated to provide that service at a reasonable cost. It naturally follows that the pursuit of smart grid technologies should further enhance this mission.

PSE's Current Approach

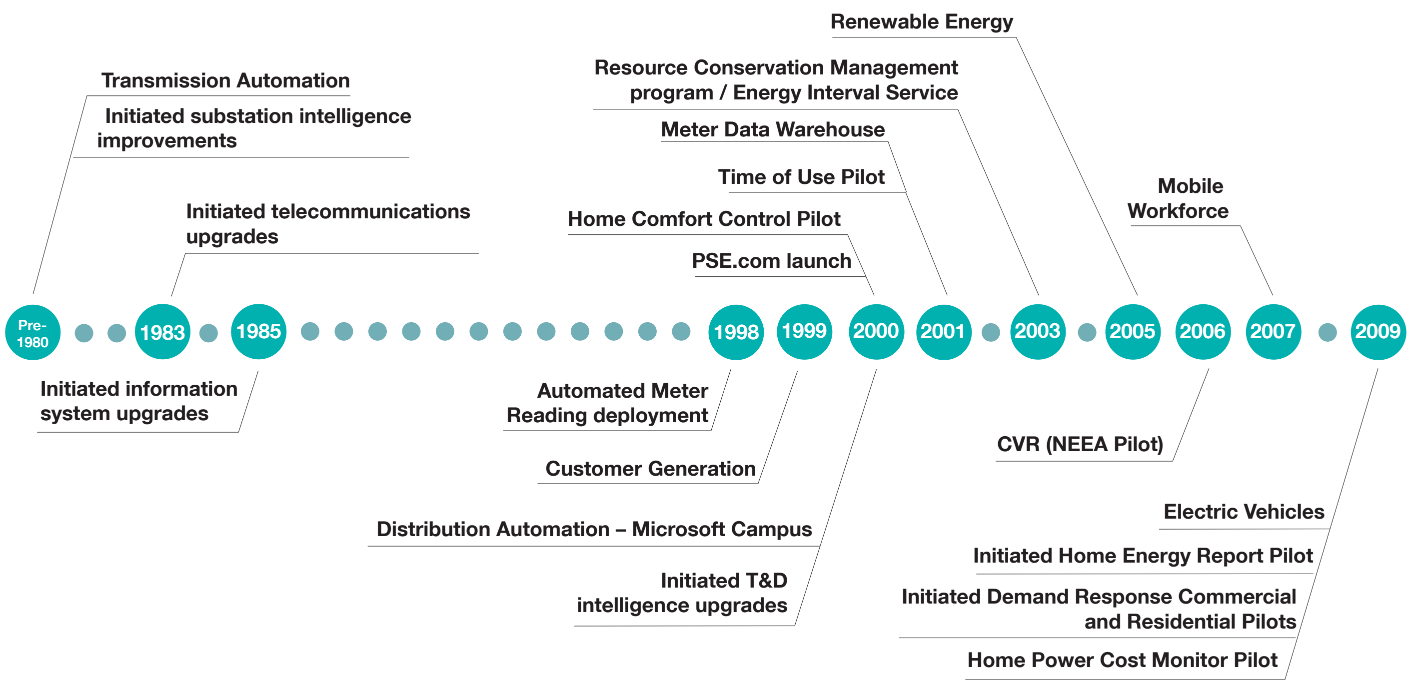
PSE does not have a "fixed" vision of an ultimate smart grid deployment; but we do have an understanding of what smart grid could be and what it may ultimately deliver to our customers. The future of smart grid could very well look like the illustration shown on page 4.

At present, a multi-billion dollar national investment in smart grid projects is leaving the planning stage and beginning to be tested. Many utilities are trying to figure out where to begin with the smart grid, or how to catch up with others, like PSE, that have decades of experience with smart grid components. The utilities new to smart grid aim to transform themselves across the next several years, through a combination of proven and new technologies.

However, both the operating models for these new technologies, and the business models for the utilities that adopt them, remain challenging to pursue. The best way to combine performance, security, privacy, and economy in the smart grid is still a work in progress. The utility industry will learn a great deal about the smart grid in the next few years, but this learning will come at a cost, and will entail risks.

PSE has already learned many lessons about the smart grid through a series of projects spanning decades (see Figure 2):

Figure 2: PSE's History of Deploying Smart Components



The key lesson that PSE has learned from its experience investing in new technologies is that careful selection and phased deployment are essential. The smart grid won't be built all at once. *(See Appendix A for more information about PSE's history of deploying smart grid components.)*

With our experience (e.g., PSE's early commitments to automated meter reading, self-healing transmission lines, and utility-scale wind generation), PSE isn't in the same position as many other utilities. On the road to the smart grid, PSE doesn't need to figure out where to begin, or how to catch up. Instead, across these next few years, PSE will continue to progress at a measured pace, moving toward developing an enterprise architecture, implementing prudent projects, and improving its operations, service, security, and customer relationships.

As the industry moves forward into the smart grid, PSE will continue to learn about new technical innovations through industry research and its own pilot programs. Individual innovations may take PSE in new directions (e.g., as has been the case with Home Energy Reports): we will remain flexible, agile, and open to change. But only once a new technology is proven to help provide reliable, safe, and secure energy services at a reasonable cost will PSE consider widespread implementation.

PSE's smart grid initiatives fall into three broad categories: information technology, customer information and energy empowerment, and transmission and distribution infrastructure. In these areas we find that our employees and customers can work together through the smart grid to achieve the highest levels of efficient, reliable and secure service.

In IT, PSE will move toward an enterprise service-oriented architecture (SOA) as we select new applications with this architecture already imbedded. PSE has already implemented a number of smart grid components and programs, but these are not fully integrated into one network or system. PSE is now evaluating an enterprise service bus (ESB) system to integrate these independent systems. There is a consensus in the energy utility industry (as indicated by the National Institute of Standards and Technology (NIST) security and interoperability standards) that ESBs will underlie the next generation of utility smart grids.

Within this enterprise architecture, PSE is planning to upgrade a variety of enterprise applications, including its CIS, OMS, and DMS. PSE also plans to design, procure, test, and deploy an enterprise GIS.

In the area of customer information and energy empowerment, PSE will be working over the next several years to initiate or continue pilots that will allow us to effectively test the capabilities of new technologies and anticipate customer needs.

In transmission and distribution infrastructure, PSE's most fundamental smart grid initiative will be the continuation of upgrades to aging infrastructure and the completion of planned initiatives targeted to increase reliability for customers and reduce outage duration.

These are a sampling of PSE's current smart grid initiatives; others are indicated below. Whether over the next two years or the next 10 years, what all of these initiatives have in common is PSE's measured, disciplined pace of implementation.

PSE's Implementation Plan

PSE has developed a smart grid technology implementation plan that takes into account the regional landscape and our integration approach. Our plan details our efforts for the next two years, and maps to where we see ourselves heading over the next 10 years. As spelled out by the WAC requirement, our plan focuses on the implementation of smart grid technologies, but it also describes how we will support our customers as they pave their own path into the world of smart grid. ***Obviously, these plans will likely be adjusted as we learn from our current activities and pilots and the industry at large, and as our customers learn more about their needs/desires. Our plans are also subject to resource and budget limitations.***

Over the next 10 years, PSE will continue to:

- Upgrade and replace aging infrastructure as needed – on IT networks, back-end information systems, and T&D systems – with consideration to smart grid;
- Work with customers on the development of easy-to-use energy management capabilities and reporting tools/information;
- Support customer energy needs/desires, e.g., electric vehicles, customer generation;
- Evaluate and selectively deploy two-way automated metering technology;
- Evaluate and selectively deploy self-healing and automated rerouting of power through automation to improve reliability though the T&D system;
- Evaluate and selectively deploy demand response programs and other customer energy capabilities; and
- Develop the plan for the integrated IT network and selectively implement phases of the plan.

PSE also expects that as 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 implement activities in the following areas:

- Home intelligence/automation;
- Electric vehicle services;
- Automation, self-healing, enhanced demand response and the ability to integrate traditional and non-traditional energy sources (e.g., wind, solar) in the grid; and
- Customers supplementing the grid with generation and/or storage during peak.

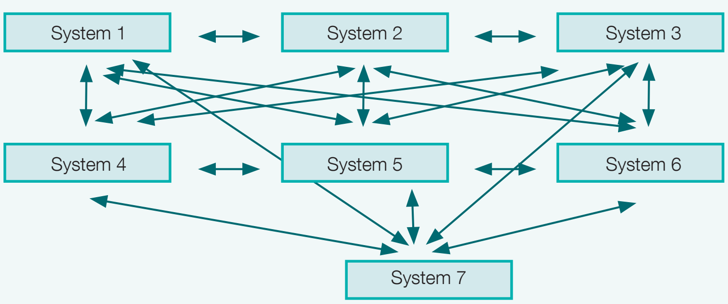
Following is an overview of PSE's plans in the areas of information technology, customer information and energy empowerment, and transmission and distribution infrastructure. The two-year implementation plan and 10-year roadmap broken out by smart grid component or project follows each overview, with more detail provided in Appendix B.

