EXHIBIT NO. ___(SML-22)
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**

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

JULY 3, 2008

ATTACHMENT C to PSE's Response to WUTC Staff Data Request No. 081

PUGET SOUND ENERGY

PSE SYSTEM PERFORMANCE PROGRAMS
2006 Annual Review

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PSE SYSTEM PERFORMANCE PROGRAMS
2006 Annual Review

I. System Performance Programs Overview

The primary goal of PSE's Transmission and Distribution (T & D) system planning is to find cost effective ways to meet customer's needs. We seek to achieve this goal by finding ways to safely, reliably and cost effectively deliver energy in a manner that meets operational, regulatory, environmental, and changing customer requirements.

This report discusses the 2006 performance of our energy delivery system, and provides details on PSE's major programs to manage or improve system performance. These programs include the following:

Gas and Electric Programs

Major Gas Programs	Major Electric Programs
• Gas System Utilization	• Electric System Utilization
• Leakage Reduction	• Electric Reliability
• Third Party Damage Reduction	• Third Party Damage Reduction
• Pipeline Integrity Management	• Tree Watch
• Cast Iron Replacement Program	• Vegetation Management
• Bare Steel Replacement Program	• Mark I Switch replacement
• Critical Bond	• Overhead Outage Reduction
• Isolated Facilities	• Animal Mitigation
• Unmaintainable District Regulators	• Cable Remediation
• Gas System Maintenance	• Transmission Switch
	• Pole Replacement
	• Supervisory Control and Data Acquisition (SCADA)
	• Transmission & Distribution (T & D) Line Maintenance
	• Substation Maintenance

For purposes of continual improvement, Total Energy System Planning (TESP) sets internal goals. Throughout this report, 2006 performance will be evaluated against these internal goals, and 2007 goals are also discussed. In many cases the goals are set at higher performance levels than required by the Service Quality Indices (SQIs) that have been established with the Washington Utilities and Transportation Commission (WUTC). By doing this, we are working to ensure that SQIs and customer needs are met even in years when weather and system conditions may have a significant impact on system performance.

Gas Performance

During the winter of 2006-2007, the gas system performed well. The table below shows a comparison of year 2006 gas system performance with that of the three previous years. While the gas system continues to perform well, several of our internal 2006 goals were not met due to project deferrals to 2007 caused both by external factors (such as permitting) and internal delivery constraints. We reduced the number of Cold Weather Actions[1] (CWA) required at all temperatures, and the number of associated customer curtailments declined as well. For example, under the coldest send out conditions, the number of CWAs dropped from 35 in 2005 to 22 in 2006.

PSE's designed and installed gas infrastructure projects resulted in reduced High Pressure Utilization[2] from 28.3% at the end of 2005 to 22.5% at the end of 2006. Similarly, the Intermediate Pressure Utilization was reduced from 14% to 5.2% for the same time period. In addition, while the number of active leaks increased from 2,535 to 2,660, active leaks per mile held fairly steady. This is primarily due to PSE's aging gas system infrastructure, and because programs like cast iron replacement have already eliminated the majority of large leak concentrations. The remaining leak profile is spread out across the system. More detail of Gas System Performance is included in section II.

Gas Performance Summary

(Annual Data Jan. 1st to Dec 31st)

	2003	2004	2005	2006 Goal	2006 Actual
Active Leaks per mile of main	0.26	0.22	0.22	0.17	0.23
Active Leaks	2,864	2,493	2,535	1,975	2,660
Cold Weather Actions at 120 to 124MMcf*	11	7	6	4	3
Cold Weather Actions at 140 to 144MMcf*	38	33	20	N/A	17
Gas System Utilization (HP)	95.1%	93.7%	28.3%**	13.5%	22.5%
Gas System Utilization (IP)	N/A	N/A	14.0%**	2.5%	5.2%
Third Party Damage per locate request	0.80**	1.27%	1.16%	N/A	1.16%

*Does not include Gig Harbor LNG. **See Gas System Utilization section for new methodology.

*** Percentage is for both gas and electric Third Party Damage statistics.

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[1] Cold Weather Actions are actions taken by staff during cold weather to maintain gas delivery pressure to firm customers, such as injection and bypass actions.

[2] High pressure and low pressure utilization is a measure of the percent of the system that operates at below design pressure criteria during a design day.

Electric Performance

The 2006 performance of the electric system in comparison with previous years is summarized below. In 2006, we met our Service Quality Index for the System Average Interruption Frequency Index (SAIFI), which is set at 1.3. Electric system reliability did not meet the Service Quality Index for System Average Interruption Duration Index (SAIDI) which is set at 136. Our internal goals for SAIFI (set at 1.0) and SAIDI (set at 110) were missed by 23% and 114% respectively. These results represent a change from past years where internal SAIDI and SAIFI goals were achieved, and are attributed to multiple weather events described by the Seattle Times[3] as "a year's worth of wicked weather. In addition to the massive windstorm of December 14, many other weather events occurred throughout the year. These storms caused widespread property damage in the communities we serve, exceeded the design capabilities of PSE's electrical system, and required that we open the Emergency Operations Center nearly 20 times in a single year.

Electric Performance Summary

(Annual Data Jan. 1st to Dec 31st)

	2002	2003	2004	2005	2006 Goal	2006 Actual
Non-Storm Outage Duration – SAIDI*	106	173	113	129	136	215
Non-Storm Outage Frequency – SAIFI*	0.83	0.80	0.77	0.94	1.30	1.23
Electric System Utilization	85.5%	84.9%	85.6%	85.5%	85.4%	86.1%
Third Party Damage	1.02**	0.80**	0.49%	0.44%	Not Available	0.55%

*SAIDI: System Average Interruption Duration Index – average outage minutes/customer per year, SAIFI: System Average Interruption Frequency Index – average number of outages/customer per year. Both indices exclude major events where 5% or more of customers are out of service.

**Percentage is for both gas & electric Third Party Damage statistics.

As a case in point, there were approximately the same number of localized non-Major weather-related emergency events in 2006 as in 2003, 2004 and 2005 combined; more weather events were recorded in 2006 alone than the previous four years (2002-2005). Once we've reviewed our response to these weather events and evaluated what can be done to modify sections of our electric system to improve performance, we will be considering infrastructure additions or modifications. IEEE survey data shows that PSE remains in the top XXX% of performance for SAIFI, and the top XXX% for SAIDI. (Note: XXX values available from IEEE in May/June 2007.)

Our internal 2006 electric utilization goal was 85.4%. Capacity improvements included three new substations and upgrades to an additional three substations, for a total added capacity of 136 MVA. Capacity projects planned from 2006 through 2008 are projected

[3] Lynda V. Mapes, "A year's worth of wicked weather", The Seattle Times, January 1, 2007, Sec. Local News. Also taken from "PSE Service Quality Program Filing", February 15, 2007, page 6.

to maintain the electric utilization at approximately 85.0%. Third Party Damage per locate request rose from 0.437% in 2005 to 0.551% in 2006. This rise can be attributed to the increasing amount of underground cable in urban areas. Section III provides more detail on Electric System Performance.

Key Performance Indicators

Metrics, discussed above are one vehicle to assess overall gas and electric system performance. PSE also measures performance against Key Performance Indicators (KPIs) to monitor, at a detailed level, the impact of our system maintenance and reinforcement programs. We then communicate the results to others. In 2006, we were generally satisfied with the KPIs. For example, replacement programs continued to meet expectations set by the WUTC, new programs (such as Isolated Facilities) were implemented to assess aging infrastructure, and other programs, such as vegetation management and substation maintenance, positively impacted SAIDI and SAIFI.

The following provides a snapshot and historical comparison of the KPIs associated with the programs outlined on page 4.

Gas Programs	2004	2005	2006
Pipeline Integrity Management: Assess transmission lines in High Consequence Areas	.3 miles of transmission line	1.6 miles of transmission line	3.1 miles of transmission line
Cast Iron Main Replacement: Replace Aging Pipe with Polyethelene Pipe	105,079 feet (25,079 over target)	62,539 feet (13,303 over target)	79,275 feet (725 under target)
Bare Steel Main Replacement: Replace Aging Pipe with Polyethylene Pipe	37,200 feet	50,378 feet	88,624 feet
Critical Bond: Review and Remediate Cathodic Protection (CP) System	2,713/3,511 relative to adequate CP sites, 479/502 of the regulator stations	2,806/3,305 relative to adequate CP sites, 502/502 of the regulator stations	3,015/3,299 relative to adequate CP sites, 502/502 of the regulator stations
Gas System Maintenance: Complete preventative and mandated maintenance tasks on gas facilities	N/A	100 programs	108 programs

Electric Programs	2004	2005	2006
TreeWatch: Perform TreeWatch and remove dying trees	836 miles 18,600 dying trees	600 miles	13,853 dying trees
Vegetation Management: Cyclical tree trimming, herbicides, tree removal & hot spotting	2,198 miles of distribution system, 709 miles of transmission and high voltage distribution system	1,909 miles of distribution system, 682 miles of transmission and high voltage distribution system	1,656 miles of distribution system, 694 miles of transmission and high voltage distribution system
Overhead Outage Reduction: Replace bare OH conductor with TreeWire (insulated conductor)	106,900 feet	311,046 feet	150,845 feet
Mark I Switch Replacement: Replace or eliminate obsolete switches	10	16	12
Animal Mitigation: Install animal guards in areas with large numbers of wildlife-related interruptions	1,661	2,400	1,900
Cable Remediation: Replace, inject or abandon aging underground primary cables	184 miles	124 miles	96 miles
Transmission Switch: Replace transmission line switches to prevent failure in service	not available	22 switches replaced 24 switches maintained 6 switches removed	7 switches replaced 36 switches maintained 1 switches removed
Pole Replacement: Replace aging distribution & transmission poles	not available	347 distribution poles replaced 142 transmission poles replaced	517 distribution poles replaced 224 transmission poles replaced
SCADA: Install SCADA to monitor & control substation equipment	5 SCADA systems put in service	7 SCADA systems put in service	32 SCADA systems put in service
T&D Line Maintenance: Complete preventative maintenance tasks on transmission & distribution line equipment	not available	3 programs 17 structures	3 programs 23 structures 8 cable signs
Substation Maintenance: Complete preventive maintenance tasks on substations	9,000 4.7% resulted in corrective maintenance	7,771 12.58% resulted in corrective maintenance	9,492 8.52% resulted in corrective maintenance

Overview of 2007 Budget and Priorities

PSE improves system performance by setting specific system targets and providing the funding for the projects and programs that support these targets. In late 2006, we began building on our goal-setting efforts of past years, which involved the following: developing detailed business cases to recommend targets for several system performance related KPIs; explaining the funding and customer services impacts of these recommendations; and ultimately, sharing this information with others who contribute to the construction of our system plans. A more detailed discussion on this work can be found in Section XXXXXXXXXX.

As in past years, growth and reliability projects, along with other construction work for the 2007 Operations Capital Budget were prioritized based on the Total Energy System Planning (TESP) Process. This process measures the benefits vs. costs of a given project with very detailed analytics and allows us to make the most prudent investment decisions from a portfolio of hundreds of gas and electric projects. The result is that all electric and gas projects are compared against one another, with an emphasis on maximizing the benefits across the project portfolio while meeting budget targets for spending.

The following table is a comparison of PSE's capital budget actuals for 2005, 2006 and the 2007 budget.

Capital Budget Targets 2005-2007

	2005 Cap Actuals (in Million)	2006 Cap Actuals (in Million)	2007 Cap Budget (in Million)
Customer Reimbursement	$3.3	$4.1	$3.8
External Commitment	$24.3	$28.5	$33.7
Growth: Increase Capacity	$62.3	$95.7	$105.4
New Business – Services	$96.8	$105.0	$106.6
Reliability Maintenance, Unplanned	$16.3	$23.9	$13.5
Reliability Maintenance, Planned	$80.0	$86.7	$95.0
Other	$2.8	$6.2	$3.8
Grand Total	$285.8	$350.1	$361.8

Over the next five to ten years, PSE plans to implement projects at an increasing level of investment due to growing demand for energy, aging infrastructure, continued focus on reliability, and evolving compliance requirements. PSE will strive to:

- Maintain SAIFI while focusing greater efforts on reducing SAIDI.
- Maintain steady Electric Utilization while driving Gas Utilization down to balance CWA and curtailments.
- Reduce leakage on the gas system.
- Consider equipment replacement, when appropriate, to manage maintenance needs for aging infrastructure.
- Maintain compliance with evolving gas safety regulations and NERC Reliability Standards.

As these drivers and performance expectations evolve, we will continue to rely on – and adapt as necessary – our energy delivery infrastructure planning and budgeting process to optimize benefits, manage costs, and maintain a balance between customer and shareholder needs. In addition, PSE will need to increase its delivery capacity, including both contracted and delivery resources to meet future challenges.

The following table provides further detail on PSE's T&D reliability programs and their expected benefits. Benefits either improve service to customers; result in the proactive monitoring of the infrastructure for proper operation, or lead to the maintenance of components for proper functioning.

	2006 Actual (in millions)	2007 Budget (in millions)	2007 Expected Benefits	
Cable Remediation	$ 15.3	$ 14.0	154,738 customers out	5,665,680 minutes saved
Electric Distribution Reliability[1]	$ 9.4	$ 10.8	55,230 customers out	9,960,748 minutes saved
Transmission Reliability[2]	$ 2.5	$ 0.7	200,913 outages	24,595,731 minutes saved
Animal Mitigation	$ 0.4	$ 0.3	600 units protected*	240 minutes
Substation Reliability	$ 8.0	$ 19.4	146,789 outages	4,726,939 minutes
Cast Iron Replacement	$ 6.7	$ 2.3	87 leaks saved	---
Bare Steel Replacement	$ 7.1	$ 7.9	130 leaks saved	---
Critical Bond	$ 10.1	$ 8.8	3,015 CP systems*	502 regulator stations
Gas Reliability[6]	$ 34.0	$ 2.4	750,000 outages	---
Total Capital	**$ 93.5**	**$ 66.6**		
Electric Maintenance[4]	$ 0.6	$ 0.5	19,151 outages	1,254,700 minutes saved
Animal Mitigation	$ 0.1	$ 0.1	389 outages	41,755 minutes saved
Gas Maintenance[5]	$ 16.5	$ 18.2	730 valve repairs 608 B & C leak repairs	---
Substation Maintenance	$ 4.5	$ 4.7	804,733 outages	99,689,234 minutes saved
Vegetation Management	$ 8.4	$ 8.5	99,529 outages	5,206,728 minutes saved
TreeWatch	$ 2.0	$ 2.0	18,000 trees removed/trimmed*	---
Total O & M	**$ 32.1**	**$ 34.0**		

*Programs for which benefits are still under development.

1 Electric Distribution Reliability includes programs such as Targeted Outage Reduction, SCADA, Pole Replacement and Mark I Switch Replacement. It also includes Distribution System Rebuild, and Distribution Outage Duration, not specifically mentioned in the report.

2 Transmission Reliability includes programs such as Transmission Outage Frequency, Transmission Outage Duration, and Pole Replacement.

3 The Original TreeWatch Program formally ended in 02/05. TreeWatch continues as an O&M program primarily focused on transmission corridors.

4 Electric Maintenance includes Trans Switch Maint, Ebey Slough Dike Maint, Trans Aerial Inspection, Trans Pole Inspection, Transmission Insulator Replacement, Submarine Cable Sign, Cable Concentric Neutral Testing, Pole Inspection & Treatment, and Avian Protection.

5 Gas Maintenance includes Leak Survey & Patrols, Inspections & Maint Stations, Valve Maint, Leak Repair, Valve Locate & Operate, Leak Monitoring, Atmospheric Remediation, ECATS/AMR Inspections, RTU Inspections, Suburban Gauge Inspection, Inside Meter Survey, Unmaintainable DR & Facilities, Integrity Mgmt, Farm Tap Inspection & Testing, LNG Satellite Inspections & Repair, Mater Meter Inspection Maint., Industrial Meter Changes & Pipeline Markers.

6. Gas Reliability includes some capacity projects due to imminent outages versus meeting future growth needs.

Electric projects aimed at reducing outage duration (improving SAIDI) include the continued funding of SCADA, recloser and cable remediation projects. Electric projects that will reduce the number of outages (improving SAIFI) include tree wire, copper replacement and underground cable replacement.

In 2007, PSE continues to fund gas reliability programs. These programs include replacing additional cast iron and bare steel to reduce leakage, and construction of several major gas infrastructure projects that will provide substantial capacity to serve demand, eliminate or reduce CWA, and improve gas system utilization.

The 2007 funding level of $102.7 million for projects that address utilization will support the construction of a number of significant projects:

- Three large pressure uprates in Edmonds, Bellevue, and Tacoma.
- New HP and IP projects including 25,000′ of 16″ HP for the Kent/Black Diamond project, 11,000′ of 8″ HP for the Snohomish project, 7250′ of 12″ HP for the Central Seattle project and a 2nd LNG Tank for Gig Harbor.
- Seven new distribution substations including Boeing Aerospace, Chimacum, Christopher, Glencarin, Kingston, Mt. Si, and Serwold.
- Five rebuild/expansions of existing distribution substations including Weyerhauser, Paccar, Prine, Sehome, and Friendly Grove.

Innovations, Initiatives, & Challenges

PSE strives to maintain its edge in providing safe reliable energy service at low cost. Innovative thinking and industry activities will help drive PSE to continue to be a best-in-class performer. Several key areas of activity include:

- **Automatic Meter Reading** We will continue to build and test enhancements to the Meter Data Warehouse (MDW). By increasing functionality, we'll be able to better manage the metering system and to provide data to groups outside of the standard meter reading process. AMR enhancements that will aid T & D planning include: updated outage interpretation, including advanced mapping of outages; integration with PSE's outage tracking system; a real-time dashboard of outage status by county; and improved restoration verification tools.

- **Customer Care** PSE recorded 19 reliability complaints and four power quality inquiries in 2006, while the WUTC reported directly receiving an additional 56 reliability complaints. This total of 79 reliability/power quality complaints for 2006 surpasses the 2005 total of 53. We continue to respond to each and every complaint on an individualized basis.

