EXHIBIT NO. ___(SML-20)
DOCKET NO. UE-072300/UG-072301
2007 PSE GENERAL RATE CASE
WITNESS: SUSAN MCLAIN

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-072300** **Docket No. UG-072301**

FOURTH EXHIBIT (NONCONFIDENTIAL) TO THE
PREFILED REBUTTAL TESTIMONY OF
SUSAN MCLAIN
ON BEHALF OF PUGET SOUND ENERGY, INC.

JULY 3, 2008

Delivery System Planning

PSE manages two types of delivery systems. One is company-owned and delivers electricity and natural gas *within* our local service territory to more than 1.6 million customers. The other is "merchant-based" and involves arrangements made with outside companies and organizations to transport power and natural gas *to* our service territory. The two are governed by different rules and planned under separate processes and toolkits. This chapter deals with planning for the PSE-owned delivery system within our service territory. Merchant-based delivery systems are discussed in Chapter 5, Electric Resources. This chapter is organized in five parts.

Our delivery planning process is designed to balance safety, cost, and operational requirements while incorporating consideration of environmental management, regulatory requirements, and changing customer demands; its purpose is to identify the most cost-effective solutions to the needs that we face. Safety, capacity, and reliability are our most important performance criteria. Simply put: How will we safely and continuously deliver enough energy through the pipes or wires to meet the demand on the other end? We must operate the system as safely and efficiently as possible on a year-by-year, day-by-day and even hour-by-hour basis. We must accomplish needed maintenance and improvements as cost effectively as possible. And we must anticipate future needs so that infrastructure will be in place to meet that need when it arrives. Our goal is to fulfill these responsibilities at the lowest reasonable cost.

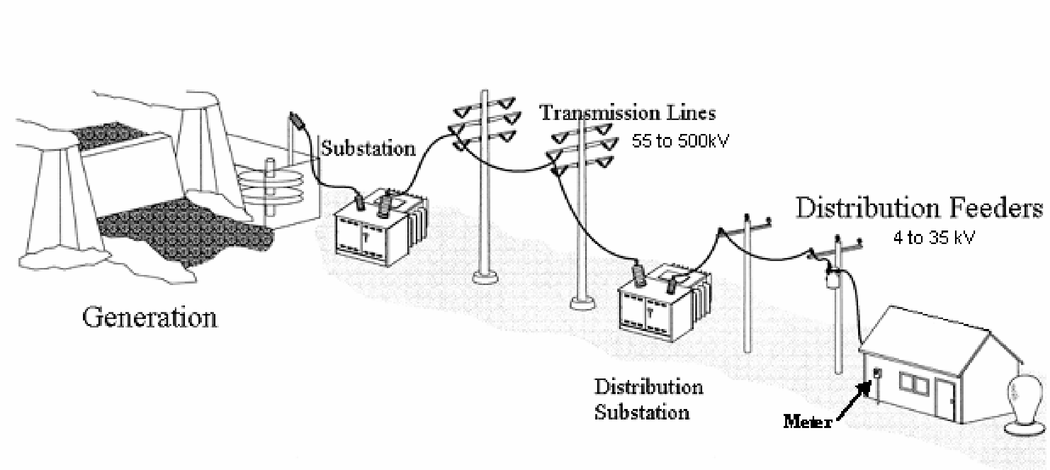
I. System Mechanics and 5-year Infrastructure Plan

To understand the delivery system planning process, it is helpful to understand the mechanics of how gas and electric delivery systems work.

A. Electric Delivery Systems

Electricity is transported from power generators to consumers over wires and cables, using a wide range of voltages and capacities. The voltage at the generation site must be stepped up to high levels for efficient transmission over long distances (generally 55 to 500 kilovolts). Substations receive this power and reduce the voltage to levels appropriate for travel over local distribution lines (between 4 and 34.5 kV). Finally, transformers at the customer's site reduce the voltage to levels suitable for the operation of lights and appliances (under 600 volts). Wires and cables in the system carry electricity from one place to another. Substations and transformers change its voltage to the appropriate level. Circuit breakers prevent overloads and meters measure how much power is used.

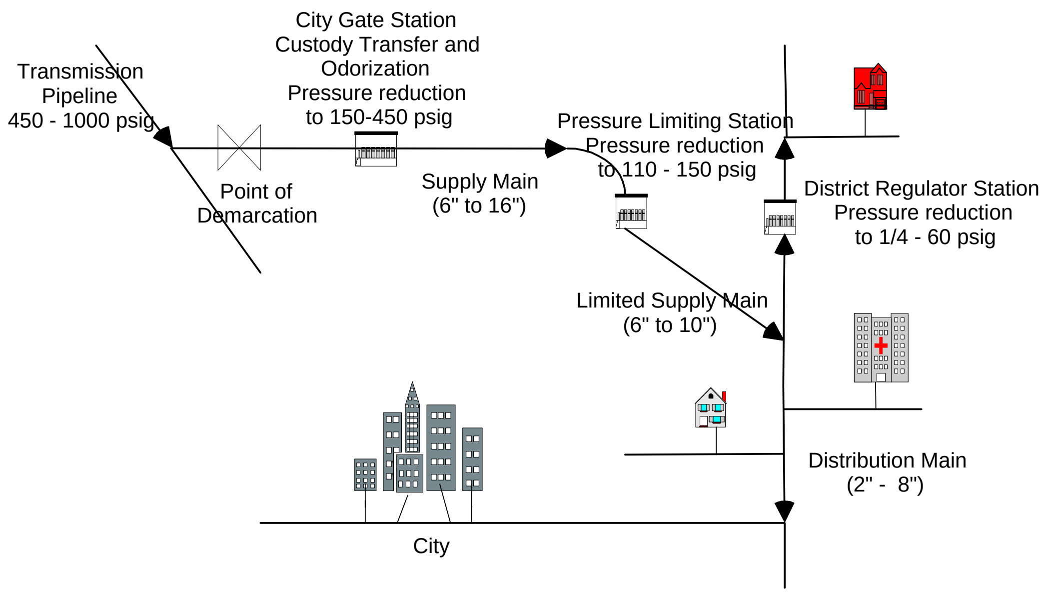
Figure 7-1
Electric Delivery System



B. Natural Gas Delivery Systems

Natural gas is transported at a variety of pressures through pipes of a variety of sizes. Large transmission pipelines deliver gas to city gate stations at high pressures, generally 450 to 1,000 pounds per square inch gauge (psig). There pressure is reduced to 150-450 psig for travel through supply main pipelines to district regulator stations which further reduce the pressure to less than 60 psig. From this point the gas flows through a network of piping (mains and services) to a meter set assembly at the customer's site. At the customer's site, the pressure is reduced to what is appropriate for the operation of their equipment (0.25 psig for a stove or furnace) and the gas is metered to determine how much is used. As gas flows through the distribution system, the system pressure will drop due to friction. This friction and resulting pressure drop depends on the diameter, material, roughness and length of the pipe that is used; it is also impacted by the type and number of fittings that are included in the system. As a result, each of these items is carefully considered when designing the system.