Information Technology

To continue to meet utility and customer demands, and to anticipate the future of smart grid, PSE is heading toward a more efficient enterprise SOA. The SOA will be based on strategies and policies for data integration, network design, and security. It is likely to be based on an ESB system, consistent with federal security standards (i.e. NIST).

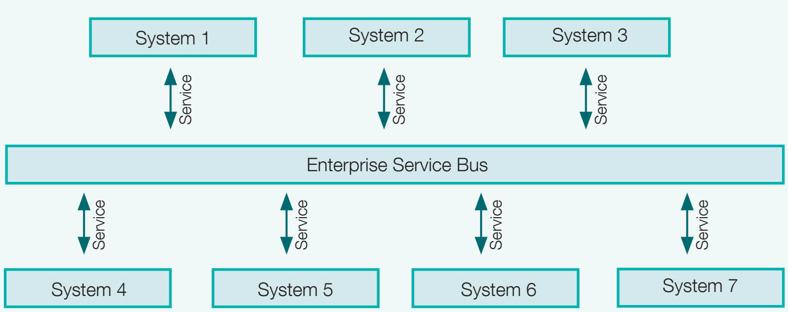
The illustrations below indicate how the new architecture and other projects will take PSE from a traditional point-to-point structure to a service-oriented structure.

Figure 3: Illustration of PSE's Current Point-to-Point Structure



PSE's current architecture, point-to-point, consists of direct connections between each pair of systems needing to be integrated. When the number of systems involved is small, point-to-point can be a low cost, efficient solution. However, as smart grid functionality drives new integration requirements the number of interface components is expected to grow exponentially. Attempting to meet the new requirements via point-to-point integrations, and the resulting exponential growth in cost and complexity, would prove unsustainable.

Figure 4: Illustration of a Service-Oriented Architecture



In an SOA approach, each system uses a software service to publish data of interest to other systems to the ESB. Systems then use additional services to monitor the ESB and retrieve data of interest. As systems are added or replaced, only the services connecting the system to the ESB are impacted, resulting in lower development and maintenance costs.

Within this enterprise architecture, PSE is planning to upgrade our EMS, CIS, OMS and DMS systems, and procure our first enterprise-wide GIS system. In addition, PSE will complete development and integration of our MDMS, and prepare for the transition from our one-way AMR system to a two-way AMI.

To enable this new architecture and transport of the multiple types of data and information, PSE's network infrastructure is transitioning to Internet Protocol (IP). PSE's network infrastructure now provides telecommunications connectivity to roughly 800 locations through leased telephone services and a dozen providers in addition to PSE's private network. The private network includes 300 miles of fiber optics lines and 40 microwave paths, and employs two types of systems, one IP and the other TDM (time-division multiplex). Over time, the plan is to transition from TDM to IP.

PSE has aligned these major categories of information technology initiatives 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 cycles, and which systems deliver the greatest immediate value to our customers, critical business initiatives as well as smart grid. Equally germane to this assessment process is budgeting/funding, for as all-encompassing as updating and replacing an aging system infrastructure is, it must still be achieved while being sensitive to the rate of investment, rate structure, and impact to customers.

Information Technology/Systems

2011-2012 Plan

- Complete EMS upgrade to increase system security and reliability
- Implement OMS: complete evaluation by 2011; select vendor, implement with completion expected in 2012

10-year Roadmap

- Complete OMS-DMS-EMS-MDMS integration
- Upgrade CIS
- Implement enterprise wide GIS
- Complete integration of MDMS to Outage and Engineering applications

Automated Metering

2011-2012 Plan

- Complete evaluation of migrating to two-way AMI technology from one-way AMR meters in 2011
- Pilot and initiate a phased conversion from AMR to AMI, based on evaluation and business drivers

10-year Roadmap

- Continue AMR-AMI conversion, as appropriate

Substation IP Enablement

2011-2012 Plan

- Complete evaluation of pilot to migrate T&D substations to secure IP network
- Continue extension of fiber optics cabling throughout T&D network

10-year Roadmap

- Based on pilot results, migrate T&D substations with DNP (Distributed Network Protocol) to a secure IP (Internet Protocol) network. Upgrade substation RTUs (Remote Terminal Units) from Vanguard, an older, proprietary network protocol, to DNP/IP standard protocol between the T&D substations on a secure IP network with point to point communications within the substations
- Continue extension of fiber optics cabling throughout T&D network

Customer Information and Energy Empowerment

During the next 10 years, customer adoption will be a key driver in PSE's deployment of smart grid technologies. For example, electric vehicles and their charging stations, customer energy generation, energy demand response and home automation can affect the grid at its deepest, localized level: the distribution grid and the individual services that connect homes and businesses to the grid, and that allow customers to control energy usage down to the level of a single household appliance. As these new customer installations change and begin to increase peak load on our T&D system, PSE will need to consider several smart grid capabilities to help manage and optimize the system – from access to improved, immediate 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 capabilities and reporting tools/information; better information through two-way automated metering technology; and other customer energy capabilities such as household energy usage and appliance monitoring and adjustment. Anticipating customer needs/desires will also drive our need to find new solutions for security and customer privacy.

Customer Energy Use Information and Feedback

2011-2012 Plan

- Continue to review and evaluate proposals; consider the deployment of pilot programs to learn the potential savings and value proposition to customers
- Continue implementation of home online tools with PSE customer base

10-year Roadmap

- Continue to review and evaluate proposals; consider the deployment of pilot programs to learn the potential savings and value proposition to customers

Home Power Cost Monitor Pilot

2011-2012 Plan

- Complete pilot and evaluate results, such as energy savings, technical feasibility and cost effectiveness
- Based on pilot, determine potential broader deployment

10-year Roadmap

- Expand application as appropriate, based on pilot evaluation and future applicability

Demand Response (DR) Pilots

2011-2012 Plan

- Evaluate current residential and commercial DR pilots, including system performance and customer acceptance for demand response

10-year Roadmap

- Expand application as appropriate, based on pilot evaluation and future applicability

Home Intelligence/Automation

2011-2012 Plan

- Consider soliciting proposals for a pilot project

Prepay Billing System Pilot

2011-2012 Plan

- Consider soliciting proposals for a pilot project

Customer Energy Generation

2011-2012 Plan

- No specific technology changes, evaluations or projects are anticipated in the next two years, however, PSE will continue to support customer adoption of small renewable generation
- In anticipation of this rapidly growing program (9,000 net metered customers are projected by the end of 2015), evaluate and implement streamlined solutions:
  - » Implement new customer interconnection process improvements
  - » Expand renewable generation section of PSE.com website
  - » Implement policy and process for interconnection for customer generation projects between 100 kW and 2 MW

10-year Roadmap

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

Electric Vehicles

2011-2012 Plan

- Update review of energy and capacity demands in latest IRP
- Study impacts of early electric vehicle adopters on distribution levels and develop plan for changes to planning and customer service models to support mass adoption
- Continue collaboration with major customers and public infrastructure in the region to support regional planning of transportation and utility infrastructure, and consumer information on location and use of charging stations
- Evaluate the value to customers and the utility from timed or staggered charging based on actual data from early customers. Pilot if positive economic case and communications standards and equipment are in place

10-year Roadmap

- Develop energy and demand forecasts based on already experienced adoption rates and needs
- Incorporate EV loading and forecasts into distribution and transmission planning, and design standards where appropriate
- If customer benefits can be demonstrated, scale a program in step with IT communications and meter rollouts and customer demand

Transmission and Distribution Infrastructure

PSE will be exploring, evaluating and selectively deploying T&D smart grid strategies over the next 10 years and beyond. Driven by our objective to provide reliable service, such strategies will be evaluated and most will be piloted prior to implementation. These pilots and evaluations will consider the diversity of our service area (i.e., downtown core, suburban, rural), and the high density of trees and vegetation as all can be a challenge to reliability. In addition, maintaining decades-old infrastructure, including the existing smart components on our T&D system, will require a level of replacement that is expected to continue and possibly increase as the smart grid evolves in the future.

Coordination between T&D and IT will help ensure customer value at each step/stage as the upgrade and consolidation of the IT system and end-use applications are planned.

PSE cross-country transmission lines

Transmission Automation and Reliability

2011-2012 Plan

- Evaluate existing automatic transmission schemes for performance and determine the need for new schemes and/or modifications to existing schemes. Select projects based on specific benefits and costs and available funding
- Continue to upgrade aging/older SCADA systems in transmission substations

10-year Roadmap

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

Distribution Automation

2011-2012 Plan

- Continue to monitor and learn from the DA systems serving Microsoft
- Evaluate and develop pilots in one to two select areas where reliability is an issue

10-year Roadmap

- Expand distribution automation in areas with high critical load and/or reliability concerns

Distribution Supervisory Control and Data Acquisition (SCADA)

2011-2012 Plan

- Continue SCADA installation; select projects based on specific benefit and cost, and available funding
- Install supervisory control of feeder breakers and ampere readings on all three phases of breakers at critical distribution substations

10-year Roadmap

- Continue expansion of functionality with the long-term goal of all distribution substations having SCADA with ampere readings for all three phases at the breakers; and supervisory control of the feeder breakers

Recloser Installation

2011-2012 Plan

- Continue to install reclosers on overhead distribution circuits where customers would reliably benefit from the installation
- Evaluate and pilot one recloser with communications for remote monitoring and control

10-year Roadmap

- Continue expansion of recloser installation program and expand communications and monitoring capability depending on evaluation, pilot and benefit/cost

Conservation Voltage Reduction (CVR)

2011-2012 Plan

- Evaluate and develop plan for CVR program, and implement as budget funding allows

10-year Roadmap

- Expand CVR program to appropriate locations where cost-effective implementation yields further energy savings

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 for integration into our system, please refer to Appendix B.