- **SmartGrid – Modernizing the Grid** SmartGrid 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. While the development of SmartGrid lags behind Distributed Energy Resources (DER) technologies, it has the potential to integrate all parts of the electric power system – including production, transmission and distribution – in ways that would be extremely beneficial.

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

- **Engineering Matters** This PSE employee group that meets monthly to present and listen to internal and external speakers. It provides an opportunity for training and professional growth, and helps keep the engineering teams as abreast of external developments as possible.

- **Total Energy System (TES) Process** The T&D Asset Investment Optimization System was updated in 2006 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. The improved analytics and web-based portfolio management system will help drive system improvements for years to come.

- **Distributed Energy Resources** PSE is monitoring and evaluating DER developments at the federal, state, and utility levels on an ongoing basis.

- **Distribution Integrity Management** In 2006, the Pipeline and Hazardous Materials Safety Administration (PHMSA) developed a high level flexible regulation for distribution integrity management, and its Gas Pipeline Technical Committee (GPTC) is drafting Distribution Integrity Management Program (DIMP) Guide Material to be incorporated by reference in the federal rule.

  In 2007, PSE will work to fully understand the requirements of the rule by forming a project team to identify and evaluate DIMP compliance options. Additionally, the team will begin work on recommended solutions, schedules and plans to ensure we meet DIMP compliance deadlines.

- **Future Performance Targets** Total Energy System Planning (TESP) and System Maintenance Planning (SMP) are developing business cases focused on several measures of delivery system performance. This work builds on efforts begun in 2004, when the teams set high level system performance targets to focus asset management efforts and support high level spending targets. Since 2006, we've worked to complete business cases for Electric System SAIDI, SAIFI, Electric System Utilization, Gas System Utilization for High Pressure Piping and Gas System Utilization for Intermediate Pressure Piping. These business cases are being developed to a more detailed resolution than ever before, and will be communicated by mid 2007.

Conclusion

The PSE system performed well considering the challenges faced in 2006. These challenges include the number and severity of storms, external constraints (such as permitting) and internal delivery and resource constraints. As one comparator, in 2006 the Emergency Operations Center was opened twice as much as previous years which diverted resources needed for project development and delivery.

The gas system performed well in 2006 with improvements in both cold weather actions and customer curtailments needed to maintain system pressure. System utilization was improved by the installation of capacity projects. The Cast Iron Replacement Program will conclude in 2007, but other existing gas system improvement programs will continue. A new program, Wrapped Steel Service Assessment Program (WSSAP), is being added in 2007.

The electrical system performance was defined by the 2006 storms. All metrics experienced increases. The SAIFI target was met, but SAIDI and electric utilization targets were not. While we believe that 2006 storm frequency and severity was an anomaly, we are nevertheless continuing to monitor trends and plan system hardening as if it were not an anomaly. Our existing programs will continue to maintain performance levels to below normal target levels. However, these programs have reached their maximum effectiveness, and we are working to revise and improve electric reliability strategy and performance even further.

To these ends, in 2006 and early 2007, TESP has developed business cases for five system performance targets. One outcome from this effort that will change electrical reliability performance is a focus placed on SAIDI improvements. The business case justified increases in electrical reliability budget and created a Suite of Solutions that distribution planners can use to reduce SAIDI. In addition, TESP recommends additional improvements to improve electric and gas system utilization, and to maintain SAIFI performance. These new five-year objectives and business plan documents for hardening PSE's system are available under separate cover.

In addition, in response to the large December 2006 windstorm, PSE is currently undertaking a comprehensive review of its operational and infrastructure systems. Using both external consulting and internal resources, additional opportunities for "hardening" the system against future storms -- including both infrastructure and operational solutions to meet customer expectations -- will be identified in the upcoming months.

II. Gas System Performance

Overview

PSE employs several programs and plans to ensure safe and reliable operation of the gas system. These include efforts to improve the overall reliability of the gas system by reducing the chance of outages due to cold weather and reducing leaks on the system:

- ♦ Outage Prevention Programs/Plans
  - Gas System Utilization/ Cold Weather Action (CWA) Plan
- ♦ Leak Reduction Programs/Plans
  - Third Party Damage Prevention Program
  - Leak Reduction Performance
  - Pipeline Integrity Management
  - Cast Iron and Bare Steel Replacement
  - Critical Bond
  - Isolated Facilities Programs
  - Wrapped Steel Service Assessment Program
  - Unmaintainable District Regulator Remediation Program
  - Gas System Maintenance

The table below shows several methods for evaluating system performance. System utilization measures the overall performance of our gas piping system from a capacity standpoint. It is calculated as the percentage of the gas system piping, on a footage basis, which is expected to operate at pressures below design criteria on a design day. The calculation is based on the SynerGEE Gas Model. Separate metrics are calculated for the intermediate pressure system and the high pressure system. Gas system performance is evaluated by monitoring system utilization. The 2006 system utilization results were 22.5% for HP Utilization, and 5.2% for IP Utilization. Reviewing the number of cold weather actions (CWA) at a particular sendout is another method for monitoring performance. From 2005 to 2006, we reduced CWAs from six to three for a 120-124 MMcf (million cubic feet) sendout. Our third performance evaluation method monitors active leaks per mile of main and total number of active leaks. In 2006, active leaks per mile of main held relatively steady, at 0.23. The number of active leaks increased from 2,535 to 2,660. This is primarily due to PSE's aging gas system infrastructure, and because programs like cast iron replacement have already eliminated the majority of large concentrations of leaks. Finally, our fourth method for evaluating performance monitors third party damage. Third party damage per locate request remained steady from 2005 to 2006.

Gas Performance Summary

	2003	2004	2005	2006 Goal	2006 Actual
Active Leaks per mile of main	0.26	0.22	0.22	0.17	0.23
Active Leaks	2,864	2,493	2,535	1,975	2,660
Cold Weather Actions at 120 to 124MMcf	11	7	6	4	3
Cold Weather Actions at 140 to 144MMcf	38	33	20	N/A	17
Gas System Utilization (HP)	95.1%	93.7%	28.3%*	13.5%*	22.5%*
Gas System Utilization (IP)	N/A	N/A	14.0%*	2.5%	5.2%*
Third Party Damage per locate request	0.80**	1.27%	1.16%	N/A	1.16%

*See Gas System Utilization section of new methodology for 2006. **Percentage is for both gas and electric Third Party Damage statistics.

Gas System Utilization/Cold Weather Action Plan

The gas system performed well during the winter of 2006-2007, with some CWAs and curtailments implemented to reinforce the system in targeted areas. System Utilization factors apply to the High Pressure (HP) and Intermediate Pressure (IP) gas infrastructure and are useful for tracking the performance of system upgrades in relation to annual growth in general. The goal for the HP Utilization Factor was 13.5%, and it was 2.5% for the IP Utilization Factor. These goals were based on completing all jobs that were approved at the start of 2006. The actual utilization numbers for 2006 of 22.5% for HP Utilization and 5.2% for IP Utilization are based on actual projects completed and actual system demand. The variation between our goal and the actual end-of-the-year utilization number can be attributed to non-completion of funded 2006 capacity projects.

The method used in prior years for calculating gas utilization was based on a simple ratio of actual gas demand to calculated system capacity. This provided a metric to indicate the condition of the system from a capacity point of view. A larger number was an indication of an increased chance of service interruptions in cold weather. A disadvantage of this previous metric is that the High Pressure (HP) system and the Intermediated Pressure (IP) system were combined even though the desired value and the required effort to make changes can be quite different. For 2006, we implemented a new method for measuring utilization. Separate utilization numbers are calculated for the HP system and the IP system. An informal AGA survey reveals there is no standard method in the industry for determining utilization for a gas system. In fact, PSE appears to have one of the most analytical methods among AGA survey respondents.

The basic concept for gas system utilization is to calculate the total footage of pipe that is at pressures below design criteria on a design day, and comparing that footage to the total footage.

The HP Utilization factor for the end of 2006 was 22.2%. Ultimately, the long-range plan is to reduce this metric to below the 8% level, which would require a reasonable level of cold weather actions to maintain service to customers. The scheduled projects for 2007 are expected to reduce this factor to 16.5%. Projects currently planned for 2008 are expected, upon completion, to further reduce the HP Utilization factor to 8%.

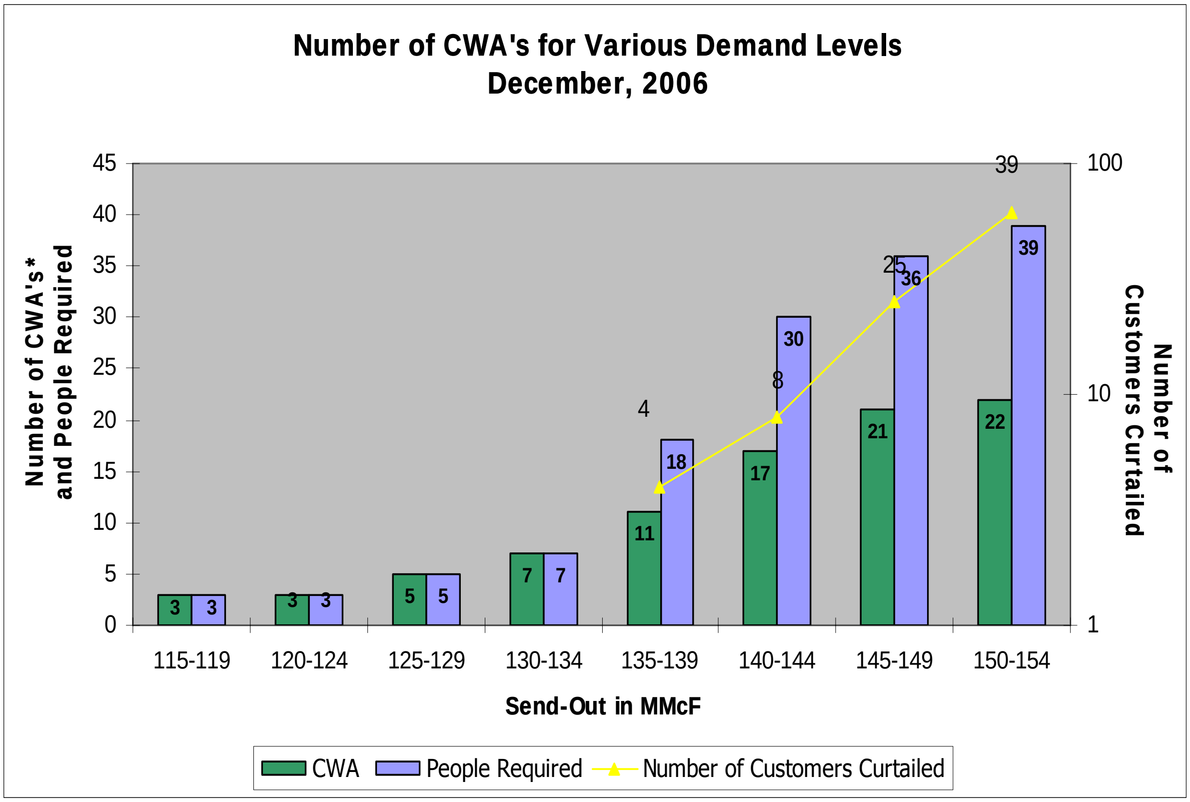
At the end of 2006, the IP Utilization factor was 5.2%. Based on the resources that are available for Cold Weather Actions, an ideal percentage for over-utilized pipe (P<15psig) would be 1.3%. At our current spending level, we anticipate the IP Utilization factor should drop to 1.3% by the end of 2013.

Each year, PSE plans, budgets and completes projects that maximize the probability that natural gas will be available to all firm customers during cold weather at the least cost. By utilizing peak shaving methods such as injecting Compressed Natural Gas (CNG), vaporizing and injecting Liquefied Natural Gas (LNG), bypassing specified regulators, and curtailing interruptible customers, PSE is able to maximize the throughput of natural gas to customers, while minimizing the system investment required for the peak periods.

To do this, PSE continually evaluates our CWA plan as a measurement of maintaining reliable gas service. The CWA plan specifies the actions that should be taken based on the total estimated natural gas sendout between 4:00 a.m. and 8:00 a.m. The sendout estimate is based on many factors including the weather forecast (temperature, wind and snow conditions), the day of the week, and recent system demand.

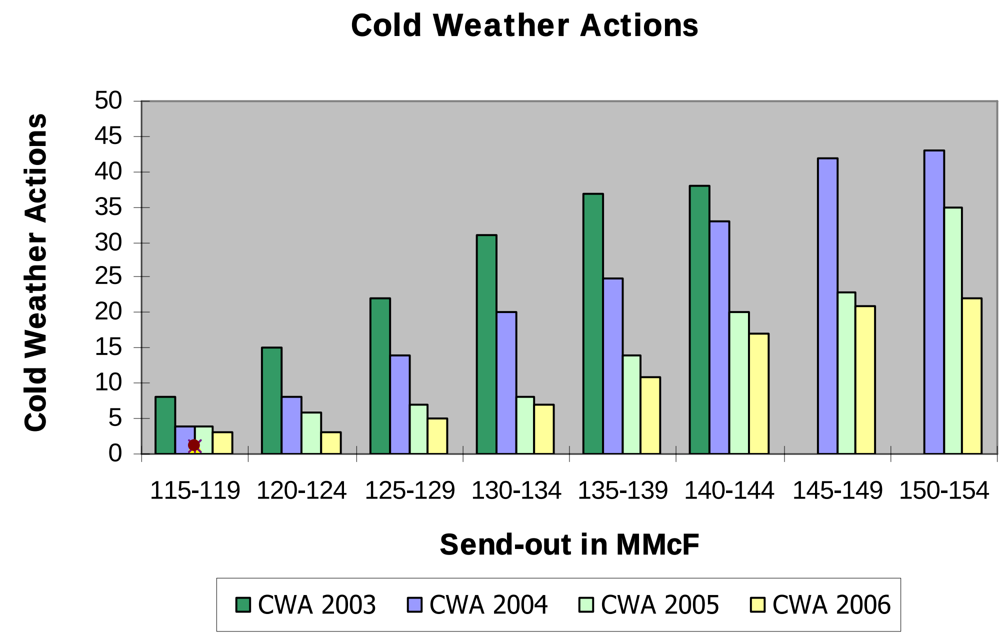
Our 2003, goal was to reduce the number of CWAs from eight to five, for a demand of 115-119 MMcf. We considered this a typical cold weather event, as this sendout was experienced frequently during the winter. However, as loads continue to grow, a higher sendout would be expected for similar temperatures. Therefore, since 2004 a sendout of 120-124 MMcF was projected to be a typical cold weather event experienced frequently during the winter. The target for 2006 was to have six CWAs at a sendout of 120-124 MMcf. In December 2006, there were three CWAs at a demand of 120-124 MMcf. The quantity of CWAs can rise and fall based on the level of curtailments. The number of CWAs required can be reduced if customer curtailments are increased. Based on economic impacts and customer satisfaction, we decided in 2005 to reduce customer curtailments, and slightly increase CWAs. This can make it difficult to accurately compare the CWA quantities impact with previous years, or even previous events, unless the whole picture is assessed. To understand this "whole picture," additional metrics are necessary, which will be well represented by our new utilization calculations.

Completion of system improvement projects can reduce the quantity of CWAs. At higher demands the system is more stressed and the number of CWAs required to maintain service to customers is greater. The following chart illustrates the increase in the number of CWAs, and the personnel required to implement the plan for each demand level according to our December 2006 plan. During the 2006-2007 winter, the number of sites requiring CWAs at 140-144MMcf was more than five times that required at 120-124MMcf.



*Does not include Gig Harbor LNG Facility

This graph displays the history of Cold Weather Actions for 2003 through 2006, and illustrates how the number of CWAs for any given sendout has dropped.



Recent weather that tested PSE's gas infrastructure occurred at the end of November 2006, and in January 2007. The four hour demand on January 12, 2007 of 145 MMcf is an historical high. The combination of high growth in natural gas customers, and numerous relatively cold events in the 2006-2007 winter allowed a good test of the system. The system performed well and predictably at these levels. This can be verified by the fact that the CWA and curtailment lists saw very little significant change from the start of the cold weather season to finish.

There was a significant reduction in curtailments in the 2006-2007 winter in comparison to the 2005-2006 winter. The number of curtailments through a 144 MMcf sendout dropped from 62 for the 2005-2006 winter, down to eight for the winter of 2006-2007. Full curtailment was required for a sendout of 150 MMcf in 2005-2006, but was not required until a sendout of 160 MMcF in 2006-2007.

For 2007, PSE's system improvement projects are expected to maintain the number of overall CWAs. As large system projects are completed in the next few years and PSE approaches our goal system HP and IP Utilization goals, CWAs should begin to stabilize at an economically justified level.

The CWA plan is designed using a complex system model that is continually updated. It is then either maintained or modified after viewing actual system performance on cold days. It is important to know the limitations of the model, and understand what makes it different from the existing system.