Figure 7-2
Gas Delivery System



C. PSE's Existing Delivery System

The table below summarizes the transmission and distribution infrastructure owned and operated by PSE as of December 31, 2006.

Figure 7-3
PSE-owned Transmission and Distribution System

Electric	Gas
Customers: 1,039,372	Customers: 712,974
Service territory: 4,500 square miles	Service territory: 2,800 square miles
Substations: 358	City gate stations: 39
Miles of transmission line: 2,630	Pressure regulating stations: 755
Miles of overhead distribution line: 10,417	Miles of pipeline: 11,554
Miles of underground distribution line: 9,356	Transmission pipeline pressure: 450-1,000 psig
Transmission line voltage: 55-500 kV	Supply Main pressure: 150–450 psig
Distribution line voltage: 4-34.5 kV	Distribution pipeline pressure: 45-60 psig
Customer site voltage: less than 600 V	Customer meter pressure: 0.25 psig

D. 5-year Infrastructure Plan

The maps and lists that follow show PSE's proposed 5-year infrastructure plan for meeting predicted capacity and reliability needs. The plan is reviewed annually; it remains dynamic. As the plan year gets closer, we refine plan projections based on new developments or information, and perform additional analyses to reveal and evaluate additional alternatives. The plan may change as a result of these investigations.

Figure 7-4
Map of Electric Substation Construction Plans, 2007–2011

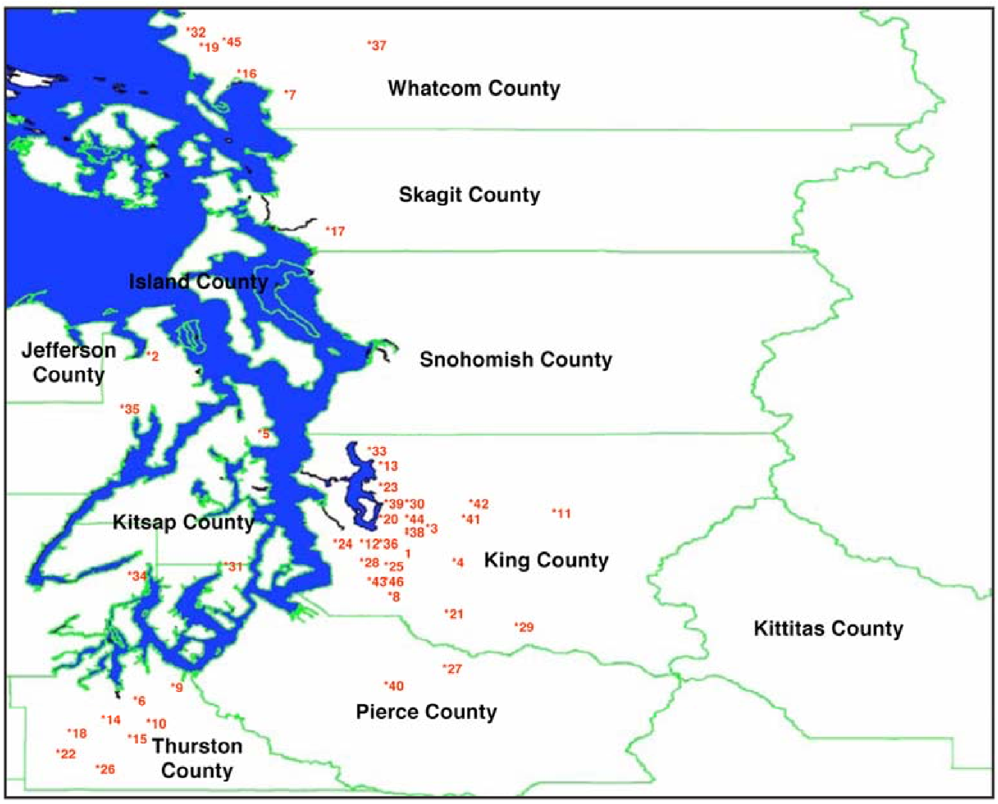


Figure 7-5
List of Electric Substation Construction Plans, 2007-2011

No	Year	Substation	County	Description
1	2007	Serwold	Kitsap	Construct new 115 kV substation with 25 MVA transformer
2	2007	Boeing Aerospace	King	Purchase and rebuild existing 115kV substation. Install new 115 kV, 25 MVA transformer.
3	2007	Chimacum	Jefferson	Construct new 115 kV substation with 25 MVA transformer
4	2007	Christopher	King	Install second 115 kV, 25 MVA transformer
5	2007	Glencarin	King	Construct new 115 kV substation with 25MVA transformer
6	2007	Kingston	Kitsap	Construct new 115 kV substation with 25 MVA transformer
7	2007	Prine Bank #2	Thurston	Install second 115 kV, 25 MVA transformer
8	2007	Sehome	Whatcom	Replace existing transformer with 115 kV, 25 MVA transformer
9	2007	Weyerhaeuser	King	Install second 115 kV, 25 MVA transformer
10	2007	Friendly Grove	Thurston	Replace existing transformer with 115 kV, 25 MVA transformer
11	2007	Plum Street	Thurston	Rebuild existing 55 kV substation to 115 kV. Replace existing transformer with 115 kV, 20 MVA transformer.
12	2007	Mt. Si	King	Construct new 115 kV substation with 25 MVA transformer.
13	2007	Paccar Bank #2	King	Install second 115 kV, 25 MVA transformer
14	2008	Juanita Sub #2	King	Install second 115 kV, 25 MVA transformer
15	2008	Browne	Thurston	Construct new 115 kV substation with 25 MVA transformer
16	2008	Capital	Thurston	Rebuild existing 55 kV substation to 115 kV. Replace existing transformer with 115kV, 25 MVA transformer.
17	2008	Laurel	Whatcom	Construct new 115 kV substation with 25 MVA transformer
18	2008	Eaglemont	Skagit	Construct new 115 kV substation with 25 MVA transformer
19	2008	Thurston	Thurston	Rebuild existing 55 kV substation to 115 kV. Replace existing transformers with two 115 kV, 25 MVA transformers.
20	2008	State St	Whatcom	Replace existing transformer with 115 kV, 25 MVA transformer
21	2008	Factoria Bank 2	King	Rebuild existing 115 kV substation. Install second 115 kV, 25 MVA transformer.
22	2008	Four Corners	King	Construct new 115 kV substation with 25 MVA transformer
23	2008	Longmire Bank # 2	Thurston	Rebuild existing 115 kV substation. Install second 115 kV, 25 MVA transformer
24	2008	Bridle Trails Bank #2	King	Install second 115 kV, 25 MVA transformer
25	2009	Freeway	King	Replace existing transformer with 115kV, 25 MVA transformer
26	2009	Kent Bank #3	King	Install third 115 kV, 25 MVA transformer.
27	2009	Spurgeon	Thurston	Construct new 115 kV substation with 25 MVA transformer
28	2009	Buckley	Pierce	Replace existing transformer with 115 kV, 25 MVA transformer
29	2009	Segale	King	Construct new 115 kV substation with 25 MVA transformer
30	2009	Greenwater	King	Replace existing transformer with 115 kV, 25 MVA transformer
31	2009	Ardmore	King	Construct new 115 kV substation with 25 MVA transformer
32	2009	Bethel	Kitsap	Construct new 115 kV substation with 25 MVA transformer
33	2009	Semiahmoo	Whatcom	Construct new 115 kV substation with 25 MVA transformer
34	2009	Vitulli Bank # 3	King	Rebuild existing 115 kV substation. Install third 115kV, 25 MVA transformer.
35	2010	Fletcher	Kitsap	Construct new 115 kV substation with 25 MVA transformer