Conclusion

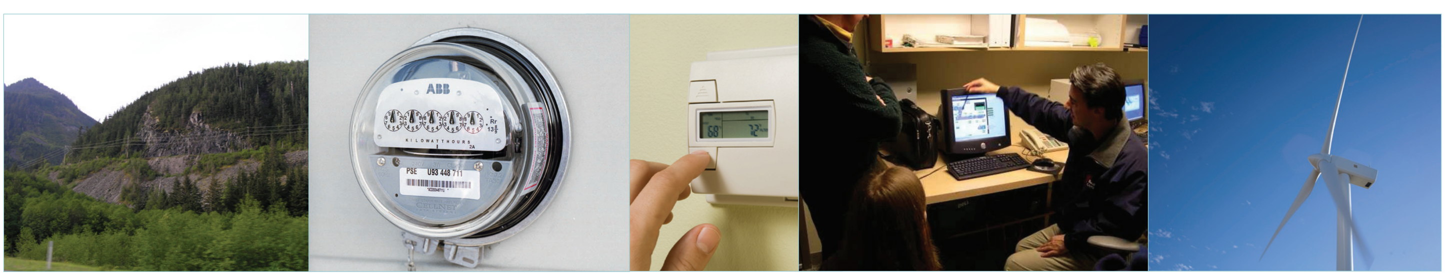
Smart grid strengthens the nation's energy infrastructure, and empowers decision-making for utilities and their customers by providing timely information on energy usage, the operation of the grid, and production.

One key to smart grid deployment will be prudent and systematic introductions of smart grid technology at each level of infrastructure, from T&D and IT systems, to customer premises applications and information systems. System interoperability and standards definition both play critical roles in this deployment, because technologies can only be deployed once they are certified to be interoperable both today and in the foreseeable future.

A second focal area for smart grid technology investment will be the maturity of the technology itself. Because smart grid is continually evolving, a prudent approach will include comprehensive pilot testing of smart grid technologies to ensure that the technologies deliver on their promises; that they are interoperable; that their vendors will continue to be financially viable and able to continue to support and develop the technologies over time; that the technologies are cost-effective; and that PSE customers will accept and adopt the technologies.

A third critical focal area will be cost recovery 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 mission-critical components of every project (smart grid or other) that PSE undertakes.



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.

ARRA-American Recovery and Reinvestment Act.

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.

BPA-Bonneville Power Administration.

CAD-Computer-aided Design.

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.

Cloud Computing-Internet-based computing, whereby shared resources, software, and information are provided to computers and other devices on demand.

CMS-Customer Management System.

COBOL-Common Business-Oriented Language, a third generation software application programming language used frequently on computers designed and developed prior to 1990.

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

Conservation Resources Advisory Group (CRAG)-A group of stakeholders providing guidance for PSE's energy efficiency program planning and delivery including: WUTC staff, Attorney General Office of Public Counsel, NW Energy Coalition, Energy Project, Natural Resources Defense Council, Northwest Power and Conservation Council, Industrial Customers of Northwest Utilities, Northwest Industrial Gas Users, Washington State Department of Commerce, and the DOE Weatherization Assistance Program provider network. Additionally, customer representatives from the residential, commercial, industrial, and institutional sectors serve on the Advisory Committee. Other interested parties may attend Advisory Committee meetings as well, but will not be considered Advisory Committee members.

Conservation Volt 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 homes, thereby reducing energy waste.

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-Where utility customers produce their own energy (e.g. solar panels, wind turbines).

Customer Management System (CMS)-An independent database and user interface that tracks customer contacts regarding energy efficiency outreach and implementation, similar in function to a customer relationship management tool. A CMS is able to extract, mine, prioritize, sort and append customer data with other data elements for the purposes of generating leads and tracking participation for energy efficiency programs.

CRAG-Conservation Resources Advisory Group.

CVR-Conservation Voltage Reduction.

DA-Distribution Automation.

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

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

Distributed Energy Generation-When electricity is generated from many decentralized energy sources.

Distributed Generation-An eligible renewable resource where the generation facility or any integrated cluster of such facilities has a generating capacity of not more than five megawatts.

DMS-Distribution Management System.

DNP-Distributed Network Protocol.

DOE-Department of Energy.

DR-Demand Response.

EES-Energy Efficiency Services.

EISA-Energy Independence and Security Act.

EMS-Energy Management System.

Energy Interval Service-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.

Enterprise Service Bus (ESB)-A software architecture construct which developers typically implement by using technologies found in middleware infrastructure products (usually sitting between the application software and the operating systems). ESB is often designed based on recognized standards.

ESB-Enterprise Service Bus.

Failover-Backup operation that automatically switches to a standby network if the primary system fails or is temporarily shut down for servicing. Failover is an important fault tolerance of mission-critical systems that rely on constant accessibility.

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.

Geographic 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.

GIS-Geographic Information System.

HMI-Human Machine Interface.

Hohm-Home energy monitoring system sold by Microsoft.

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.

IED-Intelligent Electronic Device.

IEEE-Institute of Electrical and Electronics Engineers.

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.

Interoperability-The ability of software and hardware on multiple machines from multiple vendors to communicate.

IP-Internet Protocol.

IRP-Integrated Resource Plan.

IT-Information Technology.

kV-Kilovolt.

LC-Load Control.

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 the legacy system.

Load Balancing-The use of various techniques by electrical power stations to store excess electrical power during low demand periods for release as demand rises.

Load Office-PSE Power System Control Center. Its functions are to sense the pulse of the power system, adjust its condition, coordinate its movement, and provide defense against internal/external events occurring to the power system.

MDMS-Meter Data Management System.

MDW-Meter Data Warehouse.

MEMS-Meter Exception Management System that helps track billing issues.

MW-Megawatt.

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.

NIST-National Institute of Standards and Technology.

OMS-Outage Management System.

PAP-Password Authentication Protocol.

PCT-Programmable Communicating Thermostat.

PEV-Plug-in Electric Vehicle.

Phasor-A number that represents both the magnitude and phase angle of the sine waves found in electricity.

PLC-Programmable Logic Controller.

Plug-in Electric Vehicle Charging-The replenishment of electrical energy supply in an electric vehicle.

PMU-Phasor Management Unit.

Prepay Billing System-A meter- or billing-based solution in which customers pay for electricity before it is consumed. Customers purchase a certain amount of “credit” in advance and must purchase additional credit before they have consumed the amount of electricity necessary to deplete the fund in the account.

Programmable Logic Controller-A digital computer used for automation of electromechanical processes.

Proprietary Technology-Technology licensed under the exclusive legal right of its owner, and often only able to be run on that owner’s equipment.

PV-Photo-voltaic.

R&D-Research and Development.

RCM-Resource Conservation Management.

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

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.

RFI-Request for Information.

RFP-Request for Proposal.

RTU-Remote Terminal Unit.

SCADA-Supervisory Control and Data Acquisition.

Self-Healing-Technology capable of automatically repairing itself so its operations remain uninterrupted.

Service Oriented Architecture (SOA)-A flexible set of software development and design principles that provide reusable software modules that can be used by different computer programs.

Smart Grid-A smart grid delivers electricity from suppliers to consumers using two-way digital technology to control appliances at consumers’ homes to save energy, reduce cost and increase reliability.

SOA-Services Oriented Architecture.

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 realtime 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.

TA-Transmission Automation.

TCP/IP-Transmission Control Protocol/Internet Protocol.

TDM-Time-Division Multi-plexing.

Transmission Automation (TA)-Intelligent technology that enables the transmission system to run itself without human intervention.

V-Volt.

VAR-Voltage Ampere Rates.

Virtualization-A technique used to provide a simulated environment where a variety of different operating systems can be run on a single machine.

Voice over Internet Protocol (VoIP)-The delivery of voice-based communications over the Internet.

VoIP-Voice over Internet Protocol.

Voltage Ampere Rate (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.

VPN-Virtual Private Network.