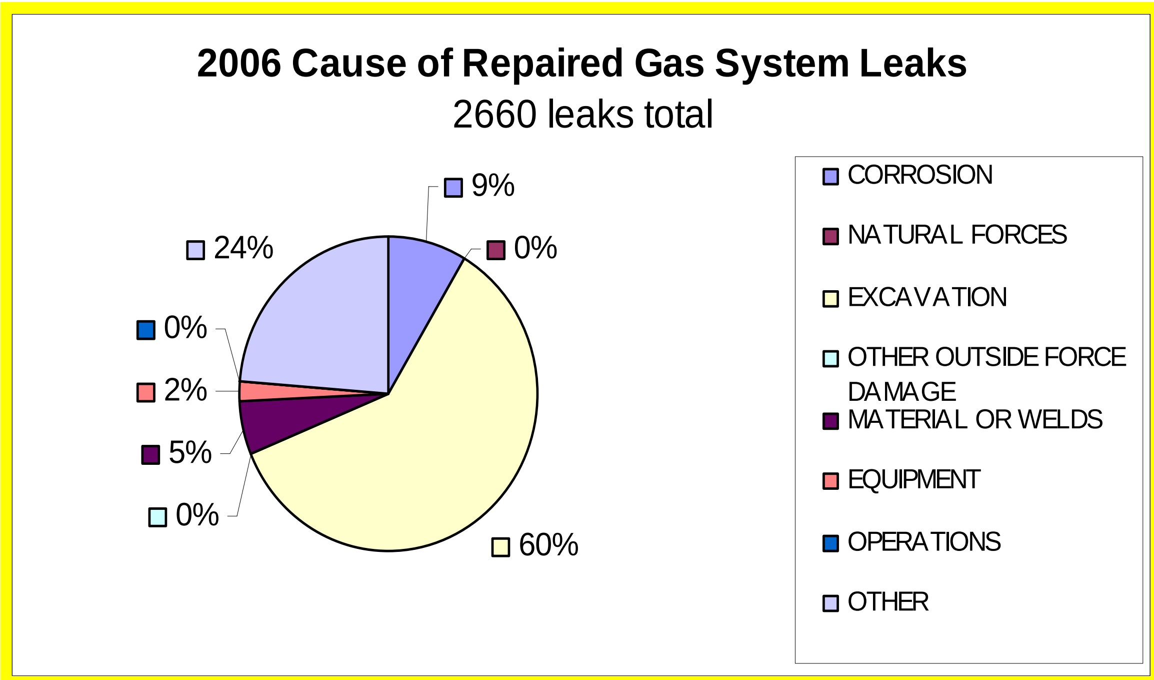
There are several factors that will influence the accuracy of this model's predictions, including:

- *Model Assumptions* **-** Data that is utilized in the model including customer loads, pipe efficiency and friction factors, are based on extensive analysis and experience; however, these assumptions are not exact and customers can, and do, change usage patterns at any time.
- *Model Accuracy* - Planning continually works to ensure the engineering tool used to model the system is as accurate as possible. However, model discrepancies such as incorrect pipe size, pipe diameter, and pipe length are occasionally identified after a high flow period such as those experienced in January 2007. In addition, new customers and new pipe must be manually added to the model, resulting in a lag time between load addition and model updating. To account for this, new customer loads are temporarily assigned to an approximate geographic location until the model can be updated with actual customer loads and as-builts.
- *Field Conditions* – Unknown field conditions, such as partially closed valves and incomplete taps, can cause significant pressure loss that cannot be modeled. In addition, when the demand for natural gas increases, gas velocity also increases. The high velocity can result in debris, inadvertently left inside the main during construction, moving to a valve or other restriction in the system causing a restriction that did not previously exist. These variables cannot be modeled or anticipated.

Due to these factors, the CWA Plan is continually modified throughout the winter based on actual system performance. Because these modifications can result in both additional or fewer CWAs or curtailments, PSE continues to focus on improving utilization and therefore reducing known cold weather actions to ensure resources are available if new performance problem areas are identified throughout the winter.

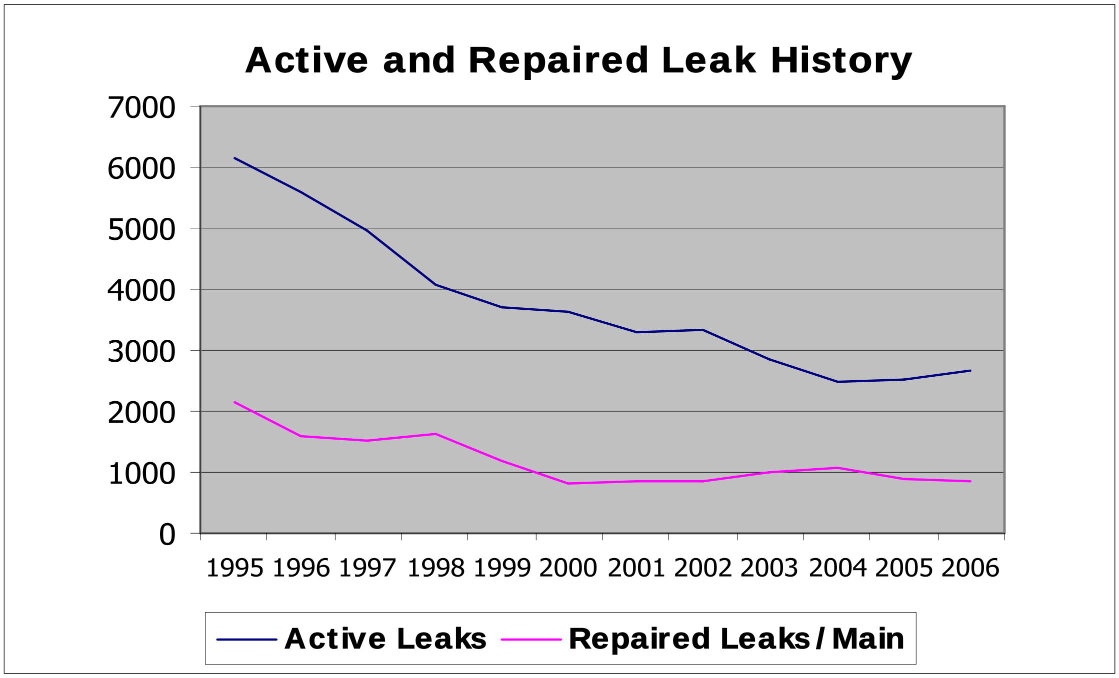
Leakage Reduction Program

The following graph identifies the major causes of gas system leaks requiring repair in 2006. Leak reduction programs are in place to further reduce leaks and the subsequent repair of them. Those programs are discussed in detail below.



PSE proactively evaluates its active and repaired leak history trends, which is important to ensure that the bare steel and cast iron programs are achieving an appropriate balance of leak repair versus system replacement. A trend where active leaks steadily decreased and repaired leaks steadily increased would typically indicate that too many leaks were repaired by addressing the individual leak rather than proactively replacing leak prone areas.

The chart on the next page illustrates the history in active leaks verses repaired leaks and mains for the past ten years.

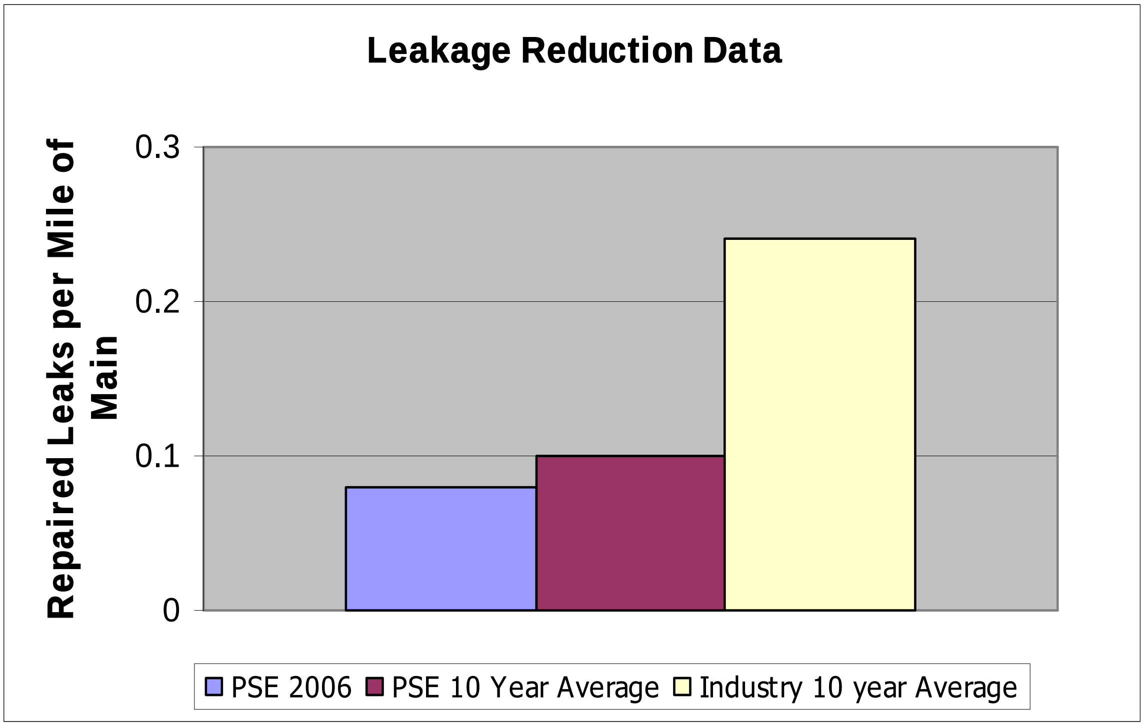


Since 1996, we've reduced active leaks by nearly 60%. Active leakage increased slightly in 2005 from 2004, due in part because PSE's system continues to age and because programs like cast iron replacement have already eliminated the majority of large leak concentrations. There were 2,660 active leaks at the end of 2006. In 2007, 3,449 active leaks will be targeted for repair or replacement to meet the 2,785 internal goal.

Leak repairs are used to benchmark PSE's performance against others in the industry by utilizing reports filed with the U.S. Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA). These reports show that PSE has fewer leak repairs than the industry average. PSE's 10-year average for leak repairs on mains is 54% lower than the industry 10-year average, as shown in the following graph. This, coupled with a long term declining active leakage trend, indicates PSE's leakage management program is successfully reducing leakage.

There are several maintenance activities that monitor leakage in the Leak Survey and Leakage Action programs. Leak Survey is a leak control program that surveys all mains and services by testing of the atmosphere for discovering gas leaks. Surveys also take place for approximately 12,000 indoor meters on the gas system. Other leak inspections are conducted for reasons related to increasing the pressure (uprates), natural events including earthquakes and slides or areas of unstable soils, and when deemed prudent to confirm safe operation. In 2006, 319,636 services and 30,346,562 feet of main were surveyed.

Leakage Action is a program that ensures all active leaks are monitored, tracked, and remediated as required. Leaks are rated and repairs are scheduled within the allowed timeframe for each rating. By the end of 2006, we had made 3,583 leak repairs, and there were 2,660 leaks. If we were to stop leak repair in 2007, we would run the risk of having 4,292 leaks on the system. However, in 2007 we expect to repair 3,449 leaks in order to meet this year's target of 2,785. The increases are due in large part to the greater frequency of our increased rate of leak surveys begun in 2006.



Leakage reduction is achieved by multiple programs, including Third Party Damage Reduction and Cast Iron and Bare Steel Replacement. Discussion of these programs follows.

Third Party Damage Prevention Program

PSE continues to support the reduction of third party damages through our Damage Prevention and Public Awareness Programs. We proactively work with public officials, contractors, and homeowners in an effort to raise the level of awareness with regard to RCW 19.122, the call before you dig statute. Bill inserts, direct mailings, on-site safety meetings, training sessions, contractor dinners, home-shows, and memberships in state and local utility coordinating councils, are some of the methods used to accomplish this.

Trends for locates received and total number of damages for the last four years for PSE's gas facilities are shown in the graph below. Locates are surging as a result of the region's active growth and construction. In 2005, PSE's Standards and Compliance department established performance measures to evaluate the effectiveness of the Damage Prevention Program as it pertains to PSE gas facilities. Those measures are as follows:

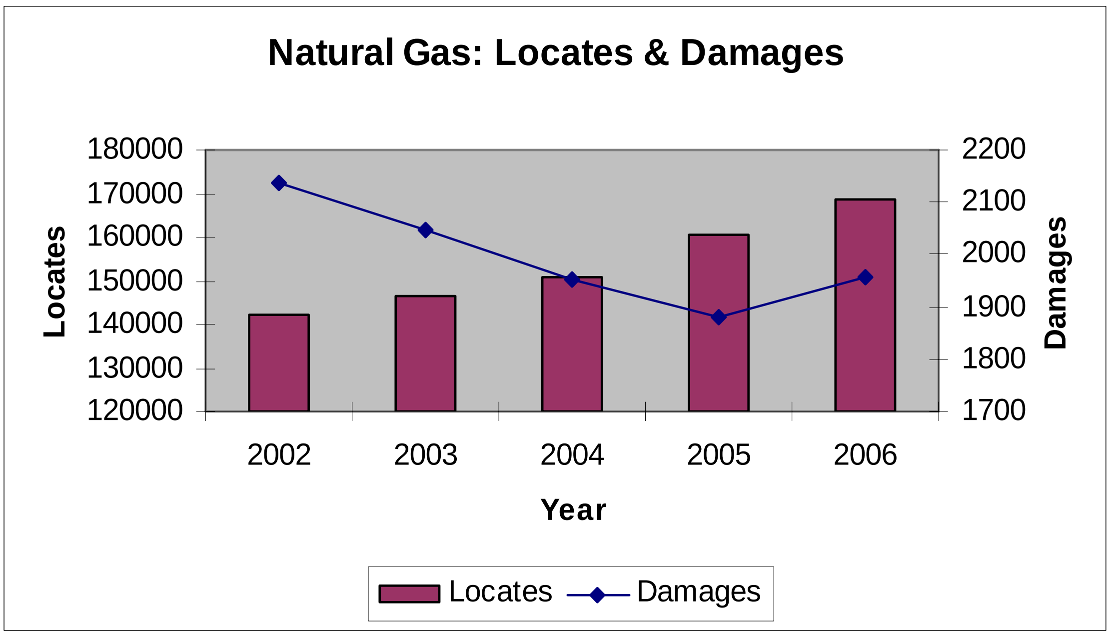
1. Reduction in number of gas damage claims for services versus total number of services
2. Reduction in number of gas damage claims for mains versus total mileage of mains

3. Reduction in number of dig-ins versus number of total locate requests
4. Reduction in "failed to call for locates" versus total number of locate requests
5. Reduction in number of "failed to call for locates" versus total number of dig-ins
6. Reduction in number of excavators with three or more dig-ins

In 2006, 1,955 third party damages were reported. Of these 75 were directly related to a large communication project located in eastern King County.

In accordance with state natural gas pipeline safety regulations, in 2006 PSE submitted a Damage Prevention Statistics Report to the WUTC.

The following excerpt from the report illustrates the trend for locates and the total number of damages over the past four years. As the bar graph shows, the number of locates generally increase as damages decrease.



Pipeline Integrity Management Program

On December 17, 2003, the U.S. DOT adopted the final rule on Pipeline Integrity Management in High Consequence Areas (HCA) for Gas Transmission Pipelines (49 CFR 192). As a result of this regulation, PSE developed an integrity management program to assess and manage the condition of the approximately 30 miles of transmission pipe on our system. PSE has trained field staff to perform External Corrosion Direct Assessments (ECDA), which is the primary method used to assess the condition of our transmission main. This was accomplished by the December 17, 2004 deadline.

Based on risk profile data, PSE pipelines were segmented according to the different risk attributes along the pipeline. Each segment was then scored, and a corrosion assessment scheduled starting with the higher risk segments. A baseline schedule has been established to inspect all 9.5 miles in HCAs over the next seven years. During this schedule, each HCA will be evaluated annually, possibly affecting the inspection schedule.

Of the 9.5 miles of transmission pipelines in HCAs, in 2004 PSE assessed approximately 0.325 miles of the 20 inch South Seattle transmission line, 1.60 miles on the Lynnwood transmission lines in 2005, and 3.1 miles of the North Midway transmission lines in 2006. ECDA was used to determine that the pipelines were in good condition. In 2007, PSE will assess approximately 1.7 miles of the South Seattle and North Midway transmission lines.

We will continue to actively manage the Integrity Management Program. Not only is it subject to periodic reporting to the DOT and regular audits by the WUTC, but continual improvements are also a DOT regulatory requirement. Effective management of the Integrity Management Program will ultimately provide PSE with a systematic pipeline integrity management process that can be clearly demonstrated to any agency or the public.

Additionally, the concepts developed used by the Integrity Management Program are being applied to other areas of the gas system, such as the Wrapped Steel Service Assessment Program and the future development of a Distribution Integrity Management Program.

Cast Iron and Bare Steel Main Replacement Programs

PSE constantly evaluates aging gas systems that are more susceptible to leakage to determine which ones should be replaced to ensure safe and reliable operation of the gas system. PSE has been aggressively replacing cast iron pipe since 1992 under a program designed to replace all cast iron within 15 years, per docket #920487. For the first two years of the program, the number of repaired leaks on mains increased due to the aggressive replacement of cast iron. Since the third year, the repaired leaks per year have declined fairly steadily as the replaced pipe had fewer active leaks. This indicates that PSE was appropriately replacing the pipe with the most leaks first.

Over the course of the cast iron replacement program, PSE's cumulative accomplishments have exceeded the schedule. The WUTC granted permission to spread the remaining footage evenly over the final five years of the program, which resulted in a new reduced yearly target of 80,000 feet per year. In 2003, the target was exceeded by 30,764 feet. As 2004 projects were already in progress, this excess was credited to 2005, making the new target 49,236 feet for 2005. In 2005, PSE replaced 62,539 feet of cast iron, exceeding the target by 13,303 feet. In 2006, PSE replaced 79,275 feet; this is less than the annual target by 725 feet, but still enables us to remain ahead of the revised schedule. By June 2007, to complete the 15-year program, the target is to replace 36,340 feet of pipe. This should eliminate 87 leaks and continue to reduce O&M costs associated with leakage on cast iron.

PSE also evaluates bare steel and wrought iron main that is not cathodically protected to determine which mains to replace. PSE has developed and implemented a Bare Steel Replacement Program to address the joint needs of PSE and the WUTC to eliminate bare steel and wrought iron pipe from our system, due to issues associated with installing and monitoring cathodic protection on bare steel main and the desire to reduce corrosion leaks. This program requires PSE to systematically locate and replace all bare steel and wrought iron protected pipe by the end of 2014. PSE and the WUTC have agreed upon, per docket #030080 and #030128, a comprehensive risk model to use in determining priorities for non-cathodically protected bare steel and wrought iron replacement. In 2006, the target was 99,205 feet, and 88,624 feet were replaced and 85 leaks were eliminated. Continuing into 2007, the remainder of the 2006 target was completed by February 12. The target replacement footages for 2006 through 2010, is 99,205 feet, and year 2011 through 2014 is 137,485 feet. In 2007, 130 leaks are expected to be eliminated through the program.