No	Year	Substation	County	Description
36	2010	Lakeland	Jefferson	Construct new 115 kV substation with 25 MVA transformer
37	2010	Renton Junction Bank #3	King	Install third 115 kV, 25 MVA transformer
38	2010	Wiser Lake	Whatcom	Construct new 115 kV substation with 25 MVA transformer
39	2010	President Park Bank #2	King	Rebuild existing 115 kV substation. Install second 115 kV, 25 MVA transformer.
40	2011	Center Bank #2	King	Install second 115 kV, 25 MVA transformer.
41	2011	Cumberland	Pierce	Replace existing transformer with 115 kV, 25 MVA transformer
42	2011	Goodes Corner Bank #2	King	Install second 115 kV, 25 MVA transformer
43	2011	Grand Ridge	King	Construct new 115 kV substation with 25 MVA transformer
44	2011	Lake Holm	King	Construct new 115 kV substation with 25 MVA transformer
45	2011	Northrup Bank #2	King	Rebuild existing 115 kV substation. Install second 115 kV, 25 MVA transformer.
46	2011	Whatcom	Whatcom	Construct new 115 kV substation with 25 MVA transformer
47	2011	Krain Corner	Pierce	Install 115 kV, 25 MVA transformer at existing 115 kV Switching Station

Figure 7-6
Map of Gas System Infrastructure Plans 2007-2011

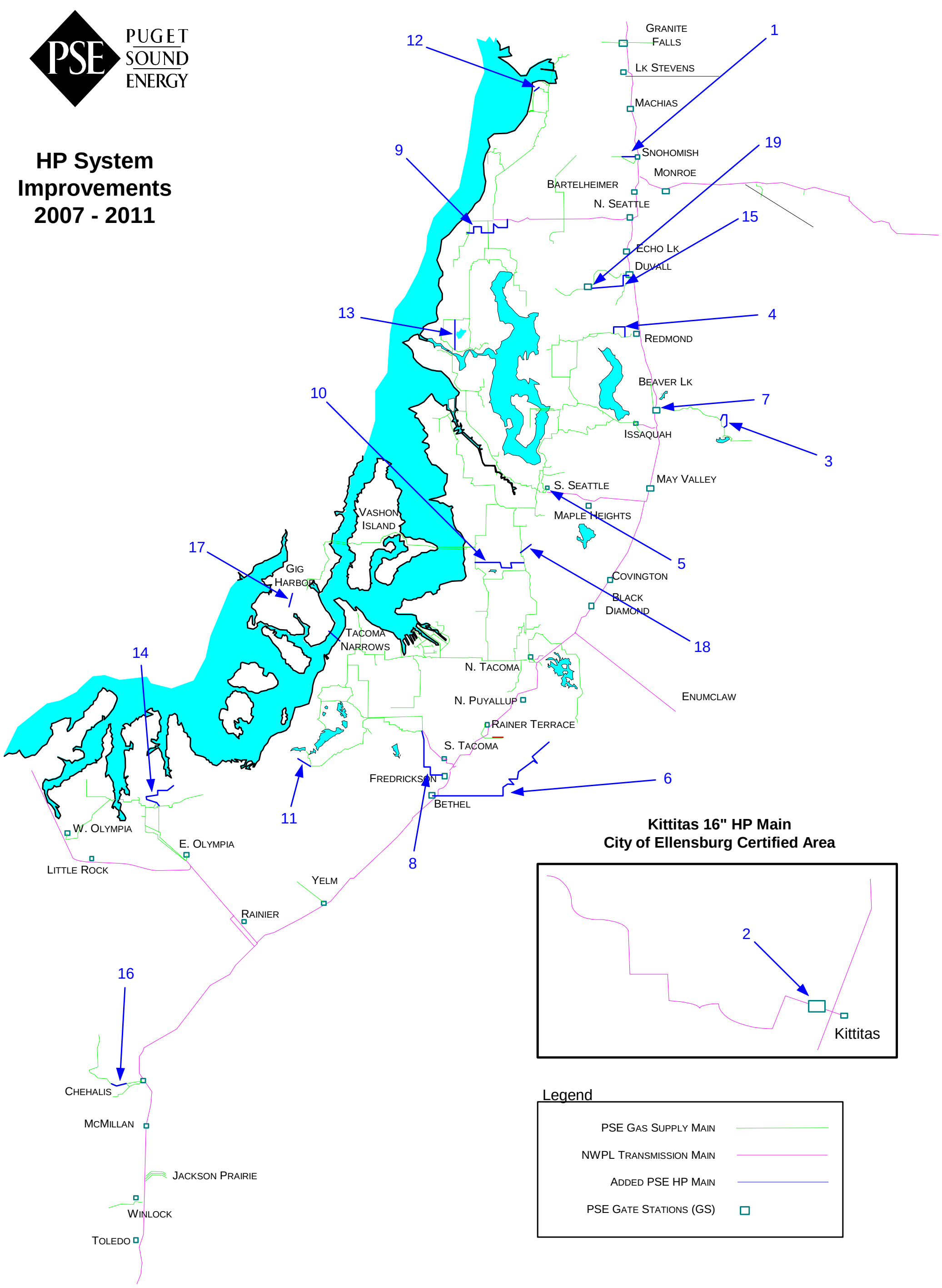


Figure 7-7
List of Gas System Infrastructure Plans 2007-2011

Number	Year	Name of Project	City	Job Description
1	2007	Snohomish	Snohomish	Install ~11,000 feet of 8" HP to replace 4" HP out of Snohomish GS
2	2007	Kittitas Gate Station	Kittitas	Install new higher capacity Kittitas GS and pressure increase lateral to 500 psig
3	2007	Snoqualmie Ph. III	Snoqualmie	Install ~11,500 feet of 12" HP to replace 4" HP on the Beaver Lake GS lateral to North Bend
4	2007	Union Hill Rd. Ph. III	Redmond	Install ~ 8500 feet of 16" HP to connect completed phases I and II ON Bellevue Redmond HP loop
5	2007	S. Seattle Gate Station	Seattle	Rebuild existing S. Seattle GS1376 and 8" Renton Supply DR.
6	2008-2010	Bethel Supply	Bethel	Install 12" HP Bethel GS to serve Cascadia and reinforce areas along the route
7	2008	Beaver Lake Gate Station 2498	Beaver Lake	Rebuild/replace existing GS2498 as required by future flow demands
8	2008	Fredrickson HP Lateral	Fredrickson	Install 12" HP from existing Fredrickson GS to location downstream of S Tacoma TBS.
9	2008	Greenwood Ph. III	Seattle	Install ~25,300 feet of 16" HP from N Seattle TBS to the Fremont and N Seattle LS laterals
10	2008	Kent Black Diamond Ph. II	Kent	Install ~ 27,000 feet of 16" HP from the end of Ph 1b to the Vashon Lateral
11	2009	Dupont HP Extension	Dupont	Extend ~8000 feet of 8" HP from the existing Dupont Supply
12	2009	Everett Supply Loop	Everett	Install 12" HP to connect the two HP Laterals in the Everett area
13	2009	Greenlake Lateral	Seattle	Install ~17,000 feet of 16" HP from the north to the south part of Greenlake Loop, Install new LS at the south loop end
14	2009	N. Lacey Supply	Lacey	Extend ~24,000 feet of 8" HP from existing 12" HP
15	2009	Woodinville Ph. III	Woodinville	Install ~ 26,400 feet of 16" HP from the Woodinville/Duvall GS to DR2134, Investigate new LS installation
16	2009	Chehalis	Chehalis	Replace ~6000 feet of 4" HP with 8" HP and retire 6 DR's, downrate remaining 4" HP to IP
17	2010	Gig Harbor HP Extension from LNG	Gig Harbor	Install 8" HP to southern Gig Harbor supplied from the Gig Harbor LNG facility
18	2011	Renton 8" HP Reinforcement	Renton	Install ~2500 feet of 8" HP to replace 4" HP to DR2521 in the Renton area
19	2011	Woodinville Limit Station	Woodinville	Install new LS off of Duval GS and increase new Woodinville Ph III lateral pressure to 400 psig.

II. Changes and Challenges