Appendices

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Appendix A

PSE's History of Deploying Smart Grid Components

PSE's history of deploying smart grid components dates back to before 1983. Following is a description of each of the components identified on the historical timeline featured on page 7 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) in response to isolate faulted sections of the high voltage line. The purpose was to improve reliability by 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 which 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 140 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 remote terminal units (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 bulbs 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 300 miles of fiber optics lines and 40 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 Network Management System – Installed in 1997 to provided 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

Communications is managed today primarily through two types of systems, one IP and the other TDM (time-division multiplex). 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

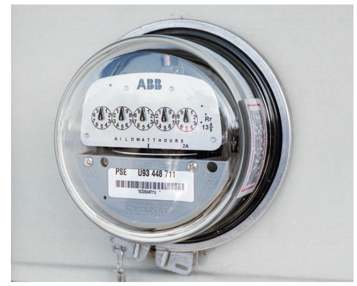
IT Applications: Between 1985-2000, PSE acquired or developed most of the back-end legacy information systems (e.g., CIS, EMS, components of an OMS and DMS) that support PSE's business. From 2000-2009, PSE continued to enhance and customize these systems to reflect PSE's evolving business needs. Recognizing that many of these systems would not continue to be sustainable with new and emerging business needs, PSE initiated RFI/RFP processes and overall system architectural studies in 2008 to determine future direction and system replacement/upgrade strategies that will eventually result in either system modernization or replacement. Meanwhile the data warehouse and reporting system that monitors customer energy usage was completed and installed in late 2009.

IT Networks: From 2000-2008, PSE developed seven discrete and secure networks to serve as the communications backbone for PSE's gas, electric and information assets. During this same timeframe (2006), ruggedized laptops were deployed for field service technician communications. The laptops contain encrypted databases, and use Voice over IP (VoIP) and IP communications. Beginning in 2009, PSE began an architectural review of its networks, with an overall goal of consolidating these networks into one or two company networks under a virtual private network (VPN) structure. Also in 2009, PSE began participation in interoperability standards committees and NERC-defined Critical Infrastructure Protection (CIP).

1998

Automated Meter Reading Deployment

PSE began discussions of moving to an Automated Meter Reading system back in 1995. There were three pilots using different technologies between 1995 and 1998, when a decision was made and deployment began. The system is a one-way radio frequency transmission from the meter. Deployment ran from 1998 – 2002, at which time all but 70,000 meters were changed. The final phase to capture those 70,000 was completed during the summer months of 2006. Total automation today includes just over 1.8 million natural gas and electric meters.

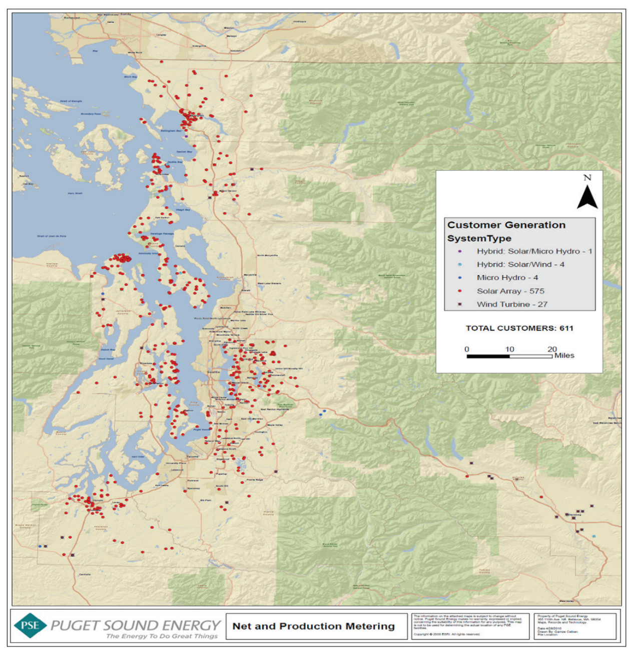


PSE meter

1999

Customer Generation

PSE's support of customer generation programs began in 1999 with the net metering program. Presently, 694 customer generation systems contribute to the grid, with 94 percent of customers generating energy from solar photovoltaic (PV) systems. The program grew slowly until July, 2005. In 2005, Washington State implemented the Renewable Energy Cost Recovery Program which is an incentive-based program where customers with eligible 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 has helped accelerate the adoption of customer generation. The utility bills provided to customers are a net of energy generation against energy consumption of the household. The program continues to grow, and based of past growth patterns, customer generation systems are expected to reach 9,000 by the end 2015. PSE currently uses a legacy billing system, so production of "net bills" that net energy generation against energy consumption per household or business are manually calculated.



Customer generation across the PSE service area

2000

Distribution Automation-Microsoft Campus

In the late 1990s, Microsoft requested and paid the incremental cost for a more robust and reliable distribution system serving its Redmond Campus, and later its Redmond Ridge Facility. The initial project consisted of installing SCADA switches on a select number of critical campus buildings. The SCADA switches have increased from the original six to 42 switches today. Through SCADA, PSE's system operator can remotely monitor and control, 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 rest of the sections.

In the early 2000s, the system was enhanced to a "self healing" system; again focusing on critical buildings on the Redmond Campus and its Redmond Ridge Facility. Over half of the campus SCADA switches are now automated with a pre-programmed logic software; the same software used for PSE's transmission system automation. The software 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

In 2000, PSE began installation of three phase reclosers on distribution feeders to reduce the impact of outages; in 2009, a more aggressive program was initiated to improve overall reliablity. 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.

Recloser on PSE power pole

Home Comfort Control Pilot

PSE collaborated with three vendors to deliver 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 for which software and thermostat control technology was tested for curtailment events triggered by PSE.

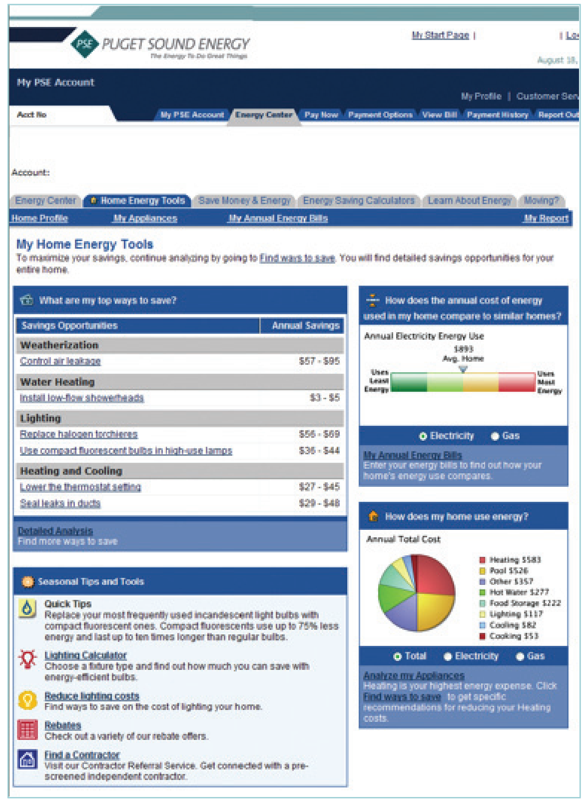
Participants, notified of upcoming curtailment events messages on their thermostat screens, could override any event at the press of a button. Participants could also access their thermostats over the Internet, to read and reset them.

The pilot experiment proved HCC could be feasible and reliable. PSE initiated 41 successful events, setting back the participants' thermostats by 2 degrees F or 4 degrees F for two hours, across a range of morning, mid-day 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% 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's website, PSE.com, launched in 2000. In 2005, My PSE Account was added, which allowed customers to view their statements, leverage home energy tools (pictured) to download energy use analyzers, see their previous days' energy consumption, and pay their energy bills online. Online bill payment was then 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.



PSE.com home energy tools

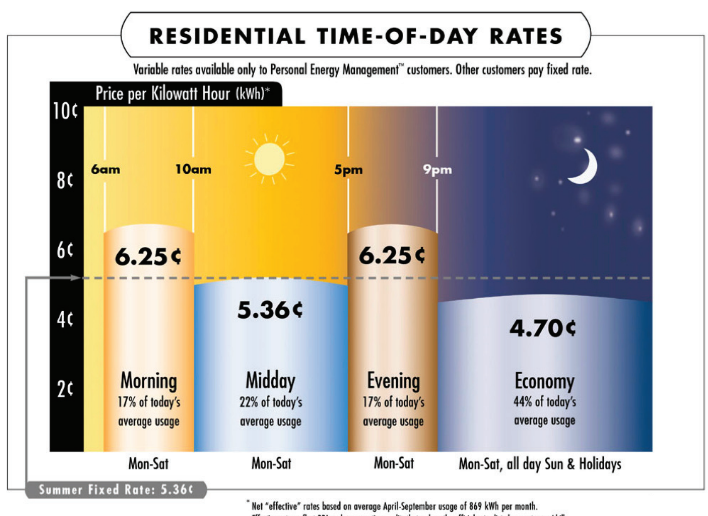
2001

Time of Use Pilot

PSE designed and implemented a time-of-use (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 time-of-use (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 the western states' power crisis, which had been characterized by extreme price volatility. PSE also had the "Conservation Incentive Program" in place.



Customers participating 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 half of one 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 crisis nearly over, and the 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 five percent per month, over a 15-month period;
- It is important to manage customer expectations about bill savings;
- Consumer education is important, and should be done in a variety of ways to ensure clear communication. A variety of means were used, including: advertising, letters, refrigerator magnets, a company web site that provided a listing of load shifting activities and associated savings estimate, and a personal web site 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.; and do your laundry on Sunday.

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. Initially the MDW served as a storage facility for data. Between 2002 and 2008, the system was enhanced to include functions like validation, load profile, service order, diagnostic flags, outage and customer presentment. Tools were built for ease of use as an enterprise application. Most recently, in 2010, the MDW was upgraded to a full MDMS, capable of handling the intricacies of a smart grid environment. This includes accepting multiple meter read files daily, enhanced outage reporting for both end points and network equipment, read recovery capability and Web services for real-time applications.