Critical Bond Program

In addition to replacing older mains that are more susceptible to leakage, PSE protects newer, wrapped steel gas systems from corrosion to maximize their useful life and minimize the potential for leakage. Protection from corrosion is provided by Cathodic Protection (CP) systems that are divided into two categories: impressed current, and galvanic. In April of 1996, PSE initiated a program, Critical Bond, to ensure all the piping in each CP system was adequately protected. Originally there were 2,701 CP systems. During the critical bond program, additional CP systems have been created to facilitate the critical bond process, and some have been retired. The total scope of the critical bond program, to date, includes review and remediation of 3,299 CP systems, as well as 502 regulator stations. In 2006, PSE completed critical bond on 727 CP systems -- exceeding our target of 420 CP systems. In total, we've completed review and remediation on 3,015 (91%) of CP systems, and 502 (100%) of regulator stations.

The target for 2007 is to review and remediate 284 CP systems, which will complete the program. The remaining CP system work is complicated and has required more time than originally anticipated. The program, originally targeted for completion by the end of 2005, will be complete by the end of 2007. The following table shows the target schedule for CP systems.

Critical Bond Plan

Year	Plan Year	Original Target (# CP Systems)	Future Target (# CP Systems)	Actual Completed (# CP Systems)
1996	Year 1	178	---	166
1997	Year 2	178	---	578
1998	Year 3	392	---	451
1999	Year 4	392	---	327
2000	Year 5	392	---	240
2001	Year 6	392	---	296
2002	Year 7	392	---	356
2003	Year 8	385	---	177
2004	Year 9	---	40	122
2005	Year 10	---	273	93
2006	Year 11	---	420	727
2007	Year 12	---	284	
Total Systems		2,701	3,299	3,533

After completion we then activate a robust CP monitoring program utilizing the test sites installed under the critical bond program. The CP monitoring program includes inspections of CP rectifiers, power supply units, and annual monitoring of the cathodic protection system. Remediation work is carried out where there are known issues related to an insufficient ability to monitor and protect pipelines. Resources are also allocated to maintaining system data in SAP, plat maps and operations maps.

Isolated Facilities Program

As part of a 2004 agreement with the WUTC (docket PG-030080 and PG-030128), PSE agreed to develop the Isolated Facilities Program to identify all electrically isolated steel facilities that require cathodic protection to prevent them from corroding. This includes services, mains, extended utility facilities (EUF), and casings. After these facilities are identified, this program will ensure they are being monitored to verify the ongoing effectiveness of the cathodic protection. If the facilities are not part of the current monitoring program, they will be added to the monitoring program and inspected to verify adequate cathodic protection. Any facilities that do not have adequate cathodic protection will be remediated by adding additional cathodic protection, replacing with PE pipe, or retirement. Additionally, the Program will focus on developing processes that will ensure new and newly isolated facilities are monitored. As part of the agreement, PSE plans to fully implement and complete the Isolated Facilities Program by July of 2009.

By the end of 2006, PSE had completed inspection of 437,583 service risers, and remediated 37 isolated facilities discovered as a result of the inspections. In 2007, PSE expects to complete approximately 350,000 service riser inspections, and implement the processes for identifying and inspecting the stubs, mains, EUFs and casings.

Unmaintainable District Regulators

This program helps ensure the remediation of pressure regulating stations when the scheduled maintenance requirements cannot be performed due to location or configuration, or the maintenance has become more difficult and costly. A pressure regulator ensures that downstream customers are protected from excessive gas pressures that could potentially lead to equipment failure or leaks. Approximately 300 regulators have been identified as potentially having one or more of maintenance issues. A five-year plan has been adopted to mitigate these issues starting with the higher risk ones. Since the program started in 2004, a total of 181 stations have been remediated or retired. These regulators were chosen due to the number and level of concerns identified. In 2006, PSE targeted 86 regulators for remediation, including 26 carry over stations from 2005. A total of 60 stations were remediated by year end 2006. In 2007, 68 regulators are targeted for remediation. The program is scheduled for completion by the end of the year 2008.

Pressure Regulating Station and Pressure Device Inspection and Testing – These maintenance activities include annual inspection and testing of pressure regulating station and pressure relief devices including examination for atmospheric corrosion and inspection of farm taps. This includes regulator relief vent remediation. Approximately 740 regulating stations were inspected in 2006, and in 2007 approximately 746 stations will be inspected.

District regulators or pressure regulating stations and pressure relief devices are inspected and tested periodically to ensure they are mechanically in good condition, adequate in terms of capacity, and set to control and/or relieve at the correct pressures. It is through these inspections that maintenance issues surface for evaluation for remediation.

Gas System Maintenance Programs

PSE relies on many different routine activities such as calibrations, patrols, and inspections to assess the performance of components of the natural gas delivery system. This process identifies conditions that require corrective action, such as equipment repair or replacement. Items requiring corrective action may also be identified by the general public or by personnel who come in contact with the natural gas facilities (such as during bridge inspections). When a maintenance issue is identified, it is either addressed through an immediate corrective action, or evaluated per internal procedures to determine the most appropriate follow-up action. As discussed in the following paragraphs, this method for addressing maintenance issues is common across most of PSE's programs that are designed to find and address maintenance concerns.

PSE's gas system maintenance is heavily influenced by code compliance and interpretation of regulations. This means direction -- as determined by PSE's Standards and Compliance department -- has a strong influence on work execution requirements. The Standards and Compliance team anticipates new regulations so that adjustments to budgets can be recommended in order to proactively accommodate additional work that may be required when new regulations come into force.

In 2005, gas maintenance was carried out as a centralized planned activity that aimed to maximize cost benefits while meeting all compliance requirements. This maintenance planning process provided a list of over 108 individual gas maintenance activities, which are summarized in 10 categories below.

Valve Maintenance and Inspection – The maintenance and inspection of valves is comprised of several activities for service valves at locations of high occupancy structures, critical distribution valves, and transmission line valves. The number of inspections and maintenance activities varies from year to year, depending on when inspections are due, the results of those inspections, and valve installations/retirements. In 2006, we completed approximately 6,700 valve inspections, and there were roughly 1,800 maintenance activities related to valves. For 2007 we anticipate approximately 6,600 inspections and 2,000 maintenance activities.

Continual Surveillance - In April 2005, the Continuing Surveillance Program was implemented as a visual surveillance of PSE's natural gas facilities during normal construction, operations, and maintenance work. The program asks PSE employees and our contractors to identify potential concerns on PSE's pipeline facilities. Also as a part of the program, various maintenance records are reviewed to identify possible trends that would be of concern. These conditions are broadly classified as non-standard, unsatisfactory, or unsafe, and each has a different timeline under which it must be addressed. In 2006, this program remediated 25 conditions ranging from nonstandard meter location to concrete cap installation to protect a high pressure pipeline, to the replacement of a section of high density plastic pipe. Through the Continuing Surveillance Program we expect to remediate 50 to 75 nonstandard and unsatisfactory conditions in 2007.

Mobile Home Community (MHC) Encroachment Surveys – Over time, mobile home structures have changed in size and a number of mobile home communities have reconfigured their lots. As a result, mobile homes are encroaching on buried natural gas lines. This program is a multi-year maintenance program to assess the extent of the problem and to remediate pipeline encroachment issues. In addition, we intend to educate community owners and managers of encroachment issues in order to prevent recurrence. There are approximately 185 MHCs in PSE's operating system; each is patrolled every three years at intervals not to exceed 39 months. The patrol will identify service and main encroachments, along with other possible maintenance concerns. PSE has developed a consistent enforcement policy that makes it unlikely that MHC encroachments will occur in the future. In 2006, we identified and remediated situations in 12 communities. For 2007, we've identified fifteen communities for remediation, in addition to 67 communities identified from patrol/surveillance.

Bridge/Slide Program **-** This program addresses maintenance needs identified through ongoing patrols of pipeline facilities on bridges or near slide areas. For bridges, quarterly patrol reports of 266 sites are reviewed for maintenance needs such as coating failures, missing hangers, and valve issues. These issues are investigated, prioritized, and remediated as necessary. For slides that endanger pipelines, quarterly monitoring reports of 43 sites are reviewed. An assessment is made and an action plan is implemented to ensure the stability of the area or the relocation of the pipeline. Patrols are more frequent during inclement weather. In late 2005, the program was revamped in an effort to focus resources to correct a large number of outstanding maintenance issues impacting these facilities. This has resulted in an increase in the number of projects proposed for remediation and, just as important, additional gas system integrity. In 2006 we remediated five facilities on bridges or in slide areas, and plan to remediate 34 facilities in 2007.

Atmospheric Corrosion at Hard-to Reach Locations **-** This program was created to address atmospheric corrosion on pipeline facilities at locations that are difficult for inspectors to access. Examples include bridge sites that require boom trucks, service piping on rooftops, and meter sets inside buildings. Our program goals include the following: achieve consensus on the definition of "hard-to-reach locations", compile a list of bridge sites requiring boom trucks for inspections, develop a process for identifying hard-to-reach locations, and develop plans for remediation of atmospheric corrosion at these locations. We began defining the program and its goals in 2005, and completed process development, definitions and strategies in 2006. The program was implemented in late 2006, and in 2007 two gas mains on bridges identified as "hard to reach" will have a comprehensive inspection through the use of a boom truck. Additionally in 2007, PSE will start to develop a complete list of "hard to reach" facilities through inspections now geared toward identifying these locations. Maintenance Programs will be working to catalog each of these facilities and, together with System Maintenance Planning, determine the appropriate remediation strategy.

Compressed Natural Gas (CNG) stations and equipment, mobile and satellite LNG facilities - This includes the maintenance and operation of compression equipment, delivery vehicles and storage tanks that are used at both the compression stations and equipment, as well as the mobile liquefied natural gas systems and stations (e.g. Gig Harbor). Proper equipment maintenance ensures that equipment used in the CWA plan is reliable, and that customer service reliability is maintained on systems that are over utilized. We maintained two facilities in 2006, and plan to maintain another two this year.

Fixed Factor Measurement - This involves the measurement of gas at a controlled elevated pressure by applying a pressure-correcting factor to the measured volume. This helps ensure correct measurement of gas pressure, which also ensures accurate customer billing. There are approximately 4,560 meters that require this annual check. In 2006, 4,560 fixed factor pressure checks were performed, and we expect to perform an additional 4,554 this year.

Instrumentation/Test Gauge Maintenance - These activities include calibration, replacement and repair work. The program also includes calibration of the Gas Control department's tools used to check pressure, volume and temperature of field instrumentation. There are 876 instruments that require calibrations, which will result in approximately 1,730 scheduled calibrations in 2007 (PV/PVT gauges, ECATS, Suburban gauges, and RTU's). In 2006, we completed 100% of the planned maintenance for 836 RTU, 382 suburban gauge and 558 permanent ID calibrations.

Wrapped Steel Service Assessment Program (WSSAP) **-** As part of an agreement with the WUTC, PSE has implemented a program that assesses the condition of all wrapped steel services in our distribution system installed prior to 1972. The approach for assessing the condition of our wrapped steel services aligns with the integrity management plan developed for our transmission pipelines in 2003 and 2004.

In 2005, we began developing the WSSAP, which outlines the strategy PSE will use to comply with our settlement agreement with the WUTC. We completed development in 2006, which included a full inventory of each of the services covered under the scope of the program, development of remediation priorities and strategies, and development of a model to assess the level of risk attributed to each service. In 2007, 516 services will be replaced under the WSSAP. All have the highest risk. Additionally in 2007, PSE will survey approximately 23,100 services for leaks, and conduct electrical surveys on 200 services to gather additional data on those that pose a lower risk. By the end of 2010, we expect to replace approximately 9,000 services, conduct 92,400 leak surveys, and conduct 1,000 electrical surveys under the WSSAP. As of March 2007, the expected completion date for the WSSAP is December 31, 2010.

III. Electric Performance

Overview

PSE manages capital improvement and maintenance programs with the objective of providing efficient, reliable and safe delivery of electricity. Performance of the electric system can be evaluated through a number of measurements and indices.

Efficiency can be partially evaluated by monitoring system utilization, which is the ratio of electric system peak load to substation transformer nameplate capacity. While system utilization is a company wide average, it is also useful for tracking how well capital upgrades are tracking with growth, and predicting where a new project is needed to maintain reliable service as the growth develops.

PSE also uses standard industry indices to help identify areas needing improvement and to monitor the effectiveness of capital improvements and maintenance programs. PSE reports annually to the WUTC non-storm outage duration (SAIDI) and non-storm outage frequency (SAIFI) based on customer outage minutes from January to December. These metrics have traditionally been calculated excluding major storms which are defined as weather events that interrupt service to more than 5% of PSE customers. The electric system continues to perform well, with metrics that are below the Service Quality Indices (SQI). The table below shows the history of these metrics.

This table features the Electric Performance Summary from 2002 through 2006.

Electric Performance Summary
(Annual Data Jan. 1st to Dec 31st)

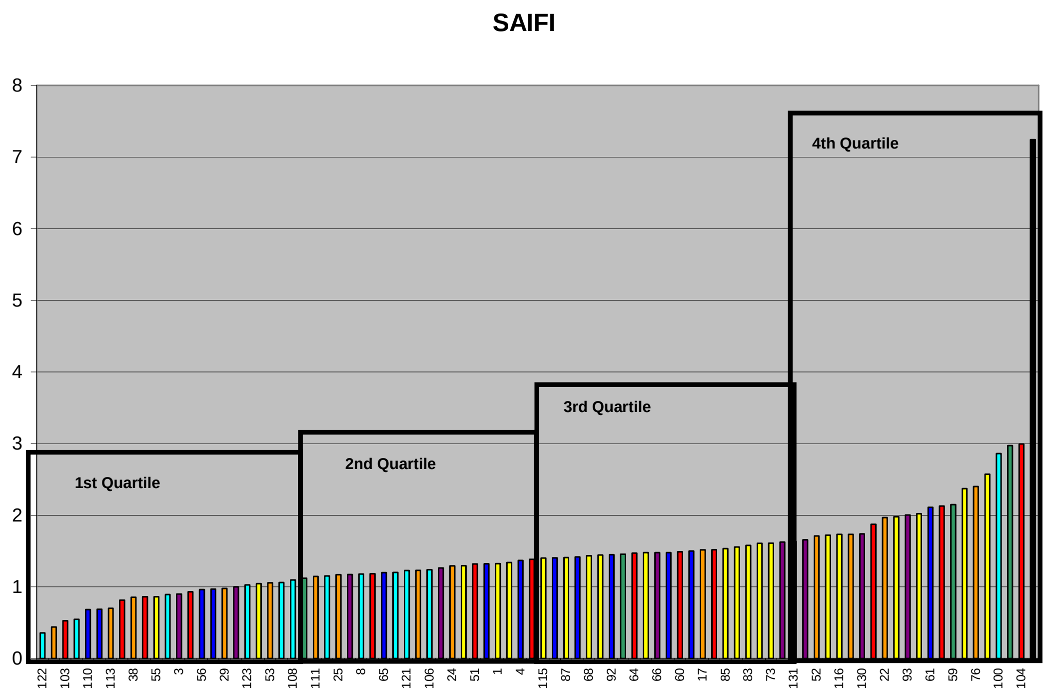
	2002	2003	2004	2005	2006	SQI
Non-Storm Outage Duration – SAIDI*	105.90	133.40	112.80	128.65	214.70	
IEEE Non-Storm Outage Duration - SAIDI**	99.60	106.70	113.80	128.50	162.97	
Non-Storm Outage Frequency – SAIFI*	0.83	0.80	0.77	0.94	1.23	
IEEE Non-Storm Outage Frequency – SAIFI**	0.80	0.71	0.77	0.93	1.033	
Electric System Utilization	85.5%	84.9%	85.6%	85.5%	86.4%	
Third Party Damage	1.02***	0.8***	0.489%	0.437%	0.551%	

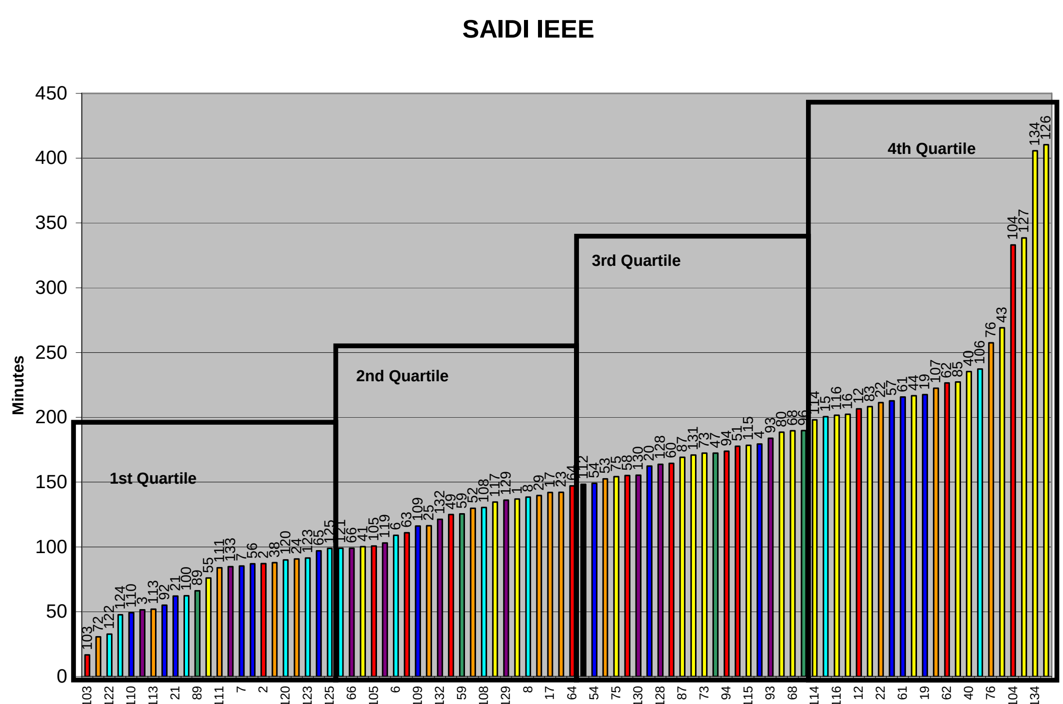
*Indices exclude major events where 5% or more customers are out of service.