Aging infrastructure, changes in the industry and increasing sensitivity to energy costs, electric system reliability and environmental impact make planning delivery systems an evolving and complicated process. The planning process itself is subject to increasing scrutiny following the Northeast and upper Midwest blackout of 2003. Pipeline safety regulations are changing. Throughout the industry, infrastructure investments are rising as infrastructure nears the end of its usable life, and in response to the industry's limited spending during the push for utility deregulation (when facility ownership and cost recovery were uncertain). These changes, combined with the region's strong growth rate and our commitment to keeping gas and electric networks flexible enough to meet changing operating conditions and future needs, are resulting in significant delivery system investments by PSE.

A. General Infrastructure Needs

Electrical and gas equipment installed many years ago is now part of an aging infrastructure. Some components of our gas delivery system have been operating since 1889, and some electric-related equipment since 1917. We review the performance and reliability of these systems continually to ensure safe and reliable operation and to reduce leaks and outages. We have developed programs and processes to maintain existing facilities and add new components as necessary. In addition, aging cast iron mains, bare steel mains, power poles, underground cables, substation transformers and circuit breakers are being systematically replaced under multiyear replacement programs. Finally, we make investments to respond to changing conditions and needs. Annual performance issues for smaller distribution systems can often be resolved within a year or two, but large distribution or transmission issues take much longer to resolve. For example, securing substations and transmission facilities can take more than a decade.

B. Changing Regulations

The blackouts that affected the Northeast and Midwest in 2003 continue to generate changes for electric utilities. New regulations, mandated by The Energy Policy Act of 2005 and developed by the North American Electric Reliability Council (NERC), will go into effect June 1, 2007. Triggered by concern about the electrical grid's reliability, they move the industry into an era in which system planning, performance and operating requirements are mandated and take place under increasing scrutiny. More than 83 out of 107 proposed standards are expected to be adopted. The Federal Energy Regulatory Commission (FERC) selected NERC as the nation's Electric Reliability Organization (ERO). Per the Act, the ERO will be responsible for enforcing the new standards. The Western Electric Coordinating Council (WECC) is working with NERC to implement the new requirements; PSE is preparing to comply fully with them.

The Pipeline Safety Improvement Act (PSIA) of 2002 enacted stricter pipeline integrity requirements for the natural gas industry. As a result, PSE implemented its own transmission integrity management program in 2005 in order to comply with the act and to place additional focus on the transmission pipelines.

Last December, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 was signed into law. The Act reauthorizes and amends the Department of Transportation's pipeline safety programs, and directs the Pipeline and Hazardous Materials Safety Administration to implement a distribution integrity management program (DIMP). Under the rule, concepts from the PSIA of 2002 will be applied to place additional focus on natural gas distribution systems. We anticipate the need to develop and implement our own DIMP by the end of 2009.

C. Right-of-way Issues

We anticipate that right-of-way issues will become more challenging in the future. The cost and effort to acquire these new rights-of-way is rising, and communities are increasingly concerned about their impacts. For these reasons, PSE strives to maximize our use of existing company-owned and public rights-of-way before considering creation of new ones. When we must seek new acquisitions, we believe it is crucial to seek input from the communities and jurisdictions they will affect before finalizing line routing and design. Maintenance of rights-of-way is an ongoing responsibility, and PSE is implementing more stringent vegetation standards for certain right-of-way corridors in accordance with new NERC requirements.