2003

RCM Program/Energy Interval Service

Prior to the 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 as 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.

Data in a digital format enables the analysis of energy use which in turn identifies opportunities to adjust building system performance for optimization

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, which is of particular interest to PSE RCM customers, PSE supports the 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 and so far the only 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 2010, started developing the Lower Snake River Wind Energy Project in southwest Washington.

Demonstration solar array at PSE's Wild Horse Wind and Solar Facility

2006

Conservation Voltage Reduction (CVR) – NEEA Pilot

PSE originally conducted its first CVR study on 10 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. Commonly referred to as CVR, the results of the study conclusively showed that operating a utility distribution system in the lower half of the acceptable voltage range (120-114 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 10 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.

2007

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 secure virtual private network (VPN).

2009

Electric Vehicles

Recognizing that PSE's customers would be adopting electric and plug-in hybrid vehicles in the coming years, PSE entered two converted plug-in hybrids into fleet use and is working with several municipal customers and research entities who have done the same. Using this data, 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. As more customers adopt these vehicles over the next few years, PSE will be expanding data collection efforts to develop better models based on real-world conditions.

PSE plug-in hybrid

Home Energy Reports

In 2009, PSE-began providing home energy reports for 38,000 PSE natural gas and electric residential customers. The home energy reports are designed to motivate and educate recipients to take action to improve their homes' energy efficiency. The reports utilize daily meter reads to provide each participant with a direct comparison of how his/her home energy consumption compares to that of neighbors who live in similar homes. Consumption patterns are analyzed to disaggregate the usage of various systems around the home in order to more accurately guide a customer toward targeting systems that are consuming the most energy.

Each Home Energy Report contains three key personalized components:

- Comparisons of recent energy use to a group of comparable neighbors, including comparison of the participant's recent energy use to the prior year;
- Normative messages designed to motivate action;
- Targeted energy efficiency advice that includes specific tips based on the home's energy use pattern, housing characteristics, and household demographics.

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 2009. PSE's primary focus is to pilot direct 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. PSE will evaluate the effects of these pilot demand response options on its electrical system. Recaps to date:

Residential Load Control

A major success was the response rate (nearly eight percent) of enrolled customers, which tripled the average response rate for similar programs in other utilities. The first demand response events were called on the morning of December 7, 2009, and on the evening of December 8, 2009, with 300 customers participating in each event. At the end of December 2009, 525 customers were enrolled in the program.

Commercial/Industrial Load Control

Curtailment events were conducted ("called" in Demand Response parlance) December 8, 2009 and December 9, 2009, under severe cold weather conditions. Nominated capacity for both events was 2.92 MW or about 70 percent of maximum due to selected test geography. Curtailment performance (unaudited) for 12/8 – 241 percent and 12/9 – 141 percent of the 2.92 MW nominated capacity. An evaluation contractor has been selected and plans for evaluation of this pilot were developed to begin during first quarter, 2010.

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 a sensor attached to the customer's meter which wirelessly sends 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. PSE will evaluate the pilot in 2010 for energy savings, compared with a control group of customers without power cost monitors.

Appendix B

Details of PSE's Two-year 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, might contribute to its systems. A full catalog of these technologies would span the industry and its vendors. Certain technologies are then evaluated in more depth for roles within particular active projects; smart grid technologies under such active consideration are discussed below. Thus some of the information required by the WAC requirement will become available on a rolling basis as projects are defined.

The following plans will likely be adjusted as we learn from our current activities and pilots and the industry at large, and as our customers learn more about their needs/desires. Our plans are also subject to resource and budget limitations.

Information Technology

To continue to meet utility and customer demands, and to anticipate the future of smart grid, PSE is heading toward a more efficient enterprise service-oriented architecture (SOA). This is likely to be based on an ESB system consistent with federal security standards. PSE's enterprise architecture will be based on strategies and policies for data integration, network design, and security. Network design will be IP-based. PSE has already implemented NIST 800-53 as a control standard, as well as typical automated procedures such as identity management, access management, configuration management, patch management, intrusion detection and vulnerability assessment.

Within this enterprise architecture, PSE is planning on several upgrades or new systems: EMS, CIS OMS and DMS, and an enterprise wide GIS system. The different development directions and objectives of these enterprise application projects reflect both PSE's requirements and the maturity of vendor offerings. Additionally, PSE will complete development and integration of MDMS, and prepare for the transition from our one-way AMR system to a two-way AMI.

PSE is also planning an initiative to transition telecommunications traffic to Internet Protocol (IP). PSE's telecommunications infrastructure currently transports a wide variety of information, including voice, data, SCADA, alarm, security, protection, and radio. It provides connectivity to roughly 800 locations, through leased telephone services, including hundreds of circuits from over a dozen providers, and PSE's private network. The private network includes 300 miles of fiber optics lines and 40 microwave paths, and employs two types of systems, one IP and the other TDM (time-division multiplex).

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 cycles, and which systems deliver the greatest immediate value to our customers, critical business functions, along with smart grid. Equally germane to this assessment process is budgeting/funding, for as all-encompassing as updating and replacing an aging system infrastructure is, it must still be achieved within the constraints of rate structure objectives.

Finally, PSE's information technology approach to the smart grid requires interoperability for systems, networks, edge and end devices. With government and industry standards in flux for both interoperability and security, PSE is taking a step-by-step approach to deploying interoperable information technologies. Yet every project proceeding through PSE's replacement sequence must provide interoperability to the degree feasible at the time.

Area: Information Technology
Project: Upgrade Energy Management System (EMS)
Project Description (including goal/purpose of technology): Upgrade the EMS to meet PSE operational needs, stay current with existing and future NERC & FERC Cyber Security Advisories, and support future needs. This project began in early 2010 and is currently in progress. Planned milestones for upgrade from EMS software version 2.2 to 2.5 • Design, configure to upgraded version by Q4, 2010 • Testing in Q2, 2011; • Cutover by Q4, 2011. The intent is to meet the following high-level strategic objectives: • NERC compliance/security – The upgrade will satisfy the NERC Advisory • Reliability/Security – Upgrading the Enterprise Management Platform (EMP) will increase overall system reliability & security • PSE Energy Platform software consistency – Currently PSE's three environments contain varying versions the energy applications. Upgrading to common and updated versions will contribute to a more consistent and more-supportable architecture. • Updating hardware – Upgrading outdated hardware will increase performance, security and reliability. • Future upgrade infrastructure accommodation – Upgraded hardware and software will be installed to help accommodate and support PSE's future business needs, future EMP architectural roadmap and general energy functionality.
Total Estimated Costs: $2.3 million to 2.7 million.
Benefits/Considerations (cost effectiveness, operational savings, effects on system capability, non-quantifiable societal benefits, economic considerations): This upgrade enables PSE to stay current with existing and future NERC and FERC Cyber Sercurity Advisories. Additional benefits and considerations are described in the detailed project delivery plan "Energy Platform Upgrade" in Appendix D.

Area: Information Technology
Project: Outage Management System (OMS)/Distribution Management System (DMS)
Project Description (including goal/purpose of technology): The existing OMS and DMS systems have limited functionality and are legacy systems that are not integrated. The systems also have shortcomings communicating directly with the electric grid in providing real-time monitoring and reporting. While the OMS/DMS selection process is slightly ahead of selection of other key end-use systems (e.g., CIS, GIS), PSE is reviewing these systems holistically, considering key integration points and functionality to meet overall business requirements. An initial evaluation to understand the current functionality offered by OMS vendors was completed in early 2010. Seven OMS vendors responded to PSE's request for information (RFI); and six OMS vendors provided in-depth demonstrations of their OMS application suites summer 2010. PSE anticipates issuing an RFP to three finalists with selection planned for late 2010. Design, testing, and implementation of OMS is planned for 2011 and early 2012. Completion of the OMS is planned for summer 2012. The final step is completing OMS and DMS integration by 2020. The improved OMS and DMS systems will enable remote monitoring and control, and will provide seamless and comprehensive reporting on the status of the T&D system.
Total Estimated Costs: TBD; review process is underway; RFP is expected to be issued in Q3 and selection by end of 2010.

Benefits/Considerations (cost effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): Technology benefits/considerations include improved service reliability, as OMS will enable a faster response and restore times/for outages, better visibility to the system, and improved information for customers. The detailed benefits/considerations are included in the Request for Information for OMS in Appendix D.

Area: Information Technology
Project: Automated Metering
Project Description (including goal/purpose of technology): Today, PSE's 1.8 million customer base is installed on one-way meters that do not have the bi-directional communications capability needed for smart grid. Vendors in metering information technology have made great strides in the development of electronic meters, specialized communications chips built into different meters, and meter data software across the last decade since PSE acquired its AMR system. PSE will complete evaluation of two-way AMI technology in 2011, and determine whether and how to transition to two-way AMI from our current AMR technology. In considering this two-way technology and network, cyber security will be considered. With two-way AMI technology, capabilities supported by other means, such as demand-response programs, Web-based customer information, and other interactive applications, can be supported.
Total Estimated Costs: TBD, based on evaluation.
Benefits/Considerations (cost effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): As the evaluation has not yet been completed, the benefits and considerations are under review.