**Indices exclude major events where daily SAIDI exceed major event threshold as defined by IEEE 1366.

***Percentage is for both gas & electric Third Party Damage statistics.

Following are the results of the 2006 IEEE survey relating to SAIDI and SAIFI reliability metrics, and the comparison of these with other utilities. For 2006, PSE is in the top XX% for SAIFI, an improvement from 16% in 2005, and the top XX% for SAIDI -- an improvement from 39% in 2005.





Electric System Utilization

PSE monitors electric system utilization to ensure that capital expenditures are allocated efficiently, while avoiding excessive risk. Low utilization levels or excess capacity would be an indication that capital investments are being made too soon, which increases costs. Conversely, excessively high utilization increases the risk of overloading equipment and decreasing reliability. The company-wide electric utilization is based on two variables: (1) the nameplate capacity of the distribution substation transformers company wide; and (2) the winter system peak loading normalized to 23 degrees Fahrenheit. The electric utilization is determined by dividing the peak loading by the nameplate capacity. At the end of 2006, the electric system utilization was 86.4%, just shy of the 2006 internal goal of 86%. The goal for 2007 is 84.3%, with the projects budgeted.

PSE seeks to ensure that distribution substations have the backup capacity to transfer customer loads to adjacent stations in the event of an unplanned outage or planned maintenance. Utilization benchmarks should be established.

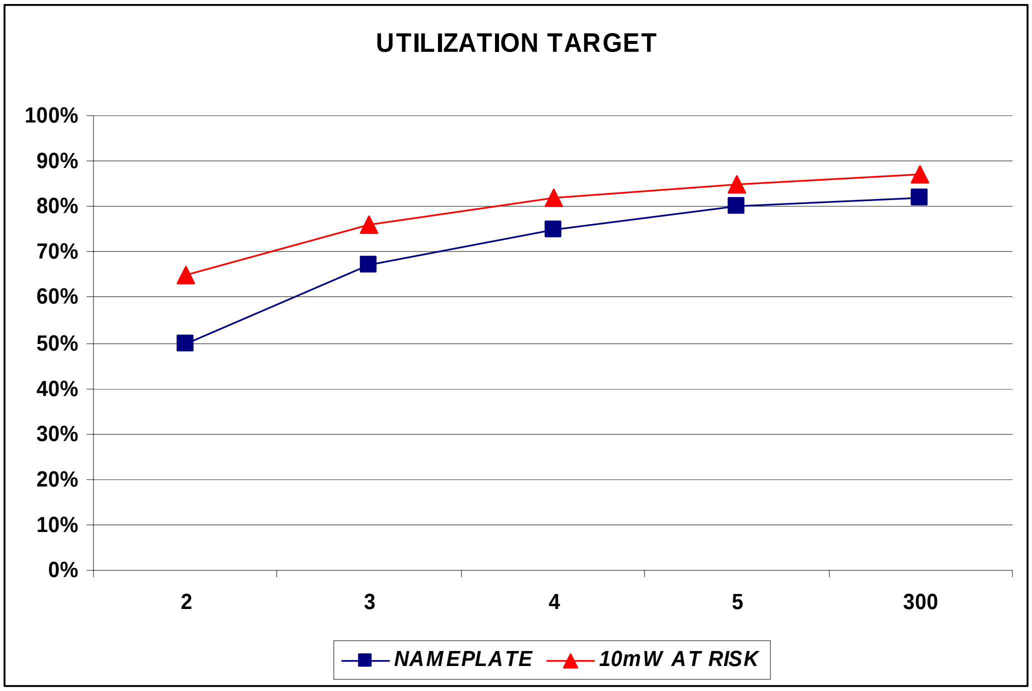
In the past, the overall system utilization target was 85%. Because utilization is a system wide average, when the system is at 85%, there will be local areas that are lower or higher than 85%. For the areas at high utilization, PSE's planning guidelines allow equipment to overload where the load at risk is at a level that can be brought back into service using a mobile substation. New substations are planned when this load is too great and exceeds the allowable overload. PSE has employed this planning philosophy for several years, while maintaining a system wide utilization factor near 85%. A business case is being developed to review whether PSE should revise this target.

For a typical grouping of five substations, the grouping should not be loaded above 80% of nameplate to insure the adjacent four substations can pick up the load from the one substation out of service. If a mobile substation is used to pick up 10 MW of load, the substations should not be loaded above 85%. While use of a mobile substation avoids some level of substation construction, it should be noted that this presents a SAIDI risk since it could take up to eight hours to restore service via use of the mobile, when it will typically take only two hours to restore service by switching loads to adjacent stations.

Following is a table showing the utilization target for different substation groups with and without the use of the mobile substation. For a grouping of more than 300 substations, the utilization should be limited to 82% without the use of a mobile substation, and to 87% with the use of a mobile substation to pick up 10 MW of load. The 82% and 87% targets are based on the trend from the utilizations from substation groups 5, 4, 3 and 2 shown below.

UTILIZATION TARGET

SUBSTATION GROUP	NAMEPLATE	10MW AT RISK
300+	82%	87%
5	80%	85%
4	75%	82%
3	67%	76%
2	50%	65%



With 2.1% annual growth, our system peak is growing at an annual rate of about 114 MW, which is equivalent to about five new 25 MVA distribution substations per year. Our 2007 plan calls for upgrading or building 13 new substations. This will add 290 MVA to the system, reducing the electric utilization to 84.3% in 2007, from 86.4% in 2006 (when we constructed Serwold and Knoble Substations, and upgraded Lochleven Substation).

Electric Reliability

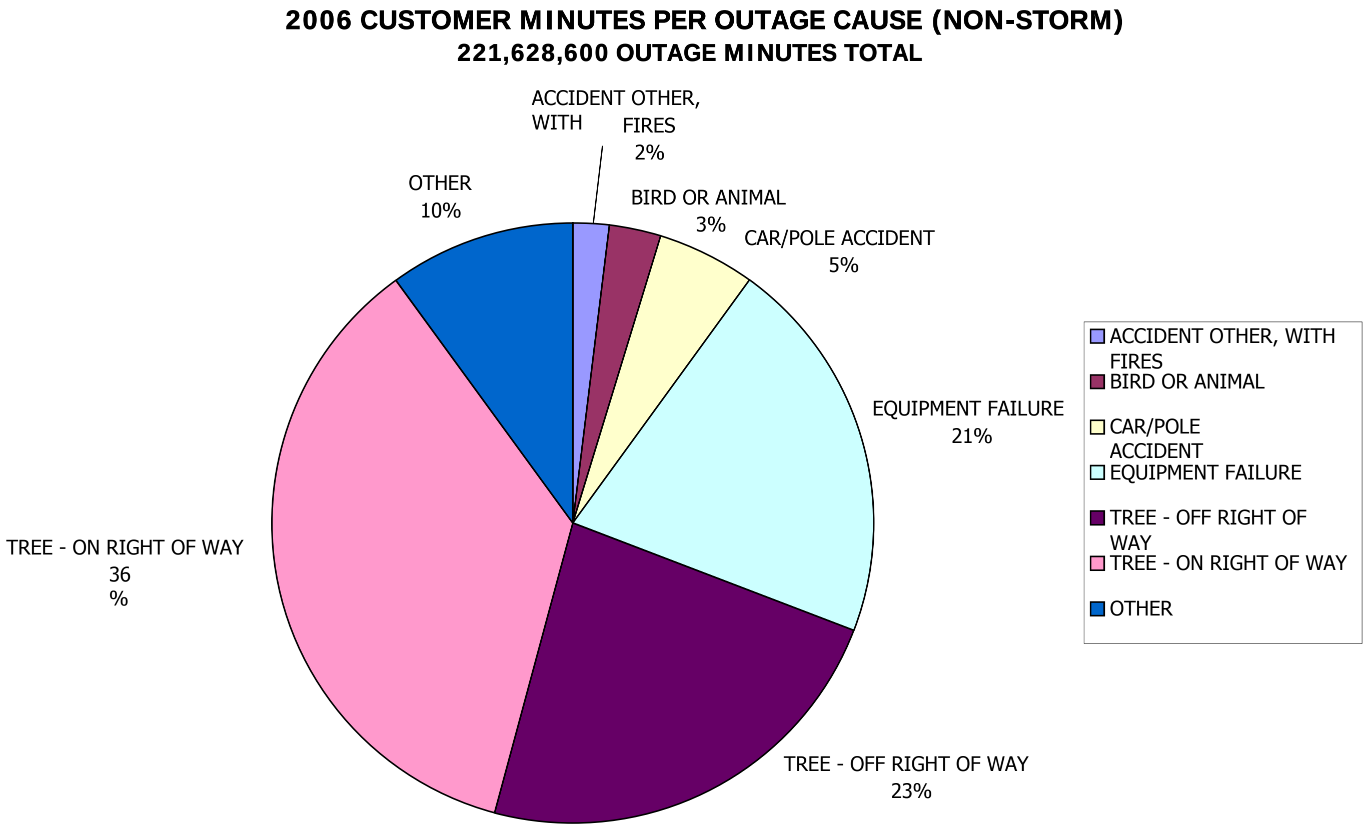
Reliability results based on 2006 statistics as traditionally calculated appear very favorable over a long period of time. When reviewing system performance as measured by annual reliability indices, however, it is important to understand the limitations in determining year-to-year trends. When comparing performance from 2004 to 2005, there was a 13% increase in SAIDI, and a 20.5% increase in SAIFI. The 2005 SAIDI result of 128.65 did not meet the 2005 internal goal of 110, and the 2005 SAIFI result of

0.94 did meet the 2005 internal goal of < 1.0. However, both SAIDI and SAIFI for 2005 were below the SQIs of 136 minutes and 1.3, respectively. This increase is attributed to more outages related to trees on right-of-way, more car/pole incidents, and more scheduled outages in 2005 than occurred in 2004. This variability in SAIDI from year to year may be as much a measure of the severity of weather as it is a measure of the effectiveness of reliability improvements. In an effort to find a method that levels out the random variability of the metrics, PSE also considers the IEEE Standard 1366 method for calculating reliability metrics. IEEE Standard 1366 recommends a statistical method based on a theory of probability and statistics to identify Major Event Days (MED). Also called the Beta Method, its purpose is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be obscured by the large statistical effect of major events, such as local storms.

With major event days removed from the statistics, there is an upward trend for SAIDI since 2002. The increase in SAIDI is due to increased outages from lightning, scheduled outages and tree-caused outages on the right-of-way. Also, some of the increase can be attributed to better data quality achieved through more detailed audits of outage data. Business cases are being developed to help establish SAIDI and SAIFI targets for the next 10 years. The preliminary recommendation is to establish target non-storm SAIDI of 115, and a SAIFI target of 1.0 by 2011, and a SAIDI target of 100 outage minutes per customer and SAIFI target of 0.79 by 2017. This would result in customer satisfaction for outage duration of 95%, and place us in the first quartile of high performing companies.

Another measure for service reliability is PSE's semi-annual Overall Customer Satisfaction Surveys. In 2006, PSE scored ratings between 82% and 86.8% on three questions related to outage frequency, duration, and power quality. All scores have significantly increased over 2004. These ratings continue to show that customers have a favorable perception of PSE's efforts to provide reliable electric service.

Throughout this report, the successes of various programs and maintenance activities are reported in terms of customer minutes saved. While it may be tempting to look for a corresponding improvement in annual SAIDI and SAIFI metrics, it should be noted that many maintenance and capital activities, which are annual and ongoing, are necessary to prevent an escalation of outage minutes. In other words, the maintenance activities in large part just maintain SAIDI and SAIFI at their current levels, and the customer minutes saved are an indication of what the increase in outage indices would be in the absence of the program. The following graph identifies the major causes of electrical system outage minutes that occurred in 2006.



The challenges to provide reliable service can usually be grouped into one of four general categories. PSE targets these general categories using specific programs as described in the table below.

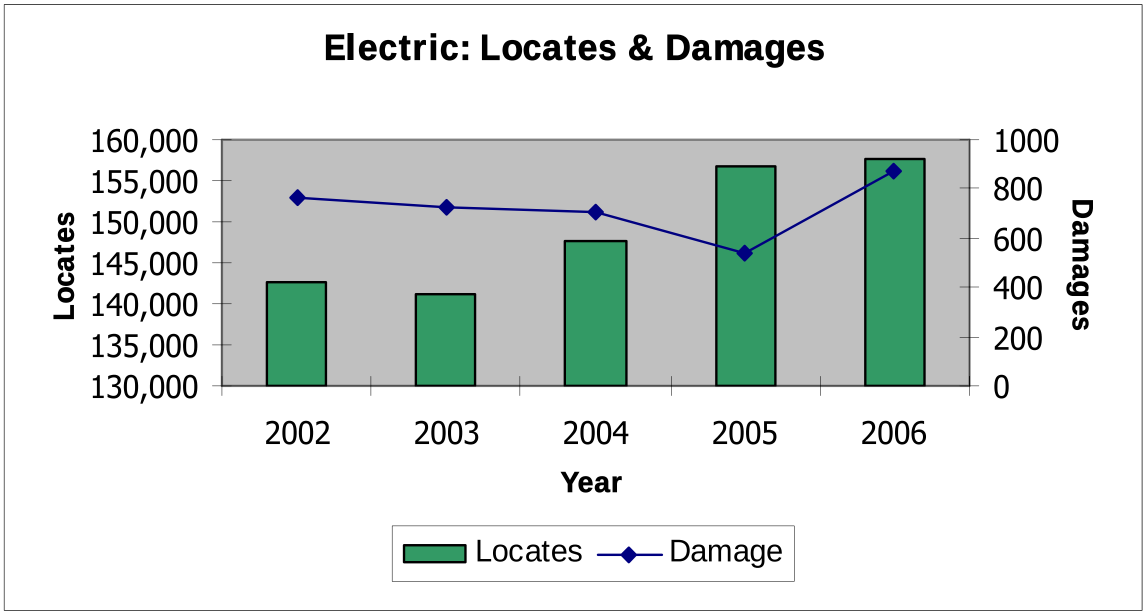
Program Drivers

General Category of Outage	PSE Program
Outages caused by trees	**TreeWatch** **Vegetation Management** **Overhead Outage Reduction**
Outages caused by wildlife	**Animal Mitigation**
Outages caused by the condition of the equipment	**Mark I Switch Replacement** **Cable Remediation** **Substation Maintenance** **Transmission Switch Maintenance** **Pole Replacement** **SCADA** **Transmission & Distribution Maintenance**
Outages caused by the public	**Third Party Damage Reduction**

The following sections detail the programs PSE conducts to manage system reliability.

Third Party Damage Prevention

As with natural gas, PSE is working to reduce third party damage hits on the electric side as well. For the electric system, the amount of Underground (UG) system being installed is creating a more leveled reduction.



TreeWatch Program

On July 8, 1998, the WUTC granted an order authorizing PSE to implement a TreeWatch Program. In the proposed program, PSE had demonstrated that it could realize significant reliability improvements for customers with a focused and targeted off right-of-way tree removal plan. This plan entailed identification of trees whose structural integrity had been compromised, often from disease or recent exposure to greater wind forces via the creation of tree buffer strips or improper logging operations. The program would essentially "harden" the electric delivery system for both routine and significant weather events. The benefits from the program would be realized over 16 years while the program expenditures would occur within the first five (later amended to six) years, and thus a "regulatory asset" was considered a reasonable accounting mechanism for the program. Upon receiving the approved order, the TreeWatch program commenced by significantly increasing the vegetation resources available, communicating the program within PSE's jurisdictions, and initiating communication with owners whose property bordered selected circuits.

The original TreeWatch accounting order expired June 30, 2004. In May 2004, PSE filed for a Petition for an order regarding the continuation of the deferred accounting treatment of its TreeWatch expenditures at a reduced spending level of $2 million per year to focus on transmission and high voltage distribution systems. Because of the benefits derived during the original program, the WUTC authorized us to continue deferring TreeWatch expenditures, at a level of up to $2 million annually, beginning July 1, 2004, to end June 30, 2005.

The deferred program continued until February 28, 2005. At that time, with the general rate case order, the deferred accounting TreeWatch program stopped, and commenced as an operating expense program, at a $2 million annual funding level.

In 2007, the TreeWatch program continues as an O&M program specifically focused on the transmission corridors in order to remove danger trees that threaten transmission and high voltage distribution facilities, as well as distribution circuits with "pockets" of trees which threaten these lines. Since this program is focused on addressing relatively small areas of concern that are distributed over many miles of lines, we plan to measure the impact of this program by focusing on the results achieved, which in this case, is the number of trees removed or trimmed. This will provide an enhanced assessment of the benefits of the TreeWatch Program since it will identify the number of cases in which we removed a threat to our electrical system. In 2007, we plan to remove or trim 18,000 off right-of-way danger trees.

Vegetation Management Program

PSE performs vegetation management on our overhead electric system on a cyclical based systematic approach. The maintenance program focuses on achieving a safe and reliable system. Maintaining proper clearance from energized electric lines is paramount to public safety. Clearances also prevent tree related contact outages from occurring.

Vegetation maintenance is conducted on the overhead distribution system and on the cross-country transmission system utilizing industry accepted pruning standards. Tree trimming occurs on various cycles, depending on the facilities. Tree trimming occurs on the overhead electric distribution system (which includes any portion of the transmission system on the same poles) every four years for lines in urban areas and every six years for lines in rural areas. Danger trees are removed in these right-of-way corridors at the same time. In 2004, the culmination of diligent efforts brought all overhead circuits back on their scheduled cycle. In 2006, vegetation maintenance was performed on 1,628 miles of overhead distribution, which did not meet the 2006 internal goal of 1,872. The amount of work required from storm damage in November and December prevented us from meeting this goal.