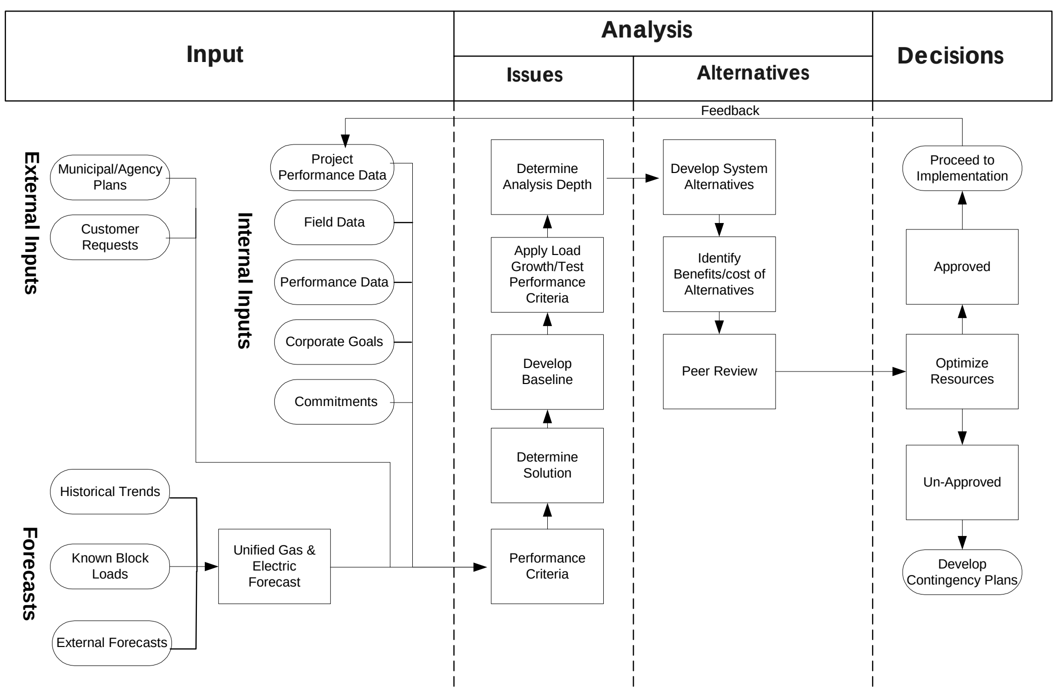
D. Emerging Alternatives

PSE is closely watching the development of new technologies that offer "non-wires" solutions to transmission and distribution challenges. Distributed energy resources technology has the potential to increase capacity on the system by incorporating power that is generated closer to, or at, the customer's location. It has promise, despite a variety of operating characteristics and complexities that must be addressed before it can be reliably integrated into the larger delivery system. Also, regardless of a customer's ability to self-produce generation, PSE must maintain a system equipped to meet use and capacity requirements if the distributed resource is unable to meet the customer's needs. See Section 5 of this chapter for a more detailed discussion of emerging alternatives.

III. Planning Process

The goal of the delivery system planning process is to find cost-effective ways to meet constituent needs. The process begins with an analysis of the current situation and an understanding of the existing operational and reliability challenges. Planning considerations (inputs) include both internal and external factors, load forecasts, customer expectations, and the impact of one energy type on the other. An analysis is conducted to identify alternatives that will address the challenge. Benefits and costs are then forecasted for each alternative that meets the performance criteria. Lastly, planners select and plan for the alternative that best balances customer needs, company economic parameters, and local and regional plan integration. Figure 7-8 diagrams the planning process.

Figure 7-8
Diagram of Delivery System Planning Process



A. Inputs

Internal planning considerations, or inputs, include system performance, company goals and commitments, and load forecasts.

PSE gathers system performance information from field charts, remote telemetry units, supervisory control and data acquisition equipment (SCADA), employees, and customers. Some information is analyzed over multiple years rather than a single year to normalize the effect of variables that can change significantly from year to year, such as weather. For near-term load forecasting at the local city, circuit, or neighborhood level, we use system peak-load and customer growth trends augmented by permitted construction activity for the next two years. For longer-term forecasting we use a corporate econometric forecasting method, which includes population growth and employment data by county (see Chapter 3).

External inputs include regulations, municipal and utility improvement plans, and customer feedback.

Reviewing municipal and utility improvement plans regularly enables us to minimize costs by scheduling upgrades or installation of new infrastructure when the ground is already being impacted by other construction work. We coordinate with other utilities whenever possible, and we work with other outside entities as well to find mutually beneficial schedules. Although our intent is to fully use existing assets before adding new ones, sometimes cost advantages can be gained from early installation for future needs.

PSE collects customer feedback in many ways. We continually investigate customer complaints and track ongoing service issues as they are communicated to us. Customers receive follow-up correspondence to discuss their concern, as well as plans for resolution. This communication provides valuable information that field data or statistical modeling may not have revealed. We also conduct customer surveys to seek out general information regarding customer expectations and possible specific concerns. The feedback from a January 2004 survey of electric customers who were affected by two large storms provided tremendous information that helped validate customer expectations and caused us to refine some of our plans. PSE is reviewing its response to the unprecedented storms of December 2006 to identify additional opportunities for improvement.

B. Performance Criteria

PSE primarily categorizes system needs as "capacity" and "reliability." These performance criteria lie at the heart of our planning process, and along with state and federal requirements provide the foundation for planning our infrastructure improvements.

Figure 7-9
Performance Criteria for Electric and Gas Delivery Systems

Electric delivery system performance criteria are defined by:	Gas delivery system performance criteria are defined by:
Safety and compliance	Safety and compliance
The temperature at which the system is expected to perform	The temperature at which the system is expected to perform
The nature of service and level of reliability that each type of customer is contracted for	The nature of service each type of customer is contracted for (interruptible vs. firm)
The minimum voltage that must be maintained in the system	The minimum pressure that must be maintained in the system
The maximum voltage acceptable in the system	The maximum pressure acceptable in the system
The cost customers are willing to pay for target levels of performance	The cost customers are willing to pay for target levels of performance
The interconnectivity with other utility systems and resulting requirements	

Modeling Tools

PSE relies on many different tools during the planning process to help identify and weigh the benefits of alternative actions. To evaluate both our gas and electric system performance, we use sophisticated modeling software that incorporates field data, including real-time information. Figure 7-10 provides a brief list of these tools, the planning considerations (inputs) that go into each, and the results (outputs) that they produce.

Figure 7-10
Summary of Delivery System Planning Tools

Tool	Use	Inputs	Outputs
Advantica SynerGEE	Network Modeling	Gas and Electric distribution infrastructure and load characteristics	Predicted system performance
Power World Simulator - Power Flow	Network Modeling	Electric transmission infrastructure and load/generation characteristics	Predicted system performance
PSS/E Power Flow & Stability	Network Modeling	Electric transmission infrastructure and load/generation characteristics	Predicted system performance
PSLF Power Flow & Stability	Network Modeling	Electric transmission infrastructure and load/generation characteristics	Predicted system performance
Probabilistic Spreadsheet	Probabilistic Analysis	Outage history, equipment failure probabilities	Outage savings based on probability of occurrence
Estimated Unserved Energy	Unserved Energy	Growth/load at specific conditions, annual load profile	Annual unserved energy, O&M costs as a result, value of service in cost terms
Investment Decision Optimization Tool (iDOT)	Project Data Storage & Portfolio Optimization	Project scope, budget, justification, alternatives and benefits; Resources/financial constraints	Optimized project portfolio, benefit cost ratio for each project, project scoping document
Area Investment Model (AIM)	Financial Analysis	Project costs, 8760 load data; and load growth scenarios	NPV; Income statement; Load Growth vs Capacity comparisons; EUE

PSE’s gas system model is one of the largest integrated system models in the United States. It uses an Advantica SynerGEE software application that is continually updated to reflect new customer loads and system and operational changes. The accuracy of its results is validated by comparing them to actual system performance data. This model helps predict capacity constraints and subsequent system performance on a variety of degree days and under a variety of load growth scenarios. Where issues surface, the model can be used to evaluate alternatives and their effectiveness in resolving the issues. We augment these alternatives with cost estimates and feasibility analysis to identify the lowest reasonable cost solution for both current and future loads.

For our electric distribution system, PSE also uses Advantica SynerGEE software. Here, the feeder system is modeled regionally rather than as a single large model. This is due to the limited connectivity between regions and the complexities with the management of a single large system model. Again, we use the model to evaluate system performance and predict capacity constraints on a variety of degree days and under a variety of load growth scenarios. As software capability improves, we hope to unify our gas and electric models. This will help us meet our customers' energy needs better by increasing our ability to take advantage of cost-effective fuel-switching opportunities where our electric and natural gas service territories overlap.