Area: Information Technology
Project: Substation IP (Internet Protocol) Enablement
Project Description (including goal/purpose of technology): Evaluate and pilot the migration of selected T&D substations to IP communications capability in 2010-2012 timeframe. Assuming the evaluation and pilot confirm our assumptions, continue migration for T&D substations. Continue the extension of fiber optics cabling throughout PSE's T&D network within guidelines of the 10-year budget. Presently, all PSE substations are not IP-enabled to allow seamless communications between the electric grid, customers and back-end information systems that are needed for smart grid. Secondly, as greater reliance is placed on secure IP-based communications, these communications will require larger bandwidth for rapid transport. This can be enabled by fiber optics cabling throughout the T&D network. This is a significant infrastructure effort and expenditure that PSE is approaching in a phased manner so as to facilitate its execution within budget parameters. The end result, a full IP enablement of all PSE substations, will deliver not only more automation and operational control over facilities without the need to actually be onsite, but also point to point communications between all substations to facilitate automated events such as failover (and the continuance) of energy delivery, with a reduction in power outages and/or time to restore power. Data latency issues will also be avoided/improved.
Total Estimated Costs: TBD, based on evaluation.
Benefits/Considerations (cost effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): Details of the benefit/considerations are included in the project delivery plans "IP SCADA Network Proof of Concept" and "IP Core" in Appendix D.

Customer Information And Energy Empowerment

In the next 10 years, PSE will continue to work with customers in the development of easy-to-use energy management capabilities and reporting tools/information; and the deployment of other energy-oriented customer capabilities such as:

- Home Automation;
- Customer Energy Use Information and Feedback;
- Customer Security and Privacy;
- Customer Energy Generation;
- Electric Vehicles.

The long-range vision for home automation is that there will virtually be no corner of home living space or home appliances that smart grid won't be able to manage. Characteristics of this "smart home automation" are:

- Digital meters, smart thermostats and other devices that allow customers to adjust their energy consumption based upon their preferences and rates;
- Solar panels that collect energy which can be sent back to the grid and netted against home energy usage expenses;
- Home computer access to a web portal that allows customers to view real-time information on energy usage, with the ability to change energy settings;
- 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;
- Electric plug-in 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 the levels of automation and energy management they are comfortable with, and the degree of involvement that they feel is appropriate for their utility to assist them in home energy management. It is PSE's responsibility to provide customers with the information and educational resources that equip customers to make informed decisions—and to run pilot projects that evaluate consumer comfort levels with new technology as well as the cost- and quality-effectiveness of the technology itself.

PSE will also continue to support its customers with new and existing customer energy generation. It is projected that PSE will have 9,000 energy generation customers by the end of 2015.

Finally, our customers must be assured that access to and storage of information are secure and private. Customers are concerned that through smart grid and smart meters, hackers will be able to break into home computers. PSE will need to communicate about security with its customers, and to launch an educational and informational program that addresses home security concerns. A second area of potential customer security concern is that PSE will hold more of their household information, and potentially share it with others. PSE needs to demonstrate to customers that it already has a comprehensive privacy policy that protects customers' interests, and that it is both sensitive and responsive to privacy issues.

Area: Customer Information and Energy Empowerment
Project: Customer Energy Use Information and Feedback–Home Energy Report Pilot
Project Description (including goal/purpose of technology): The Home Energy Report pilot is a low-cost/no-cost behavioral modification energy savings project that provides home energy reports to 38,000 gas and electric single family customers. PSE selected this pilot from among four vendor responses to its 2007 Targeted Energy Efficiency Request for Proposal solicitation for low-cost/no-cost behavior modification energy efficiency opportunities. The pilot was launched in the third quarter of 2008. The pilot will continue to run through 2010 to test the durability and longevity of energy savings. PSE customers use data from PSE's MDW to compare customer energy usage to energy usage from nearest like neighbors. Home Energy Reports are customized reports mailed directly to PSE customers that help each residential customer better understand their home electric and gas consumption, motivate them to conserve, and provide targeted calls to action tailored to help each customer save money and improve energy efficiency. There will also be a web interface, although customers will continue to receive mailed paper reports unless they opt out of the mailings. A description of some of the report components and their characteristics is listed below. Home energy reports are modified to meet the needs of PSE. • *12-month Energy Comparison Report:* Combines GIS (geographic information system) data with historical energy data to show customers how their energy use compares to other residents who are most like them (i.e., age of house, square footage of house, on their block or in their zip code). This has been proven to be the single most effective piece of information to motivate consumers; • *Targeted Energy Savings Tips:* For every season and city, there are simple changes that customers can make to reduce their energy consumption. The tips are targeted based upon a number of factors, including housing data, demographic information (e.g., renter vs. home-owner), and energy consumption patterns; • *Progress Tracker:* The Progress Tracker reinforces the positive aspect of energy savings by applauding customers who reduce their consumption, and by assisting customers who are not progressing. This component employs well researched messaging to reinforce norms. Early results for the cost effectiveness of the Home Energy Report behavior modification energy savings program are favorable. If these energy savings are persistent and more is learned regarding their requirements for maintenance, the program will be further developed and deployed where appropriate in PSE's service area. The program is poised to be expanded to approximately 150,000 gas and electric customers at the request of communities within PSE's service area that are recipients of ARRA (American Recovery and Reinvestment Act) funds for increased energy efficiency.
Total Estimated Costs: As outlined in the Energy Efficiency Services Conservation Rider Saving Goals and Budgets, 2010-2011, $2,261,000 (includes electric and natural gas customers).
Benefits/Considerations (cost effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): The goal of this pilot is to gain knowledge of customer acceptance, energy savings potential, technical feasibility and cost effectiveness of this technology. If cost effective energy savings are deemed achievable through the pilot evaluation, further program planning will ensue to garner more energy savings.

Area: Customer Information and Energy Empowerment
Project: Customer Energy Use Information and Feedback–Website/Online tools
Project Description (including goal/purpose of technology): PSE makes strategic use of web-based technologies to communicate information with its customers that empowers the decision-making of residential and commercial customers regarding their energy use. PSE's AMR network enables the Web capability that allows customers to view their previous day's energy consumption. PSE delivers information services as part of its energy efficiency program. Information services provide customers with quality information that will assist them in making cost-effective decisions relative to energy efficiency investments, and motivate them to participate in eligible energy efficiency programs and services while simplifying the process to take action. Today, PSE relays information to its customer base via e-format on the company's website (PSE.com) in addition to brochures and inserts in paper-based billings. The information covers several areas: • Billing and energy use • Information on how to conserve and manage energy, along with cash incentives and online energy savings calculator tools • Information and education on renewable energy, along with the promotion of PSE's "green" program, which allows customers to purchase all or a portion of their energy from green energy sources • Opportunities for customers to sign up for on-premise PSE inspections and recommendations on how household and business energy use can be optimized • Details on low income assistance and/or tax incentives The PSE website also shows residential and business customers the goals and results of PSE's overall effort to achieve energy performance efficiency. Reports of energy usage (along with calculators and online tools for energy management) are provided to customers via the PSE website, with customers being able to access their household or business data in a secure environment. PSE plans to deploy an updated PSE.com in 2011. The upgrade will integrate online energy efficiency resources with PSE's Customer Management System (CMS) in order to better support delivery and results tracking of energy efficiency programs, services, customer program participation. It will also provide tracking and evaluation of the efficiency and effectiveness of promotions and program implementations. The updated website will improve the presentation of information to customers such as an interactive house with direct links to rebates, and searchable retailer lists. It will also feature better navigation, and provide greater interaction such as the ability for customers and service providers to fill out rebate forms electronically.
Total Estimated Costs: As outlined in the Energy Efficiency Services Conservation Rider Saving Goals and Budgets, 2010-2011, $985,000.
Benefits/Considerations (cost effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): Through the redesigned website, PSE expects to better grow program participation, generate awareness, reach out to customers and community, enable and empower self-service energy management, energize trade-ally and community distribution networks, and create stakeholder engagement and community.