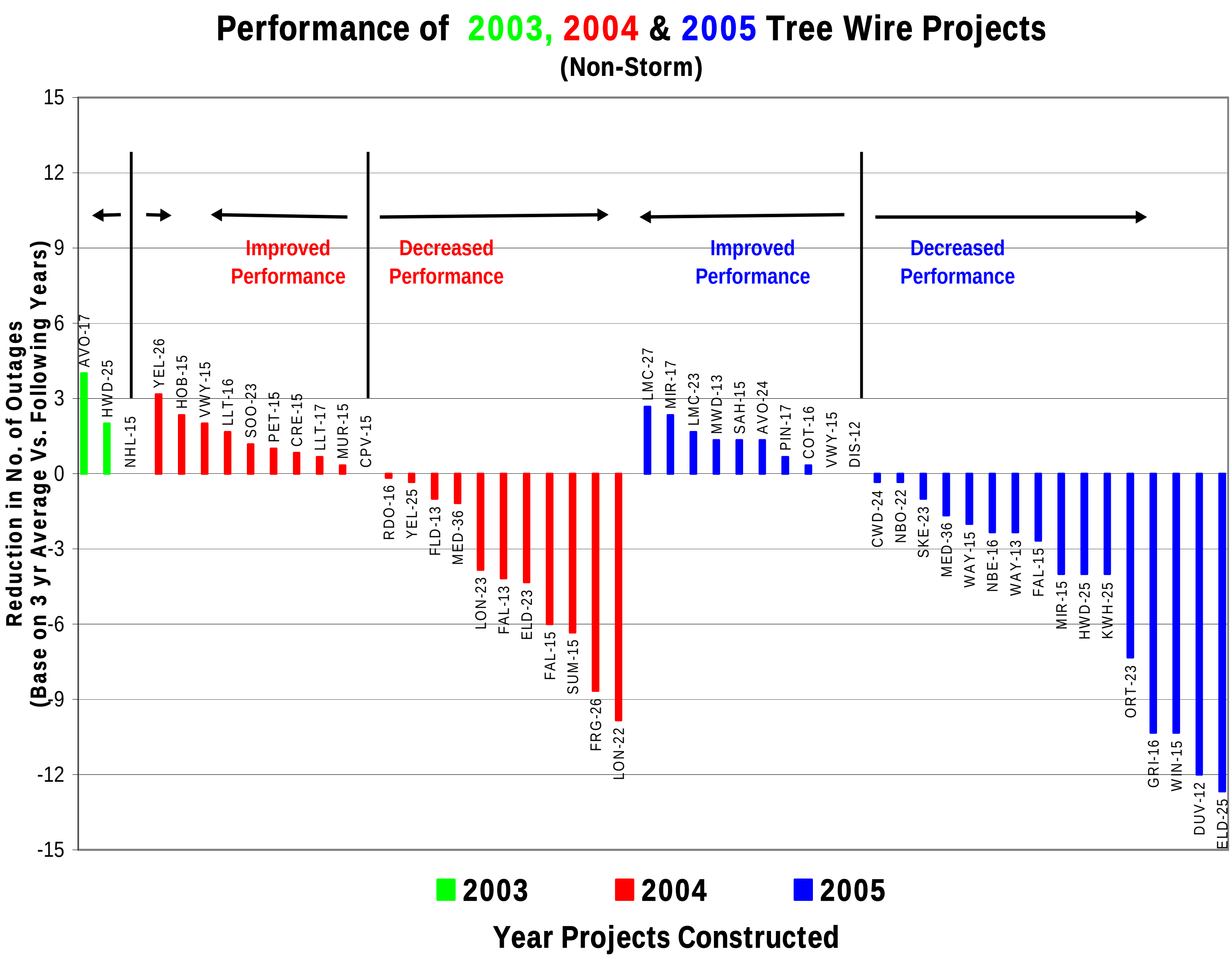
Tree trimming occurs on the high-voltage distribution system and cross-country transmission corridor system every three years. Spray and mowing activities and danger trees removal along the edge of these corridors occur simultaneously. In 2006, we maintained 555 miles of high-voltage distribution and 139 miles of transmission corridors, which exceeded the 2006 internal goal of 509 miles and 127 miles, respectively.

Hot spotting and mid-cycle work and patrols occur yearly on the overhead distribution system, high voltage distribution system, and the cross-country transmission system. This work focuses on fast-growing species that come into contact with the conductors faster than the rest of the circuits. Spraying on the overhead distribution system occurs during mid-cycle as well, focusing again on fast-growing undesirable species. This reduces costs for the next several cycles because the trimming needed, which is the most expensive maintenance activity, is reduced. In 2006, the target was to complete 983 miles of the four-year distribution cycle, 875 miles of the six-year distribution cycle, 563 miles of the three-year high voltage distribution and 139 miles of the three-year transmission cycle. These targets were met.

Overhead Outage Reduction Program

The focus of Overhead Outage Reduction is to provide cost-effective measures to reduce the frequency of outages on the overhead distribution system due to weather. Distribution system planners use three strategies in this program: replace aging #6 copper conductor, install covered conductor (tree wire), and convert overhead lines to underground. Replacing bad order poles and installing animal guards are incorporated in the scope of all these projects as appropriate. This has a secondary benefit of preventing outages caused by wildlife, and preventing equipment failures due to aging plant. Replacing old copper conductor with new ACSR or bare conductor with covered wire reduces the probability of mechanical failure, and reduces the frequency of overhead outages during high wind or winter storms due to tree limb contacts.

The company's outage report database provides the historical outage data to evaluate the performance of the Overhead Outage Reduction Program. Tree-related outage data was collected on 47 different circuits with tree wire construction from 2003-2005. The performances of the tree wire projects were measured by comparing the three-year average of tree related outages before the projects were constructed to the years following construction. The following chart has been broken into three different sections; tree wire projects constructed in 2003, 2004, and 2005.



For tree wire projects constructed in 2003, the base three-year average tree-related outages from 2001-2003 was compared to the following three-year average of tree-related outages from 2004-2006 for those same circuits. The chart illustrates that out of three circuits, two showed an improved performance on average of between two and four outages annually. The third circuit showed no change in performance on average annually.

For tree wire projects constructed in 2004, the base three-year average tree-related outages from 2002-2004 was compared to the following two-year average of tree-related outages from 2005-2006 for those same circuits. The chart shows out of 21 circuits, nine of the circuits showed an improved performance on average of between 0.3 and 3.2 outages annually. One circuit showed no change, and 11 circuits showed a decreased performance on average of between -0.2 and -9.8 outages annually.

For tree wire projects constructed in 2005, the base three-year average tree-related outages from 2003-2005 was compared to the following one-year of tree-related outages in 2006 for those same circuits. The chart shows that out of 26 circuits, eight of the circuits showed an improved performance on average of between 0.3 and 2.7 outages annually. Two circuits showed no change, and 16 circuits showed a decreased performance on average of between –0.3 and –12.7 outages annually.

Of the 47 circuits, 38% showed an improved performance, 8% showed no change, and 54% showed a decrease in performance. The reason for lack of improvements can be attributed to a variety of factors, including the randomness of tree limbs falling into any part of the circuit where tree wire does not exist. Some improvements were made separate from vegetation management activities, and many of the improvements were made on small selected sections of long circuits.

Also, the performance of overhead circuits in this analysis is related to weather events that are not severe enough to be classified as Major Storms. The following chart shows the number of Weather Events from years 2000 through 2006.

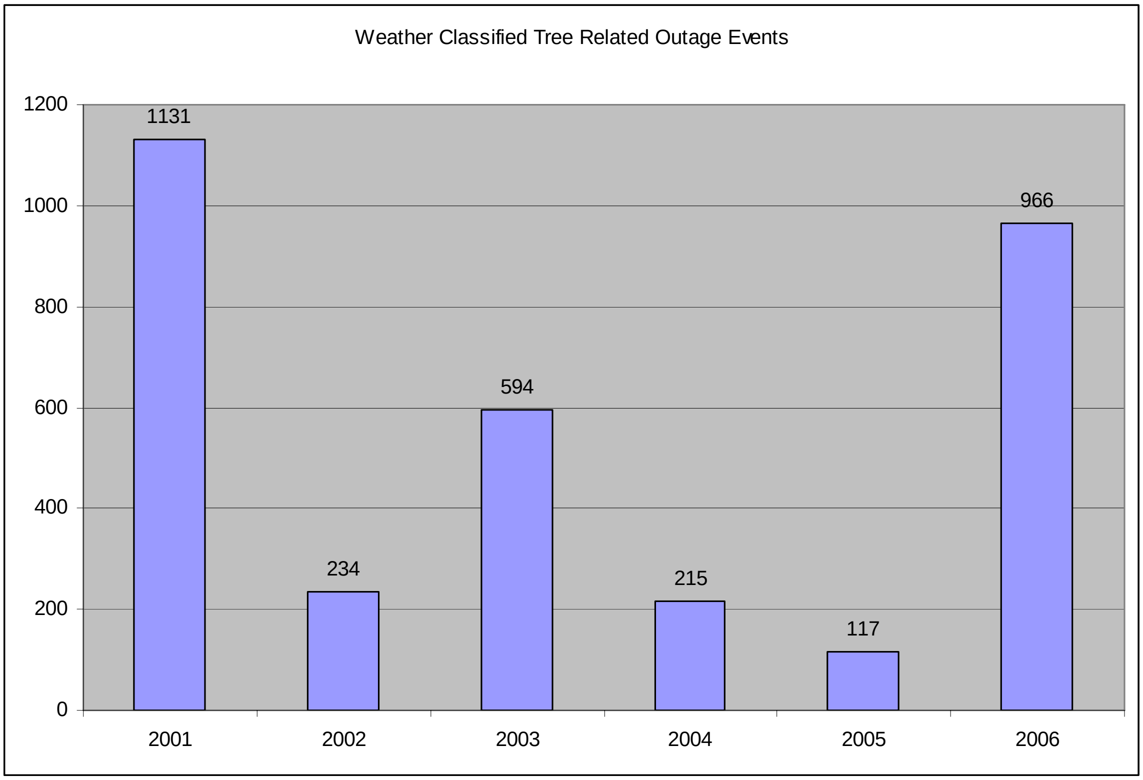
There appears to be a correlation between the performance of the circuits and the number of Weather Events. For example:

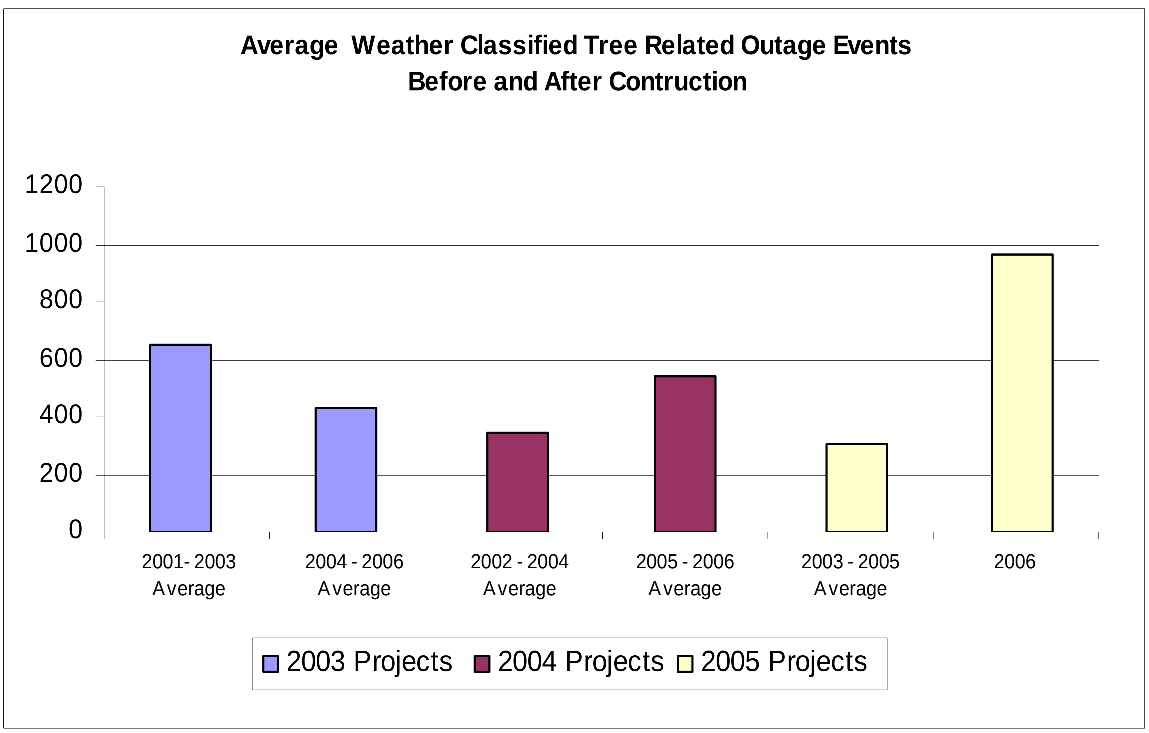
- For 2003 constructed Tree Wire Projects, all three circuits showed improvement or no change and there were fewer Weather Events in the years following these projects. In the three years from 2001 to 2003, there were a total of 1,959 Weather Classified Tree Related Outage Events (average of 653 events per year). This compared to the three years following (from 2004 to 2006) for a total of 1,298 events (average of 433 events per year).

- For 2004 constructed Tree Wire Projects, the total Weather Events in the three years before (2002 to 2005) totaled 1,043 (average of 348 per year) events. In the two years following the 2004 construction, the Weather Events totaled 1,083 (average of 542 per year) events.

- For 2005 constructed Tree Wire Projects, the total Weather Events in the three years before (2003 to 2005) totaled 926 (average of 309 events) events. In the one year following the 2005 construction, there were a total of 966 (average of 966 events) events.

The influence of the number Weather Events in the analysis seems to overshadow the performance of the tree wire projects. This is shown graphically on the following page, where the reader can see the number of "tree events" in the three years before and after various tree wire projects were constructed.


Weather Classified Tree Related Outage Events
1200
1000
800
600
400
200
0
1131
234
594
215
117
966
2001
2002
2003
2004
2005
2006


Average Weather Classified Tree Related Outage Events
Before and After Contruction
1200
1000
800
600
400
200
0
2001- 2003 Average
2004 - 2006 Average
2002 - 2004 Average
2005 - 2006 Average
2003 - 2005 Average
2006
2003 Projects
2004 Projects
2005 Projects

Mark I Switch Replacement Program

In 1998, field personnel identified 298 underground padmount switches for replacement or removal. We developed a standard rating form to evaluate the switch's condition and its priority for replacement. The rating score reflects the following conditions: the worker's escape route, clearance, frequency of operations, condition of barrier boards, cleanliness, cabinet condition, landscape, footing for the worker, and the presence of street traffic.

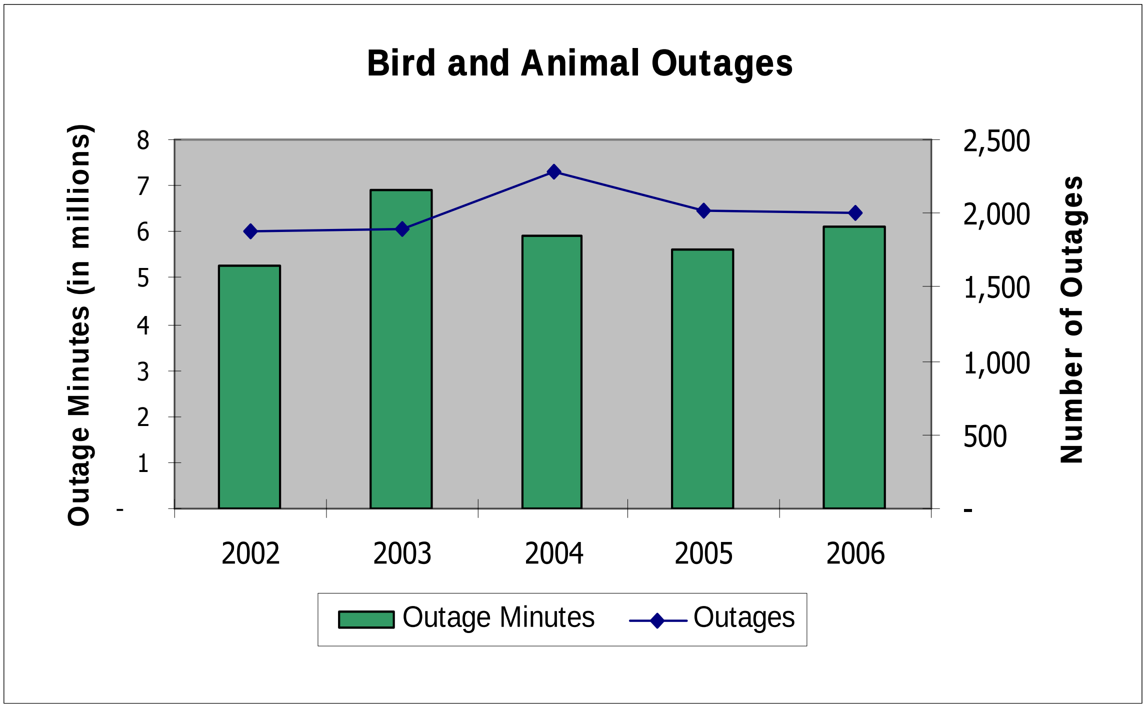
Initially, 298 Mark I switches were evaluated for replacement or removal. Subsequently 14 switches were removed from the list because they were not Mark I switches. During 2005, 20 additional Mark I switches not previously identified were added to the list. As of January 2007, 214 Mark I switches have been replaced, including 10 replaced in 2006 that did not meet the 2006 internal goal of 26. In 2007, 16 switches are planned for replacement or removal, with 74 remaining. At an annual replacement rate of 15 switches, we anticipate all Mark I switches will be replaced by 2012.