Modeling begins with building a digital map of the infrastructure and its operational characteristics. For gas, these include the diameter, roughness and length of the pipe, connecting equipment, regulating station equipment and operating pressure. For electric infrastructure, these include conductor cross-sectional area, resistance, length, construction type, connecting equipment, transformer equipment and voltage settings. Next, we identify customer loads, either specifically (for large customers) or as block loads for address ranges. Existing customer loads come from PSE's customer information system (CLX) or actual circuit readings. Finally, we vary temperature conditions, types of customers (interruptible vs. firm), time of peak daily usage, and the status of components (valves or switches closed or open) to model scenarios of infrastructure or operational adjustments to find the optimal solution to a given issue.

To simulate the performance of the electric transmission system, PSE uses three different programs: Power World Simulator, PSS/E (from Power Technologies Inc.), and PSLF (from General Electric). These simulation programs use a transmission system model that spans 11 western states, 2 provinces in western Canada and parts of northern Mexico. The power flow and stability data for these models is collected, coordinated, and distributed through regional organizations including Northwest Power Pool (NWPP) and Western Electricity Coordinating Council (WECC), one of 8 regional reliability organizations under the North American Reliability Corporation (NERC). These power system study programs support PSE's planning process and facilitate demonstration of compliance with reliability performance standards set forth by WECC and NERC. We are discontinuing use of the Managing and Utilizing System Transmission (MUST) program, another PTI product, because its capability to study the system's ability to move power from one area to another under various conditions is included in the Power World Simulator program.

C. System Alternatives

A variety of approaches are available to address delivery system capacity and reliability issues. Each alternative has its own costs, benefits, challenges and risks. These alternatives include the following.

Figure 7-1
Alternatives for Addressing Delivery System Capacity and Reliability Issues

<u>Electric</u>
- Add energy source
  - Substation
- Strengthen feed to local area
  - New conductor
  - Replace conductor
- Improve existing facility
  - Substation modification
  - Expanded right-of-way
  - Uprate system
  - Rebalance load
  - Modify automatic switching scheme
- Load Reduction
  - Distributed Energy Resource
  - Fuel Switching
  - Conservation
  - Load control equipment
  - Possible new tarriffs
- Do nothing

<u>Gas</u>
- Add energy source
  - City-gate station
  - District regulator
- Strengthen feed to local area
  - New high pressure main
  - New intermediate pressure main
  - Replace main
- Improve existing facility
  - Regulation equipment modification
  - Uprate system
- Load Reduction
  - Fuel Switching
  - Conservation
  - Load Control Equipment
  - Possible new tarriffs
- Do nothing

When issues are short term, like peaking events or meeting needs until a construction project is finished, energy flow can be managed temporarily with some of the same alternatives. Examples include:

- Temporary adjustment of regulator station operating pressure, as executed through PSE’s Cold Weather Action Plan.
- Temporary adjustment of substation transformer operating voltage, as done using load tap changers to alter turn ratios.
- Automatic capacitor bank switching to optimize VAR consumption and maintain adequate voltage.
- Temporary siting of mobile equipment such as compressed natural gas injection vehicles, liquid natural gas injection vehicles, mobile substations, and portable generation.

D. Optimizing Value

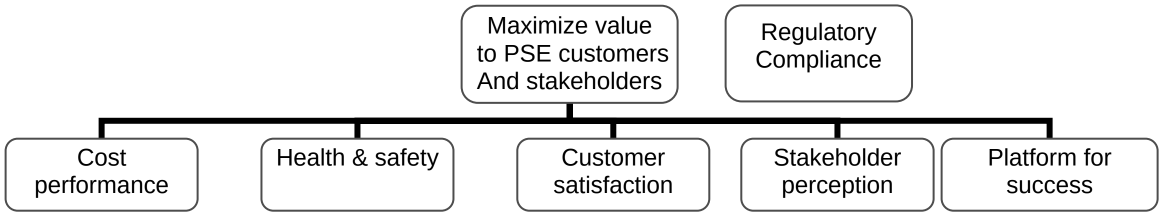
Making prudent investment decisions for hundreds of our gas and electric projects requires an objective way to synthesize, analyze, and optimize projects to maximize value to the company, customers, and the community. For this purpose, we use value-based budget prioritization.

In 2005, we updated the T&D Asset Investment Optimization System to better reflect our objectives, strategy and goals in light of the changing business environment, and to more efficiently and accurately quantify the value of projects, justify funding needs, prioritize projects, and account for risk and uncertainty. Formal “value modeling” refines and integrates existing tools to prioritize projects based on a measure of project value. Project value is estimated by simulating project impacts over the asset life or duration of maintenance funding and applying multi-attribute utility theory. The model we use, Investment Decision Optimization Tool (iDOT), identifies—from any portfolio of possible delivery system capital and maintenance projects, and any constraints on budget-year costs—the set of projects that will create maximum value.

Project costs are calculated using a variety of tools, including historical cost analysis and unit pricing models based on service provider contracts. As projects move through detailed scoping, cost estimates are refined. Planners use Area Investment Model (AIM) software to calculate a wide range of financial performance indicators for each project—including net present value and rate of return—as well as future revenue potential from capacity gained by a particular solution. This allows further comparisons for infrastructure that will be in service for 30–50 years.

The diagram below shows PSE’s benefit structure to evaluate delivery system projects.

Figure 7-12
Benefit Structure to Evaluate Delivery System Projects



IV. Case Studies

To illustrate the planning process through example, we describe four situations and show how PSE addressed them.

A. Chehalis High-Pressure Gas Distribution System

PSE currently serves the Chehalis and Centralia areas with approximately 30,000 feet of 6" and 20,000 feet of 4" high-pressure (HP) pipeline from the Chehalis Gate Station. This one-way system has no alternate supply at present. The Chehalis/Centralia growth rate since 2000 has averaged 1% per year. The long-term plan for this area has been to replace the high-pressure pipe with large- diameter pipe when growth justified the replacement.

During the investigation we found that, in addition to the capacity issues, a number of older regulator stations fed from this line needed to be rebuilt or eliminated. We sought a solution that would address the capacity and maintenance issues at the same time.

Three projects were proposed:

A. Replace 20,000 feet of existing 4" HP pipe with 8" HP pipe, which would eliminate 16 small regulator stations.
B. Replace about 5,000 feet of existing 4" HP pipe with 8" HP pipe, which would eliminate 3 small regulator stations.
C. Replace about 5,000 feet of existing 4" HP with 8" HP pipe (in a different location), which would eliminate 5 small regulator stations.

All three were evaluated via the planning process to determine which would provide the most value, and therefore represent the best solution.

Project (A) lacked a positive benefit-to-cost ratio because customer growth in the area did not justify 20,000 feet of new 8" HP pipeline. It provided excess future capacity and too few near-term benefits. The cost savings from retiring 16 regulator stations and connecting them to the 4" pipe was not enough to justify such a large expenditure for a limited number of customers.