Area: Customer Information and Energy Empowerment
Project: Home Power Cost Monitor Pilot
Project Description (including goal/purpose of technology): PSE selected this pilot from among four vendor responses to its 2007 Targeted Energy Efficiency Request for Proposal solicitation for low-cost/no-cost behavior modification energy efficiency opportunities. In 2009, PSE provided 1,012 Blueline Home Energy Displays to customers living in single family structures thought our service territory. The program was provided on a first-come, first-serve basis to customers who were willing to pay $29.95 for the devices. The displays attach to customer electric meters and provide real-time feedback to customers regarding their electric usage. It is the intent of this program to assist customers in conserving energy by providing instant feedback about their energy usage. Although Blueline Home Energy Monitoring Displays have been around for several years, the system is still relatively new to the utility arena, with only a few studies that successfully identify valid and defendable energy savings associated with the monitor. Because this program is new to PSE, relies heavily on people making actionable choices, and has an undetermined measure life, PSE is pursuing independent evaluation of this program to better understand the persistence and magnitude of energy savings. PSE is currently seeking a qualified statistician to provide an impact evaluation of electric billing data to estimate savings for the first year of this programs operation. The impact evaluation will include both a billing analysis and the use of customer surveys. PSE is also seeking a high level process evaluation that will outline how PSE should structure programs, such as the Blueline Home Energy Display Program, which will make program evaluation easier in the future and allow for PSE to measure program persistence. Through this pilot, we expect to gain knowledge regarding customer acceptance of Home Power Cost Monitor, savings potentials, technical feasibility, and cost effectiveness for potential broader deployment.
Total Estimated Costs: As outlined in the Energy Efficiency Services Conservation Rider Saving Goals and Budgets, 2010-2011, $160,000.
Benefits/Considerations (cost effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): The goal of this pilot is to gain knowledge of customer acceptance, energy savings potential, technical feasibility and cost effectiveness of this technology. If cost effective energy savings are deemed achievable through the pilot evaluation, further program planning will ensue to garner more energy savings.

Area: Customer Information and Energy Empowerment
Project: Commercial and Residential Direct Load Control Demand Response Pilots
Project Description (including goal/purpose of technology): PSE's 2009 IRP presents achievable estimated demand response capacity potential for residential, commercial and industrial customer sectors. Pilots are being undertaken to strengthen the company's capability to responsively and effectively offer cost-effective demand response options to all customer classes in the future. PSE's primary focus has been to pilot direct load control during times of high peak system loads, focusing on the customer communication and equipment needed, as well as the information and incentives needed to get the customer to agree to respond. PSE will evaluate the effects of these pilot demand response options on its electric system as well as customer receptivity and responsiveness. Attributes to be evaluated include technologies, demand reduction performance, customer behavior and preferences, impact and integration of demand response with PSE operations, demand reductions achieved, energy savings achieved, local distribution system benefits derived, and cost-effectiveness of demand reductions.

Small-scale demand response pilots are being offered on a voluntary basis to targeted customers. Residential, commercial or industrial customers receiving retail bundled service have been recruited for participation in demand events. PSE has determined prospective participant eligibility. There is no rate impact to participants and financial incentives may be offered to customers who participate.

Residential Load Control

PSE's residential Demand Response Pilot (DRP) is a two-year limited program targeting direct load control of electric space and water heat. Following UTC approval of PSE's demand response pilot tariff, PSE issued a nationwide request for proposals to 17 demand response vendors with the aid of a third party consultant to help solicit and evaluate bids. Nine vendors submitted bids and were evaluated; four vendors were selected for finalist interviews; and interviews were conducted to select the vendor. At the time of this writing 525 residential customers are enrolled in the program. The program was launched prior to the 2009/2010 winter heating season and is currently planned to end following the 2011 summer season. Total cost of the residential pilot is estimated to be $2.25 million. The residential customers involved in the pilots have electric space heat and water heat, are served from targeted substation circuits, and have existing high speed home Internet service.

Customers' computer and data security are protected via security provisions. See Appendix E for details.

A major success was the response rate (nearly 8%) of enrolled customers, which tripled the average response rate for similar programs in other areas. First demand response events were called on the morning of December 7 and evening of December 8, with 300 customers participating in each event. At the end of December 2009, 525 customers were enrolled in the program.

Commercial/Industrial Load Control

PSE's commercial Load Control Pilot (LCP) is a two-year limited demand response program for large commercial electric service customers located throughout PSE service area. It became fully subscribed with 25 participating customers in the spring of 2009, and is currently anticipated to end following the 2010/11 winter season. Total cost of the commercial/industrial pilot is estimated to be $1.8 million. Data is captured directly from the meter pulse and routed to a vendor supplied server at the customer site. From there it is relayed to the vendor via the customer's broadband compliant with high industry security standards accepted by a wide range of large commercial and federal government facilities that participate in these programs. Curtailment events were conducted ("called" in Demand Response parlance) December 8-9 under severe cold weather conditions. Nominated capacity for both events was 2.92 MW or about 70% of maximum due to selected test geography. Curtailment performance (unaudited) for 12/8 - 241% and 12/9 - 141% of the 2.92 MW nominated capacity. An evaluation contractor has been selected and plans for evaluation of this pilot were developed to begin during Q1 2010.

Through these pilots, we expect to gain knowledge regarding customer acceptance, peak load management, energy savings potential, potential benefit to distribution system management, technical feasibility and cost effectiveness for potential broader deployment.

Total Estimated Costs: As outlined in the Energy Efficiency Services Conservation Rider Saving Goals and Budgets, 2010-2011, $884,000 for the commercial/industrial pilot and $1,078,000 for the residential pilot.

Benefits/Considerations (cost effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): The goal of this pilot is to gain knowledge of customer acceptance, peak load management, energy savings potential, potential benefit to distribution system management, technical feasibility and cost effectiveness of this technology. If cost effective energy savings are deemed achievable through the pilot evaluation, further program planning will ensue to garner more energy savings.

Area: Customer Information and Energy Empowerment
Project: Home Intelligence/Automation Pilot
Project Description (including goal/purpose of technology): Consider soliciting proposals for a pilot to identify energy savings potential by deploying communicating home intelligence/home automation devices. This pilot will provide PSE with information on the energy savings value of having integrated home energy use information, display, and controls. Many products available are capable of communication with the utility through mesh networks via metering or internet protocols. Intentions for this pilot will be to identify a product or products that allow homeowners to manage specific outlets, circuits, or appliances from a single dashboard device. The present pilot concept is for 1,500 single family residential homes throughout PSE's combined gas and electric service territory. Additional program targets may be set upon development of the program design. Incentives to the customer will be identified with the development of the pilot program. As a pilot program we will work towards an incentive that will ensure our ability to collect necessary program and evaluation data. Through the pilot, we expect to gain knowledge regarding customer acceptance of home intelligence/automation devices, savings potentials, technical feasibility, and cost effectiveness for potential broader deployment.
Total Estimated Costs: TBD, currently evaluating.
Benefits/Considerations (cost effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): The goal of this pilot is to gain knowledge of customer acceptance, energy savings potential, technical feasibility and cost effectiveness of this technology. If cost effective energy savings are deemed achievable through the pilot evaluation, further program planning will ensue to garner more energy savings.

Area: Customer Information and Energy Empowerment
Project: Prepay Billing System Pilot
Project Description (including goal/purpose of technology): Consider soliciting proposals for a pilot to identify savings potential and occupant behavior based on the installation of a prepay billing module and accompanying in-home display. PSE will explore a non-meter-based prepay monitoring and billing system to help customers monitor and control electric consumption. The in-home display shows customers how much energy they have used, are currently using, and how much credit they have remaining. The program is expected to result in energy savings due to the occupants' heightened awareness. System(s) include advance alerts and warnings when the credit threshold is low and allows for traditional payment methods including Web, phone, mail, and pay stations. The present pilot concept is for 1,000 single family electric customers within PSE's service area. Participation will be voluntary. Additional program targets may be set upon development of the program design. Incentives to the customer will be identified with the development of the pilot program. As a pilot program we will work towards an incentive that will ensure our ability to collect necessary program and evaluation data. Through the pilot, we expect to gain knowledge regarding customer acceptance of prepay billing systems, savings potentials, technical feasibility, and cost effectiveness for potential broader deployment.
Total Estimated Costs: TBD, currently evaluating.
Benefits/Considerations (cost effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): The goal of this pilot is to gain knowledge of customer acceptance, energy savings potential, technical feasibility and cost effectiveness of this technology. If cost effective energy savings are deemed achievable through the pilot evaluation, further program planning will ensue to garner more energy savings.

Area: Customer Information and Energy Empowerment
Project: Electric Vehicles
Project Description (including goal/purpose of technology): Pilot testing of electric vehicles to define and begin implementation of the required physical and support infrastructures. In the next two years, PSE will be studying the impacts of electric vehicles on the energy distribution system and developing a plan that addresses both distribution planning and customer service needed to support customer adoption of electric vehicles. PSE will also continue its collaboration with major customers and public infrastructure in the region to support regional planning of transportation and utility infrastructure, and customer information on location and use of charging stations. Over the next 10 years, PSE will develop energy and demand forecasts based on experience gathered from the pilot, such as customer adoption rates and needs for electric vehicles. These electric vehicle forecasts will be incorporated into T&D planning and design. Customer service processes and integration with other systems will continue to be developed, and if consumer benefits are demonstrated, the program will be scaled and expanded with IT communications, meter rollouts and customer demand.
Total Estimated Costs: TBD, currently evaluating.
Benefits/Considerations (cost effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): Promotion of non-fossil fuels in vehicles, with positive impact on Puget Sound air quality.