Animal Mitigation Program

In 2006, birds and animals were the second leading cause of electrical system outages. Of the 13,845 outages reported, 1,996 were the result of birds or animals contacting energized parts of lines and equipment. In addition, many of the outages (approximately 267), categorized as "unknown" in origin, are thought to be the result of birds and animals that made contact with overhead lines. We assume the animal remains fall into underbrush and go undetected during line patrol, resulting in an outage cause designation of "unknown."

Even though bird and animal outages are a leading cause of electrical outages, they had lower impacts in terms of the total outage duration (2.7% - sixth leading cause), and total customer outages (4.8% - fifth leading cause). This is because these outages generally result in blown fuses on overhead transformers that affect few customers and are quickly restored by servicemen.

About 99% of all animal-caused outages were the result of contact with overhead distribution lines and equipment. The animal typically contacts the bushings on overhead equipment and underground terminal poles. Large raptors such as bald eagles can stretch their wings between phase conductors and cause an outage. About 1% of the outages are caused by contacts with substation apparatus or at pad-mounted underground switchgear. Substation and padmount switch outages, while fewer in number, have higher impacts on SAIDI and SAIFI and are typically more costly to repair.



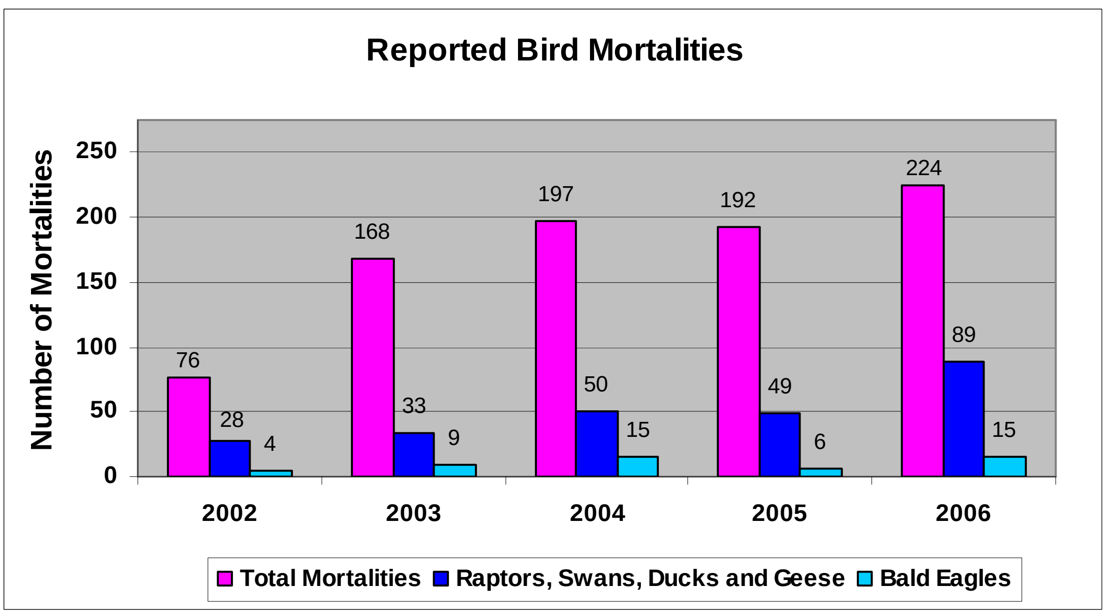
The graph above illustrates the magnitude of animal-caused outages. In an effort to address the issue of animal-caused outages, PSE has established new standards and initiated programs to improve electrical reliability. In 2006, PSE took the following steps to reduce animal caused outages on the electrical system:

- Installed approximately 2,900 bird and animal bushing guards and avian protective devices in target areas with identified wildlife problems. These devices were installed during New Construction and Electrical First Response activities or as part of Avian Protection Program efforts.
- The bushing installation program initiated in 2005, which directed servicemen to install bushing covers on an estimated 1,200 transformers per year where animals or birds caused an outage, was fully implemented in 2006. In 2006 more than 1,500 bushing covers were installed. This program should eliminate repeat outages at the same transformer, reducing the number of animal-caused outages by an estimated 5% to 10% per year.
- Installed bus covers made of insulating material at the Schuett Substation which met the internal 2006 goal. This installation reduced the risk of bird and animal electrocutions and the resultant damage to electrical equipment.
- Installed dead-front PME switchgear at 13 locations to reduce the risk of rodent outages in underground electrical systems.

In 2007, the Burrows Bay and South Kirkland Substations electrical equipment will be protected by installing DC electrical fencing to prevent squirrel access. These fences reduce the risk of animal electrocution and subsequent damage to electrical equipment. It is expected that two outages will be eliminated annually, and more than 1,068,870 customer outage minutes per year will be eliminated as well. New substations are also being constructed in a manner that makes them much less susceptible to animal-caused outages. In addition, we have planned rebuilds on portions of eight distribution circuits, -- Schuett, Birch Bay and Slater in Whatcom County, Wilson and Hickox in Skagit County, Port Ludlow and Irondale in Jefferson County, and Coupeville in Island County -- where eagles or swans have been previously electrocuted or have collided with lines. This is expected to eliminate eight outages annually. PME switchgear will continue to be placed in service, as opportunities present themselves. Establishing internal goals for 2007 is difficult due to the reactive nature of the program.

Avian Protection – PSE maintains an ongoing commitment to investigate avian electrocutions and collisions with company facilities. We're required to monitor and report to the U.S. Fish and Wildlife Service (USFWS) both the locations and number of raptors and migratory birds that are electrocuted or collide with PSE power lines.

The following graph illustrates that incident reporting improved from 2002 to 2006. Reported incidents more than doubled from 76 in 2002 to 168 in 2003. In 2004 and 2005, the number of reported incidents leveled off for the first time. The 2006 increase to 224 birds can be contributed to a 45% increase in swan mortalities, and a 60% increase in eagle mortalities -- most likely associated with improvements in reporting and increased population levels of these high-profile birds in Skagit and Whatcom counties.



In 2005, PSE completed development of an Avian Protection Plan (APP). This serves as a guideline and a reference for PSE employees, contractors and service providers in managing avian power line interactions. This document and the "Raptor Protection" Standards that were developed in 2004 provide guidance and a framework for PSE's continuing commitment to reduce the risk of avian/power line interactions.

The APP includes a strategy that incorporates reactive, proactive and preventative measures to reduce the hazards to migratory birds.

- Reactive: Retrofit (add bird protective devices) or redesign existing lines where migratory bird deaths have occurred. Work is usually completed with O&M dollars.

- Proactive: Evaluate avian electrocution and collision risks of existing lines in high-use avian areas and modify structures where appropriate. Work is usually completed with capital dollars.
- Preventative: Construct all new or rebuilt lines in high-use avian areas to PSE's raptor or avian-safe standards. Work is completed with capital dollars.

In order to reduce the hazards to migratory birds, PSE has capital and O&M budgets dedicated to avian protection. We have completed more than 1,900 reactive and proactive work units since the inception of the avian protection program in 2000. A unit is a span or pole that has been retrofitted or redesigned to reduce the risk of avian mortality to migratory birds. In 2006, 23 reactive projects were completed, protecting approximately 157 reactive units. Twenty-two proactive tree wire projects were completed, protecting approximately 570 proactive units. Proactive units, while more costly are usually done as collaborative projects to increase reliability and strengthen the electrical system. These projects usually employ the use of tree wire and reduce risk to birds both at the poles and between spans, while reducing the risk of tree caused outages as well.

Preventative measures must be employed when new lines are constructed or existing lines are rebuilt in high-use avian habitat. To reduce the risk that protected migratory birds will be harmed, lines are built to avian-safe standards. Creating avian-safe structures usually involves just changing the size of the cross arm or adding relatively inexpensive avian protection covering or guards during the construction process. Preventative work is completed through collaborative efforts with all PSE employees and contractors. In 2006, PSE completed a mapping project to identify high-use avian habitat in our service territory, and installed the "critical avian habitat" information as a layer on PSE Maps. This information on critical avian habitat is now available to planners and engineers at the beginning of the permitting and design process, insuring that Avian-Safe construction is implemented on all new construction projects in high-use areas. The advantages of doing preventative projects up front are that it can be accomplished as part of a larger capital project and can be completed at little or no additional cost. In 2006, approximately 25 preventative (new construction) projects were completed, protecting approximately 250 preventative units. Completion of this work avoids the need to retrofit poles and spans, after the fact, saving over $200,000 O&M dollars in retrofit costs, and assures that PSE is in compliance with federal regulations.

PSE has over 10,000 miles of distribution lines in our service territory. At least 2,500 miles of this line (approximately 50,000 units) creates a risk of avian mortality from electrocution or collision because the lines are located in prime high-use avian habitat, mainly in Skagit, Whatcom, Kittitas and Island Counties. In 2006, approximately 70 Reactive, Proactive and Preventative projects were completed, and these efforts protected approximately 977 units. PSE's goal in 2007 is to continue to build avian safe structures on all new construction projects in high use avian habitat. In coming years, we will utilize various types of data to ensure that we focus our funding on those sections of line where we expect to have the greatest impact in terms of reduced avian mortalities. The USFWS continues to be pleased with the actions that PSE has taken to reduce the hazards to migratory birds associated with PSE electrical facilities.

Cable Remediation Program (CRP)

When the CRP was initiated in 1990, cable systems were remediated via replacement or abandonment. In 1996, PSE began to employ silicone injection to restore the condition of the insulation of the cable, extending the life of the cables for 20 years or more without the disruption of trenching through established neighborhoods. Silicone injection restores cable insulation to "like-new" conditions in aging underground systems and greatly improves reliability to the customers served by those systems. Economics dictates that silicone injection is used in single cable trenches only. Cables are replaced when there are two or more cables in a trench.

Cable systems are selected for the planned CRP budget using a prioritization process. This begins with a review of the outage history, or with a survey of the neutral condition of the cable system. Neighborhoods and commercial areas identified with a degraded neutral, or a high failure rate are submitted for budget approval during the following year. Projects are prioritized by:

- The condition of the neutral.
- The frequency of outages due to cable failures.
- The number of customers affected.
- The average duration of outages experienced by customers.

Open Incident Review (OIR) is a new program element begun in 2004. Under this program, planners review every cable that fails in a looped system and has been switched out of service, leaving the system vulnerable to a longer duration outage. An engineering review is performed for each failed cable to determine what immediate action is to be taken to restore the loop: repair, abandon, inject, or replace. The OIR also addresses cable systems that have a sudden increase in cable failures and will adversely impact system performance between annual budget cycles. The OIR includes the following steps:

- Review of the condition of the cable system neutral.
- A financial analysis of continued O&M repairs and deferred capital remediation costs versus immediate capital remediation costs.
- Review of significant customer impacts due to poor system performance.

The CRP's recent history is summarized in the following table:

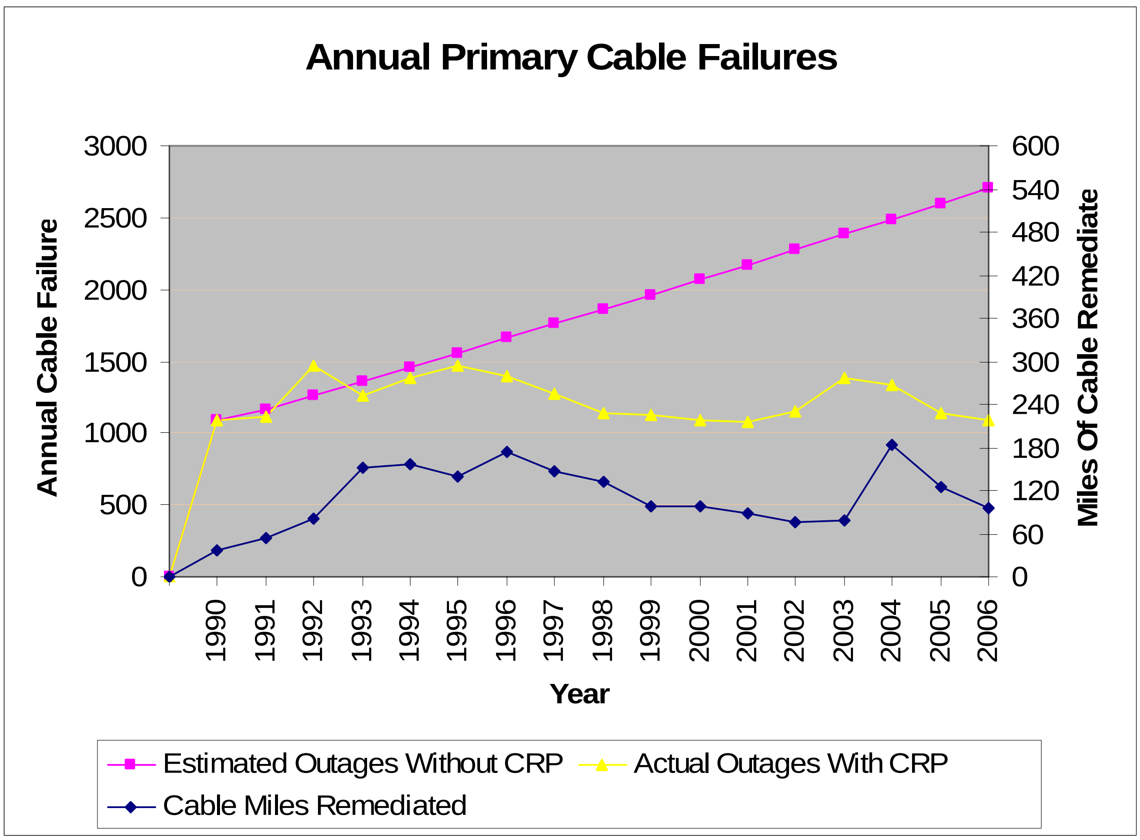
Table III - Cable Mileage Remediated per Year

Year	Miles Injected	Miles Replaced	Miles Abandoned	Total Miles Remediated
2002	61	14	1	76
2003	59	18	1	78
2004	106	62	16	184
2005	77	46	1	124
2006	40	55	1	96

Spending dramatically increased on cable remediation in 2004 and 2005, in response to an increasing trend in cable failures in 2002 and 2003. In 2006, 96 miles of cable were remediated out of 124 miles that were targeted. Targeted to actual miles vary based on the amount of cables that are replaced versus injected. An additional 100 miles of cable are targeted in 2007. In 2007 the annual planned CRP budget to remediate cable systems is funded at $14 million, while the OIR is funded at $4 million. This expenditure should limit the number of failures to approximately 1,100 maximum in 2007.

The following graph shows the estimated annual cable failures that would have occurred without the CRP, compared to the actual failures experienced on the PSE system. Also shown are the miles of cable remediated each year. Like the Overhead Outage Reduction program, it is important to note that the benefit of cable remediation extends beyond the first year following the remediation. Cables tend to fail with increasing frequency with each additional failure. The benefit of outages avoided in the first year following remediation grows by approximately 3.3% per year for the next five years.

The graph on the next page illustrates the annual cable failures and miles of cable remediated since program inception.



2006 marked the 17th year of the CRP, resulting in a total of over 1,917 miles of cable remediated to date, out of the estimated 4,800 miles of cable installed prior to 1981. There were 1,094 failures in 2006, which compares very favorably to the estimated 2,706 outages that would have occurred without the CRP. This equates to an estimated O&M savings of $6.9 million in 2006.

Feeder Cable Replacement Program – In 2005, PSE initiated a program to evaluate and replace feeder cables. Feeder cables comprise approximately 20% of the cable miles in the company, but failures of these cables account for approximately 50% of the total customer outage minutes for cable failures. A study identified vintages of feeder cables between 1965 and 1985 that had a higher-than-average failure rate per 100 miles of cable than other vintages during that period. When cables of the high-failure rate vintages failed in conduit systems, other cables installed on the same work order were scoped for replacement as well. When cables of the high-failure rate vintages failed for the second time in direct-buried systems, the cables were replaced rather than repaired.

In 2006, seven projects were funded that resulted in replacement of five miles of cable at a cost of $962,000. In 2007, feeder cable replacement will be funded using the Unplanned UG Distribution budget that will replace approximately five miles of feeder cable. We estimate the program will result in an annual savings of 1.5 feeder failures and 360,000 customer outage minutes per year.

We're now working to develop a neutral testing program. This program is intended to proactively identify and prioritize replacement of cables with deteriorating neutral wires.

Transmission Switch Program

PSE has approximately 250 transmission line switches installed on wood poles that are used to sectionalize transmission lines either for planned work on the system, or to speed service restoration in the event of an outage. We have designed a maintenance and replacement program to help ensure that the switches function as designed, and to prevent them from failing in service, resulting in electrical outages or delaying system restoration activities.

In 2003 PSE developed a program to upgrade and maintain the existing transmission switches. The program was developed both to address performance issues with a collection of aged switches and in response to two high-profile switch failures in 2002 that resulted in a total of 4,446,333 customer-outage minutes.

In 2006, the program resulted in:

- Replacement of seven switches that were 35 years of age or older. These switches had increased maintenance costs, and spare parts were no longer available.
- Inspection and maintenance of 36 switches. Switches not targeted for replacement will have inspection and maintenance scheduled from 2004 through 2009. Upon completion of this maintenance cycle, the switches will be inspected with an IR camera every two years to monitor their condition for future maintenance.
- Removal of one switch that was no longer required for system operation, and therefore eliminated maintenance costs and reduced outage potentials.

In 2007, 20 switches have been scheduled for maintenance at a cost of $181,000, and five switches are targeted for replacement at a cost of $300,000. Also, approximately 125 of the switches will be inspected with an infrared camera to check for excessive heating at all current-carrying mechanical connections points.

Pole Replacement Program

PSE has approximately 325,000 distribution poles and 32,000 transmission poles, the average age of which is 31 years. When a pole is installed, it is selected based on its ability to support the line while being subjected to wind and ice loads that are listed in the National Electric Safety Code. PSE performs routine pole inspections to assess the condition of the poles, and identify units that are degraded and in need of replacement.