Project (B) had a positive benefit-to-cost ratio due to the reduced footage (5,000 feet versus 20,000 feet). It could handle the area's increased growth for many years and would eliminate 3 regulator stations.

Project (C), however, had the highest benefit-to-cost ratio. The 5,000 feet of pipe to be replaced retired more of the unmaintainable regulator stations (5 as opposed to 3) with as little replacement pipe as possible—yet still provided for an acceptable amount of future growth. Therefore we funded project (C) to be completed no later than 2008.

When the system reaches its capacity in the future, we will propose replacing another optimized section of 4" HP pipe with 8" HP—probably about 5,000 feet in 2014 or 2015. Completing projects in this manner optimizes costs; reduces the amount of underutilized pipe for the short term; funds current needs; and reduces the risks from incorrectly estimated future load growth.

Figure 7-13
Chehalis High-Pressure Gas Distribution System Alternatives

Alternatives	Capital	NPV 30 Yr	Comments
Project (A) – 20,000' of 8" HP and eliminate 16 regulator stations	$5.6M in 2007 Equal to timed projects below	($4.9M) $560k Capital Cost Avoidance & $12.8k Maintenance Cost Avoidance	Not selected – negative benefit/cost ratio. Increased capacity not needed until later.
Project (B) – 5,000' of 8" HP and eliminate 3 regulator stations	$1.4M in 2007 and $3.2M in 2011 (conservative date)	($1.2M) $105 Capital Cost Avoidance & $2.4k Maint. Cost Avoidance	Not selected - less benefit than version 3.
Project (C) – 5,000' of 8" HP and eliminate 5 regulator stations	$1.4M in 2007 and $3.2M in 2011 (conservative date)	($1.2M) $175k Capital Cost Avoidance & $4k Maint. Cost Avoidance	Selected version – best benefit/cost ratio.

B. Hansville Peninsula Electric Distribution System

The north Kitsap County electric system has experienced capacity issues. PSE began serving the Hansville Peninsula in 1980 via a cable resting on the floor of the Port Gamble Bay water passage between Port Gamble and Little Boston. The Hansville area experienced annual customer growth of 0.5% and a predicted capacity problem by 2005.

We used SynerGEE to model growth and to predict when system capacity would begin to adversely affect performance.

We looked at various options including installing a new underwater cable. However, new facilities could take years to study, design, and permit, so we began planning temporary solutions to prevent overuse and possible failure of the cable—which would leave approximately 2,000 customers without service. As a result, we installed a temporary generator at Hansville that operates during colder days, but this is merely a bridging solution that does not meet the long-term needs of this area. We considered three alternatives in our efforts to identify a long-term solution to this capacity issue:

A. An underwater transmission cable with a substation on the Hansville Peninsula, with costs ranging from $15 to $20 million.
B. A second distribution submarine cable at an estimated cable cost of about $4 million plus additional costs.
C. A new distribution substation and related transmission line, at a cost of about $5 to $7 million. In addition to providing capacity to the peninsula, the new substation would provide future capacity to the town of Kingston.

Alternative (A) was eliminated due to its cost. Alternative (B) meets near-term and long-term demand in Hansville, but does not provide additional capacity for the Kingston area and has more unknown costs for construction and engineering of underground cable. Alternative (C) was selected and is scheduled for completion in 2007. Its estimated cost was approximately equal to alternative (B) but without any additional cost unknowns, and it would provide greater capacity. The temporary generator will still be needed until the substation is completed.

Figure 7-14
Hansville Electric Distribution System Alternatives

Alternatives	Capital	NPV 30 Yr	Comments
Transmission Underwater cable	$15-$20 M	N.A.	Is not cost competitive
Second Distribution underwater cable	$4 M	($6.5M)	Too many cost unknowns to be a viable alternative
Kingston Substation	$5-$7 M	($4.7M)	Least cost alternative with more capacity than the distribution underwater cable

C. Puyallup Intermediate Pressure (IP) System Uprate

IP System #058 is PSE's natural gas distribution system serving the north Puyallup area. Its 300 miles of IP pipes, serving 22,000 customers, currently operate at a maximum allowable operating pressure (MAOP) of 45 psig. Since 2000, customer growth has averaged 2% per year. Using this growth rate and SynerGEE forecasting, we predicted that IP System #058 need would exceed capacity by the 2006-2007 winter season. As a result, more than 800 gas customers would experience outages at 15°F and more than 4,600 customers would experience outages on a design day (10°F). While cold-weather actions would ensure service continuity during the winter of 2006-2007, a more permanent and robust infrastructure solution was needed.

Four alternatives were evaluated to reinforce this area of our natural gas system:

A. IP main replacement-reinforcement alternative—replace more than 45,000 feet of existing 2" and 4" pipe with 6" pipe, install 8,500 feet of 4" pipe, and install 6,000 feet of 6" pipe.
B. HP extension I—install more than 19,000 feet of 8" HP main from the North Puyallup Gate Station and install two district regulators (DR).
C. HP extension II—extend more than 16,500 feet of 8" HP main from an existing 6" HP system and install two DRs.
D. Uprate IP System #058 from 45 psig to 60 psig MAOP.

Option (A) would meet the capacity need until 2012 and cost about $4 million. Option (B) would meet the capacity need until 2011 at an estimated cost of $7.5 million. Option (C) would also meet the capacity need until 2011, but at an estimated cost of $5.3 million. Option (D) would cost about $2.8 million and meet capacity needs until 2014. This option had a larger benefit-to-cost ratio: It was almost 50% less than the other options and would meet capacity concerns for more years. The uprate work began in 2006 and is scheduled to be completed in 2007. We also looked at combinations of alternatives, but from a long-range perspective no combination would be economically feasible and adequately handle growth without including the IP uprate solution.

Figure 7-16
Puyallup System Uprate Alternatives

Alternatives	Capital	NPV 30 Yr	Comments
IP replacement-reinforcement	$4.44M	($3.7M)	Not selected. Meets capacity requirements until 2012.
HP extension I	$7.50M	($6.3M)	Not selected. Meets capacity requirements until 2011.
HP extension II	$5.31M	($4.4M)	Not selected. Meets capacity requirements until 2011.
IP system uprate	$2.82M	($2.0M)	Selected option, least cost solution. Meets capacity requirements until 2014.

V. Emerging Alternatives

In the last 20 years, electricity consumption has increased 2.0% to 2.5% annually in North America. During this time, transmission infrastructure expansions have not taken place at an equivalent rate to match the increasing consumption. As a result, the strain on the transmission system is being felt throughout North America, including the Pacific Northwest, where the main grid transmission system has operated at or near capacity due to a lack of substantial transmission construction between 1987 and 2003.

PSE and the region's utilities have a vested interest in finding an optimal solution to this problem, and we are studying several emerging alternatives to meet today's transmission and distribution challenges. They include distributed energy, demand-response alternatives, and the development of a "smart grid."