Transmission And Distribution Infrastructure

PSE's T&D systems form the backbone of reliable energy delivery to customers, and must be made "smarter" to deliver the types of communications and services that customers expect and that embody smart grid. Critical environmental factors considered in our two year and future plans include:

- The need to upgrade and replace aging T&D infrastructure and components, as well as IT hardware and end use systems, for greater system reliability and efficiency, and to enable future smart grid applications;
- The need to update or install smarter components as new sources of renewable energy are integrated into the system, as customers adopt more renewable technologies, or as technologies change and others become outdated;
- The need to manage the changes proactively with employees and with our customers, as new and enhanced delivery systems are introduced;
- The requirement to plan, manage and deploy new technologies and solutions in a manner that is cost-effective, cost-efficient, and sensitive to the impact on energy rates that consumers and businesses are subject to;
- The need to address the increasing (and changing) regulations under NERC, which enforces regulations for the reliability of the bulk power system in North America, in the context of smart grid.

Area: Transmission and Distribution Infrastructure
Project: Transmission Automation and Reliability Program
Project Description (including goal/purpose of technology): Incremental improvement of the smart transmission system through replacement of aging infrastructure and technologies, and addition of new smart grid functionality of monitoring, remote operations and control, and automation, based on benefits and costs, and available funding: Automatic transmission schemes enhance system reliability and protection under different operating scenarios. As the system topology, load, and generation pattern change smarter and improved automatic schemes are needed. • Automated switches with supervisory control has laid the groundwork for improved system reliability on the transmission system over the past thirty years. These legacy control schemes may need updating or replacing due to load growth, transmission system changes, or degrading components. • Systematic upgrades to replace older SCADA systems in transmission substations; and systematic addition of supervisory control, for remote monitoring and control, will continue for transmission line switches. These projects will occur through timed upgrades that correspond with normal equipment maintenance cycles so as to optimally manage costs and assets.
Total Estimated Costs: Typically $1 million to $1.5 million is allocated annually. Individual projects are then identified and funded based on overall cost/benefit analysis and available funding.
Benefits/Considerations (cost effectiveness, operational savings, effects on system capability, non-quantifiable societal benefits, economic considerations): Projects funded by this program are identified each year with specific benefits and costs. The cost effectiveness for the 2010 program is 2.2 with an overall benefit of improved system reliability and service quality for customers. An example of a specific project with costs and benefits is provided in Appendix D.

Area: Transmission and Distribution Infrastructure
Project: Distribution Automation
Project Description (including goal/purpose of technology): Evaluate and develop pilots to test distribution automation in one or two selected areas where reliability is an issue, as budget funding allows. Compared to the transmission system, there has been limited distribution automation (DA) on the distribution system throughout the industry. However, the new smart grid policy requirements as outlined in Energy Independence and Security Act (EISA) of December 2007 increase the need for distribution automation, and therefore a better understanding of the benefits and challenges of DA for all of its stakeholders. DA includes any automation which is used in the planning, engineering, construction, operation, and maintenance of the distribution power system, including interactions with the transmission system, interconnected distributed energy resources (DER), and automated interfaces with end-users. Many of the DA functions must rely on “primary functions” such as SCADA monitoring and control to provide some benefits, yet they can only be cost-effective if they are part of a larger set of functions. The evaluation is expected to be completed in 2011; and a pilot developed in 2012. The pilot plans to use automated failover and “self-healing” grid concepts integral to smart grid. The goal of the pilot is to instantaneously and automatically report outage information back to PSE as it occurs. PSE anticipates that it will take several years to determine the success of this self-healing distribution automated project. The ultimate goal is to expand distribution automation in areas with high critical load and/or reliability concerns. Additionally, PSE’s plan is to continue to learn from its existing DA systems serving Microsoft, as well as from the pilots and programs that other utilities are implementing.
Total Estimated Costs: TBD, currently evaluating.
Benefits/Considerations (cost effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): As the evaluation has not yet been completed, the benefits and considerations are under review.

Area: Transmission and Distribution Infrastructure
Project: Distribution SCADA System Program
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 almost instantly and transmitted to PSE's Control Area operations center. 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 BPA. • 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. PSE has been installing the SCADA system in the distribution substations over the years to better monitor the substation equipment and distribution system. Currently, nearly 95 percent of PSE substations have SCADA. For all new distribution substations, PSE is installing SCADA to operate and control substation equipment as well as monitoring the equipment. By 2012, distribution substations are planned to have SCADA systems, with supervisory control of the feeder breakers at selected substations. PSE is also upgrading existing SCADA system at the substation to better monitor the equipment and distribution system as well as control the substation equipment. By 2012, PSE is planning to complete 24 additional SCADA improvement projects that will install SCADA on substations without SCADA, and enhance SCADA on selected substations.
Total Estimated Costs: Typically $1.5 million to $2 million is allocated annually. Individual projects are then identified and funded based on overall cost/benefit analysis and available funding.
Benefits/Considerations (cost effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): Projects funded by this program are identified each year with specific benefits and costs. The cost effectiveness for the 2010 program is 9, with an overall benefit of improved system reliability through a reduction in outage duration and improvement in SAIDI. An example of a specific project (Upgrade Feeder SCADA at Marine View Substation) with costs and benefits is provided in Appendix C.

Area: Transmission and Distribution Infrastructure
Project: Distribution Recloser Program
Project Description (including goal/purpose of technology): Most utilities pursuing significant reliability improvement on the distribution system are installing new three phase reclosers on the distribution system. These devices dramatically reduce the impact of outages to customers on the feeder by not requiring the station circuit breaker to lock out interrupting service to all the customers on the feeder. Instead with the installation of reclosers only ½ or less customers will be impacted. PSE has continued to install three phase reclosers over the years to reduce the impact of outages on the feeders to the customers. At present we have about 446 reclosers installed on our 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 the OH circuits where customers would benefit from the installation. In addition, PSE will be evaluating and piloting the installation of a line recloser with communication used for remote monitoring and control of the device. This will help determine the challenges and benefits in using the recloser as a device as part of distribution automation. It is anticipated that greater outage duration will be saved for the customers when the System Operators can remotely operate and control the reclosers.
Total Estimated Costs: Typically $1.5 million to $2 million is allocated annually. Individual projects are then identified and funded based on overall cost/benefit analysis and available funding.
Benefits/Considerations (cost effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): Projects funded by this program are identified each year with specific benefits and costs. The cost effectiveness for the 2010 program is 105, with an overall benefit of improved system reliability through a reduction in outage duration and improvement in SAIDI. An example of a specific project (Install Recloser on Lea Hill 17 Distribution Feeder) with costs and benefits is provided in Appendix C.

Area: Transmission and Distribution Infrastructure
Project: Conservation Voltage Reduction (CVR)
Project Description (including goal/purpose of technology): Evaluate and develop plan for CVR program, and implement as budget funding allows. Overall energy usage reduction for the grid, due to the ability to step down voltage at the substation to the voltage level that a customer residential premise will accept before the energy is delivered to the residence.
Total Estimated Costs: TBD, currently evaluating.
Benefits/Considerations (cost effectiveness, operational savings, effects on system capability, nonquantifiable societal benefits, economic considerations): As the evaluation has not yet been completed, the benefits and considerations are under review.

Appendix C

PSE Project Overviews

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1. *Distribution SCADA System Program*

Project Overview: Upgrade Feeder SCADA at Marine View Substation

Goal/Purpose: PSE has not met the SAIDI SQI for the past four years. The lack of real-time data is preventing system operators from operating the system more efficiently and timely, which leads to longer outages on the distribution system. Distribution SCADA is an effective means to help alleviate such limitations.

Project Detail: This project will reduce the duration of outages by expanding the existing substation SCADA equipment to include the 12.5 kV bus/breakers, and installing new substation SCADA. It will provide real-time data to the system operators for remote monitoring and more efficient operation of the system. It will also benefit the planning engineers in developing system improvement projects. It is estimated that efficiency gained by the system operators and the ability to selectively operate equipment remotely will result in a one hour reduction in outage time.

Alternatives: One alternative is to send more servicemen to investigate outages when they occur.

Cost Estimate: $104,000

SAIDI Benefits: It is anticipated the project will improve the outage duration by one hour. The overall customer minutes saved is estimated to be 109,710 (7,314 customers at Marine View/4 circuits X 60 minutes) every three years.

2. Distribution Recloser Program

Project Overview: Install Recloser on Lea Hill 17 Distribution Feeder

Goal/Purpose: PSE has not met the SAIDI SQI for the past four years. In 2008, we commissioned Quanta Technology to assist us in developing a roadmap to improve reliability. In this report, titled Reliability Improvement Roadmap, June 24, 2008, reclosers are recommended as one of the more cost effective methods to reduce outage duration. Reclosers reduce the impact of outages by automatically sectionalizing the line to isolate the fault, then automatically restoring power to the remaining section of line.

Project Detail: The installation of a recloser on the Lea Hill 17 distribution feeder is planned for 2010. This feeder serves 1,968 customers.

Alternatives: Manual switches can be installed to sectionalize the fault instead of recloser. The travel time and cost associated to operate the manual switches (about 120 minutes) will be saved if a recloser was installed.

Cost Estimate: $50,000

SAIDI Benefits: With the recloser on Lea Hill 17, it is anticipated that half of the 1,968 customer will not be impacted by an outage beyond the recloser. Based on historical performance, about 118,000 customer minutes are projected to be saved every three years.

Appendix D, Appendix E

PSE Business Cases and Project Overviews

Residential Load Control Security Provisions

Appendix D and Appendix E are CONFIDENTIAL and are redacted in their entirety