A. Distributed Energy Resources

Distributed energy is a way of incorporating small-scale generation into the grid close to where the power is used. Many such sources exist: internal combustion engines, fuel cells, gas turbines and micro-turbines, hydro and micro-hydro applications, photovoltaics, wind energy, solar energy, and waste/biomass. The challenge for the delivery system is how to integrate this power into a system that was designed to transport power from large generating plants located far away.

For much of the 20th century, small-scale customer-based generation could not compete economically with centralized, utility-owned power plants, but those economics have begun to change. Though not yet cheaper than the conventional system in most cases, an increasing variety of customers find small-scale solutions desirable. Some industrial customers want to meet their heating and electrical needs with one system. Hospitals and computer-based internet service firms now require higher levels of power quality and would suffer significant consequences if a service interruption were to occur. Some customers want renewable or green power.

The formal name for distributed energy solutions is distributed energy resources (DER). It includes all technologies in distributed generation (DG), distributed power (DP) and demand-response applications. Unlike the conventional system through which power generally flows in one direction, DER configurations allow power to travel in both directions: Customers who generate electricity for their own use (or have back-up generators standing by) can sell power back to the grid. PSE already has more than 100 such "interconnected" customers. Demand-response applications build two-way communications into the system that enable customers and the company to calibrate actual usage much more closely.

Although a host of regulatory, business practice, technical and market barriers continue to challenge the full-scale implementation of DER technology, PSE believes that it has the potential to provide cost-effective, appropriate and meaningful solutions. We are already incorporating DER elements into our planning process, and have developed guidelines to identify projects most likely to serve as the lowest reasonable cost solution. To ensure no adverse effects on our customers, we require that such solutions be as reliable as traditional "wires-based" projects.

PSE has already implemented some DER solutions, and we are testing others to find out if they can provide benefits that justify their costs.

The Hansville Penninsula project outlined in the Case Studies section of this chapter uses distributed generation to meet the capacity needs of customers while a permanent infrastructure solution is constructed. When the existing submarine cable that supplies electricity to the area approaches its design capacity, the temporary generator is operated. This supplies the additional power needed and protects the cable from failing until the new substation and transmission line are completed.

At Crystal Mountain, PSE implemented a distributed resource peak shaving strategy in 1999 that enabled us to defer a costly traditional system upgrade. The load in the area (which included the Crystal Mountain and Greenwater substations) was projected to increase from 5.9 to 11.2 MVA by 2006-2007. A traditional upgrade was estimated to cost $2.5 million. PSE refurbished a 2.4 MVA diesel standby generator located nearby, tested it to prove both concept and feasibility, and placed it in service to meet the need.

PSE began testing a conservation voltage reduction pilot program in 2006 in conjunction with the Northwest Energy Efficiency Alliance (NEEA). The homes of 10 customers in two locations were fitted with meters capable of monitoring energy usage at the residence and transmitting that information back to PSE every 15 minutes over telephone lines. On alternate days, PSE reduced substation transformer control voltage from a range of 123 to a range of 119 volts. This results in a feeder voltage reduction of 3%. Two-way communication helped us determine whether the reduced voltage adversely affected any customers. Preliminary results from Phase 1 of the study are favorable, indicating 2%

energy savings at both pilot locations with no adverse effects. The NEEA will proceed in getting approval to begin Phase 2.

In its 2006 General Rate Case filing, PSE proposed refinements to our existing Schedule 93 commercial/industrial customer demand buyback tariff, a residential voluntary critical peak pricing pilot, and a voluntary community load curtailment pilot. We will work with the Conservation Resources Advisory Group to finalize design and evaluation plans for demand-response pilots. We will then file for tariffs and approval from the WUTC, initiate an internal implementation process, and recruit and finalize pilot participants. The pilots will then be installed and will collect data through 2009.

B. Modernizing the Grid

Smart grid is a movement to integrate intelligent devices and new technologies into the electrical grid to optimize the system to a degree not possible with existing infrastructure. It is less well developed than DER technologies, but has the potential to integrate all parts of the electric power system—production, transmission, and distribution—in ways that would be extremely beneficial.

- Such a grid would be self-healing, meaning sophisticated grid monitors and controls will anticipate and instantly respond to system problems in order to avoid or mitigate power outages and power quality problems.
- Such a grid would be more secure from physical and cyber threats, because it will be better able to identify and respond to man-made or natural disruptions.
- Such a grid would support widespread use of distributed energy resources, meaning standardized power and communications interfaces will allow customers to interconnect fuel cells, renewable generation, and other small-scale generation on a simple “plug and play” basis.
- Such a grid would enable customers to better control the appliances and equipment in their homes and businesses; the grid will be able to communicate with energy management systems in smart buildings for greater control over energy use and costs.

PSE is monitoring and researching smart grid devices, and participating with various governmental, regional, industry and utility groups in workshops and summits. When these devices become commercially available, we will integrate them into our cost-benefit analysis.

C. DER-related Industry and Regulatory Activity

PSE is monitoring and evaluating DER developments at the federal, state, and utility levels on an ongoing basis. Recent activity includes the following.

Federal and state agencies have taken some steps to address the technical, permitting, interconnection, and regulatory barriers identified in the National Renewables Energy Laboratories (NREL) report issued in May 2000.

The Department of Energy (DOE) established the Electric Distribution Program to work with federal, state, industry, laboratory and university groups on program planning, research, development demonstration and deployment of DER. The program supports a wide variety of distribution grid modernization initiatives and summits.

The DOE's Distributed Energy Resource program has implemented a Distributed Energy Resource Strategic Plan that promotes "next generation" clean, efficient, reliable, and affordable DER technologies.

FERC initiated a Notice of Proposed Rulemaking in July 2003 designed to finalize the standardization of small-generator interconnection agreements and procedures. (This followed FERC's Advance Notice of Proposed Rulemaking and the National Association of Regulatory Utilities Commission's [NARUC] June 2002 release of draft interconnection agreements and procedures.) In October 2003, NARUC published the model agreement for Interconnection and Parallel Operation of Small Distributed Generation Resources as an information tool and to serve as a catalyst for DER interconnection proceedings.

The Institute of Electric and Electronic Engineers (IEEE) is developing specific and voluntary DER standards. IEEE Standard 1547-2003, Standards for Distributed Resource Interconnection with the Electric Power Systems, was established and approved by the IEEE board in June 2003. The IEEE Standards Coordinating Committee is currently drafting and establishing technical guidelines for interconnecting electric power sources greater than 10 MVA with the transmission grid. The IEEE Distributed Resources

Integration working group has issued a draft paper on the impact of DER on utilities. DER should become easier for small customers to implement as many of these standards become finalized and approved.

BPA, which owns and operates approximately three-quarters of the electrical transmission system in the Pacific Northwest, holds Non-Wires Solutions (NWS) Roundtable meetings, in which PSE and other organizations participate. The group—utilities, regulators, renewable resource advocates, environmental interest groups, industrial energy users, Native American tribes and independent power generators—considers broad, regional approaches to employing non-wires solutions.