PSE has existing inspection programs for both distribution and transmission wood poles. While our inspection processes vary based on the type of pole, the common goal is to identify poles that have deteriorated, so replacement can be planned. In support of these efforts, pole/crossarm/insulator failure information is tracked and analyzed. This helps to understand how equipment is behaving in the field, and identify developing trends. In 2006, there were 51 outages caused by pole failures, which resulted in 2,425,321 outage minutes.

In 2006, 517 distribution poles and 224 transmission poles were identified from inspection programs and replaced. These replacements were augmented by the unplanned replacement of an additional 1,457 distribution and 37 transmission poles that were identified during storms or day-to-day operations. In 2007, 440 distribution poles and 225 transmission poles are planned for replacement.

PSE is gradually increasing our funding of wood pole inspection and treatment over the next four years so that by 2011 we will be inspecting and treating 10% of our wood poles each year as part of a 10-year cycle. At the end of the first cycle, the pole reject rate is expected to drop from 11% to approximately 2%.

Supervisory Control and Data Acquisition Program

Supervisory Control and Data Acquisition (SCADA) is a system used for monitoring and control of 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. Having SCADA in the substations means 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 up restoration efforts and reduces inefficiencies when it's needed the most.

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.

In 2006, we put 32 SCADA systems into service, resulting in an estimated 27,971,280 customer minutes saved per year. Additionally, construction was completed on a number of other projects, which will be completed in 2007. SCADA at 35 substations is planned to be in service in 2007.

Transmission and Distribution Line Maintenance Programs

PSE's Planned Maintenance programs rely on time-based and/or condition-based inspections to identify components that are in need of maintenance, repair, or replacement (e.g. vegetation management). They have been implemented to manage costs, address safety concerns, and minimize customer outages and the resulting complaints.

Cable Neutral Corrosion Testing - PSE focuses significant resources each year on cable remediation by injecting cables with silicone fluid, which restores the cables' insulation to like new condition. Before cables are injected, the copper neutral wires on the outside of the cables are tested to make sure they have not deteriorated to the point where cable replacement is required. In 2007, PSE will be developing a proactive program to test and identify deteriorated neutrals so that the cables can be replaced on a priority basis.

Transmission Line Inspection **-** PSE transmission lines are a critical asset to maintaining reliable service. After the winter season, selected lines are surveyed for damage. Most lines are surveyed on foot, but in areas where these lines cross country and are difficult to access, PSE uses a helicopter to inspect for damage. Damage is documented using digital photography, and evaluated to determine if immediate or future repairs are warranted. In 2006, 23 structures either had poles replaced or had repairs completed from planned inspections. In 2007, PSE will replace damaged transmission insulators at an O&M cost of $75,000 identified during inspection of the Cascade – White River 230kV line.

Submarine Cable Warning Sign Inspection & Maintenance **–** In order to warn vessels that may drop anchor near cable crossings, we install signs at the shore end of all submarine cables crossing lakes and the Puget Sound to identify the presence of cable. In 2006, eight signs were installed or replaced at a cost of $25,000. In 2007, three signs are targeted for installation, replacement, or maintenance, and permitting will be completed for signs targeted for 2008.

Substation Maintenance Program

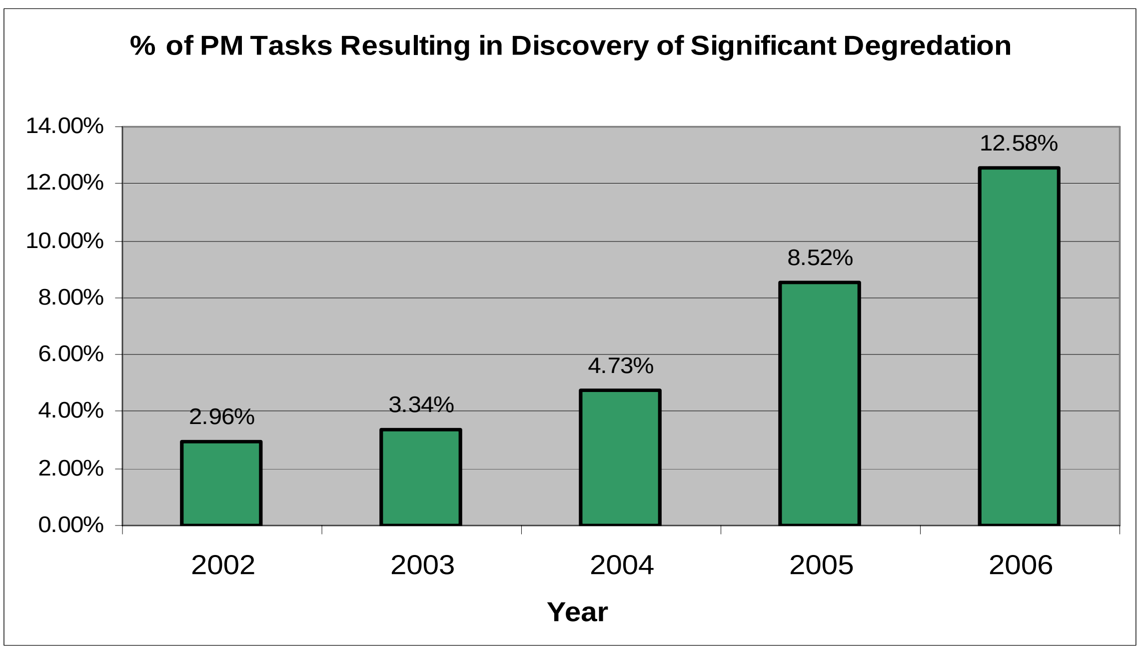
The Substation Maintenance Program is focused on maintaining or improving the reliability of 361 substations, utilizing low-cost, non-intrusive tasks to identify problems that could result in equipment failures, customer impacts, or expensive repairs. High-cost, intrusive tasks are used only when necessary to address incipient failures, or when degraded conditions could not be identified. In 2006, PSE increased reliance on non-intrusive diagnostic tasks through a new Transmission Oil Breaker Maintenance Program.

The maintenance program consists primarily of 21 different activities and approximately 8,000 tasks that are focused on the following:

- Substations which include monthly inspection and landscaping maintenance tasks.
- Transformers and Breakers which include electrical testing, oil analysis, physical assessments, infrared scanning, remote monitoring, and profile testing tasks.
- Batteries which include physical inspections, voltage, capacity, electrolyte strength testing and load testing tasks.
- Relays which include testing of distribution and transmission relays, trip circuits, reclosers, autoswitches and generation and intertie meter tasks.

Of the nearly 8,000 Preventative Maintenance (PM) activities that were performed in 2006, 970 of these (which accounted for approximately 14% of the substation maintenance budget) were analyzed to determine the number of corrective maintenance tasks that resulted from the PM activities. These 970 tasks were the focus of this analysis since they include the majority of the most expensive and most intensive maintenance tasks. In some cases, they can take several days to accomplish, and involve significant disassembly of the equipment that is being inspected. Of these 970 tasks, 12.58% resulted in the discovery of significant equipment degradation that could have compromised the equipment's ability to function and may have resulted in failure if not addressed. This is an increase from the 2005 value of 8.52%.

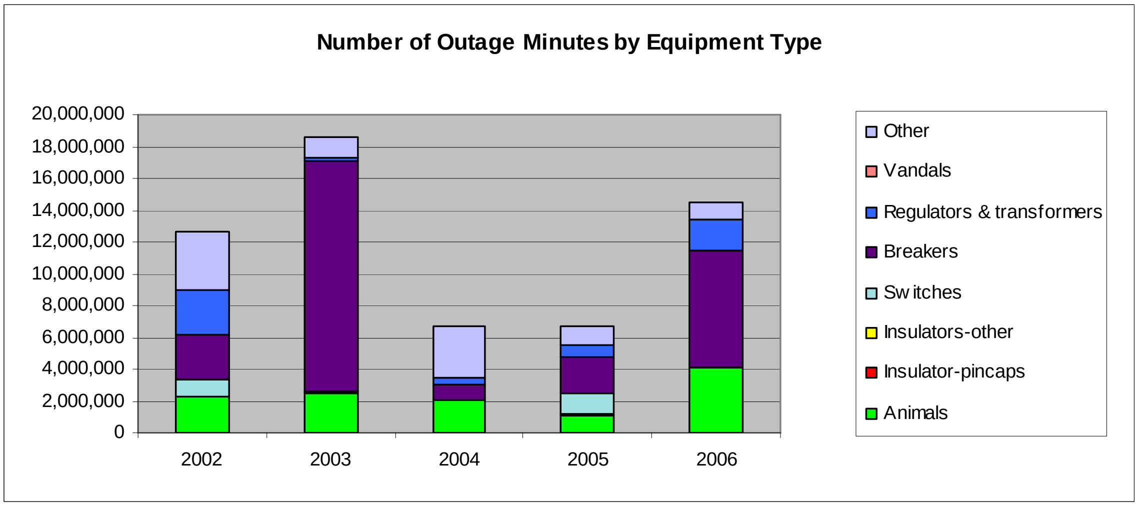
As shown in the graph below, more corrective maintenance is performed for every preventative maintenance activity.

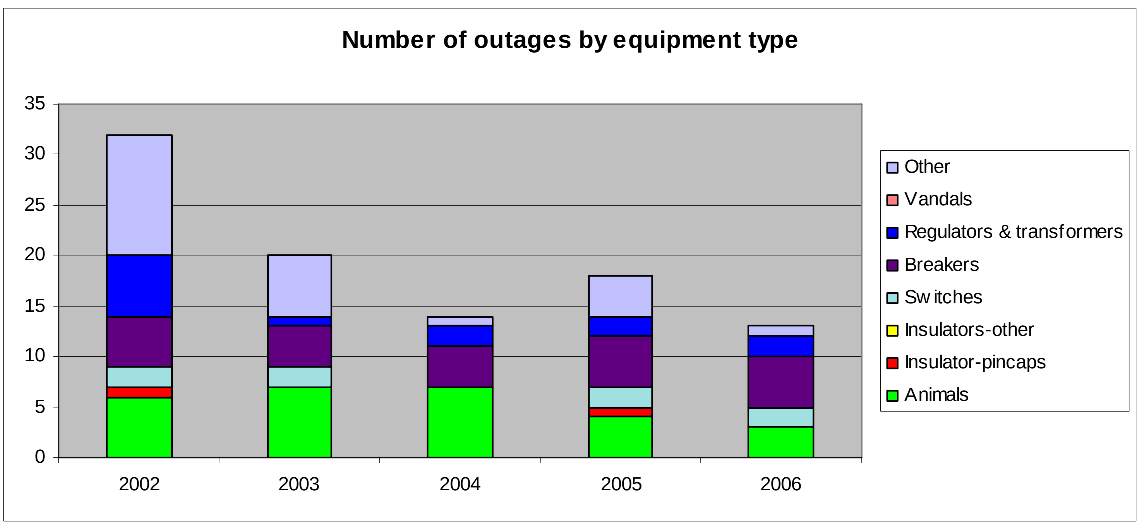


As projected in 2004, the percentage increased partially due to the implementation of the DADMO project. This system and associated processes provided the opportunity to analyze more maintenance tasks since almost all of the PM activities are now located in one company-wide database, and has resulted in more effective application of PM activities and more problems being documented.

In 2006, PSE experienced 13 substation outages as a result of equipment failures, accounting for 14,518,733 outage minutes. The number of malfunctions causing an outage decreased by 28% compared to 2005, while the number of outage minutes increased by 217% as compared to 2005.

The following graphs detail substation outage minutes and number of outages by equipment type. The outages and outage minutes tracked includes both storm and non-storm data.





Overall, outage minutes increased, while the number of outages per equipment type decreased to the lowest level seen since 1998. The increase in outage minutes is attributable to an increase in the duration of the outages that occurred. Outage duration increases were due to failures occurring in areas where system redundancy was low, resulting in longer restoration times.

Several areas of interest include:

- There were no outages associated with regulator and transformer failure, which is a reduction from the six-year average of three per year. This is partially attributable to the dissolved gas analysis (DGA) in oil-sampling program that allows the substation department to assess the condition of the transformer in a non-intrusive manner and at minimal cost, while identifying problems well before they result in significant damage or in interruption of service. In 2006, 585 DGA samples were evaluated. As a result, we avoided four possible transformer failures.

- There were no distribution pincap insulator failures in 2006. This represents a continuation of the relatively low failure rate since 2000, and compares very favorably to the failure rate of approximately five per year in the mid to late 1990s. As part of PSE's programmatic approach to replace all of these insulators, 808 insulators were replaced in 2006. At present budget levels, the remaining 6,387 pincap insulators are expected to be replaced by 2009. We're replacing these insulators in an effort to avoid failures that could potentially lead to safety and outage concerns.

- During infrared (IR) substation surveys, in 2006 we detected 33 problems prior to failure. This represents a significant portion of the equipment malfunctions detected during maintenance and inspection programs and is a good indicator that IR surveys will continue to be an effective diagnostic activity. Each year, more than 50% of all substations are planned to receive an IR survey.

- Outage minutes resulting from breaker failures increased from 2005. This increase is mostly attributed to a single transmission breaker failure that we were unable to be quickly restore, as work was being performed on an alternate feed. Although the number of breaker failures remained the same, the number of problems diagnosed prior to failure increased slightly. This is partially attributable to an inexpensive diagnostic test called breaker profiling. Profiling identifies developing problems with the breaker mechanism. In 2006, a significant effort was made to profile most of the power circuit breakers in PSE's system. In an average year, approximately 850 breakers are profiled. In 2006, however, we profiled 1,051 of our power circuit breakers. This represents 69% of the total breaker population. The remaining 31% will be placed onto the 2007 maintenance plan. The small percentage of the 31% that could not be profiled due to technical reasons or loading, will be investigated in 2007 to determine alternative methods of evaluation. Of the breakers profiled, seven were identified as having a developing or existing problem that may have prevented them from opening when ordered to do so. These seven avoided outages are a significant percentage of the total 32 avoided breaker outages in 2006, which reinforces the effectiveness of breaker profiling. Based on historical equipment failure impacts, profiling resulted in 4.1 million customer outage minutes avoided. The following table displays the results of the profile test over the last four years.

Profile Test Results

	2003	2004	2005	2006
Profile tests performed	745	681	1,355	1,051
Problems found	10	14	23	7
Percentage of breakers failing profile test	1.34%	2.0%	1.7%	0.7%

The percentage of breakers failing the profile test is expected to stabilize over the next several years with the continuation of re-lubrication of all of the breakers with higher performing lubricants.

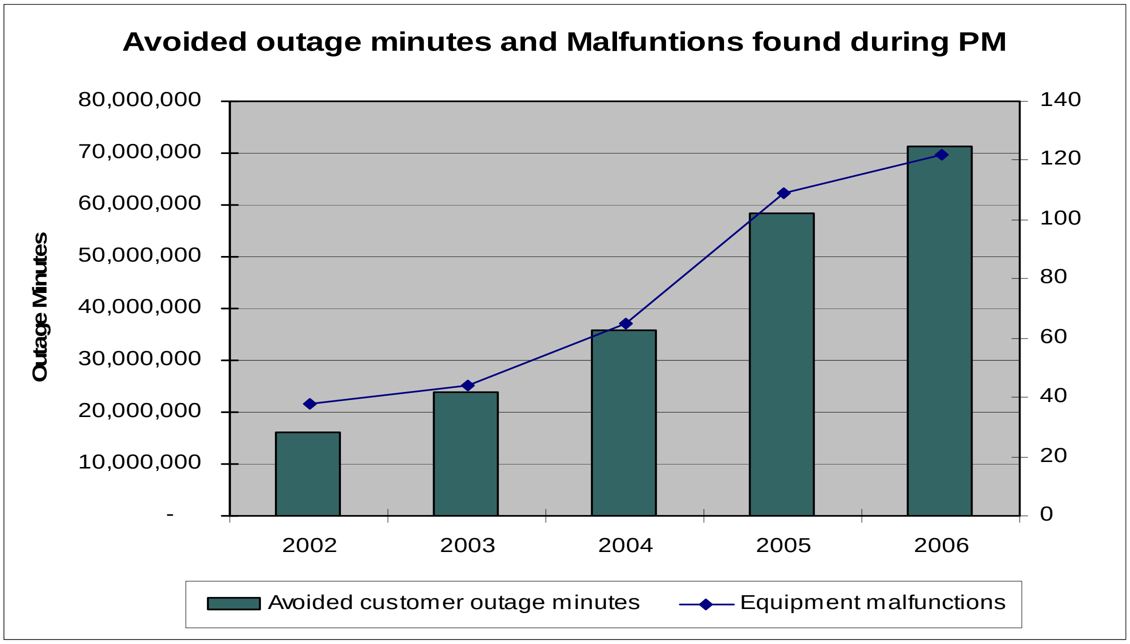
Of the 154 equipment malfunctions not causing an outage, 122 of them were identified during the course of equipment maintenance and inspection programs, or as the result of remote monitoring. Based on historical outage minute impacts of 583,231 per substation equipment failure, the substation maintenance program avoided an estimated 71 million outage minutes. This was accomplished by identifying these 122 malfunctions before they resulted in an outage. A breakdown of outage minute savings is provided in the table below:

Outage Minutes Saved by Equipment

Equipment type	2006 Avoided Outages	2006 Avoided Outage Minutes
Power circuit breakers	32	18,663,392
Transformers & regulators	30	17,496,930
Batteries and chargers	12	6,998,772
Relays	3	1,749,693
Connectors	10	5,832,310
Instrument transformers	2	1,166,462
Capacitor Banks	7	4,082,617
Switches	24	13,997,544
Other	2	1,166,462
Total	122	71,154,182

The 71 million customer outage minutes avoided in 2006 is a 22% improvement over 2005, which was estimated to have 58 million avoided minutes due to substation maintenance activities. The graph below demonstrates that we're identifying a greater number of developing or existing malfunctions during substation maintenance activities. Presented a different way, the data shows that for every malfunction that caused an outage, there were 11.9 that did not cause an outage. As a result of the greater number of malfunctions found during PM, more outage minutes were avoided.

Below is a graph that shows the avoided outage minutes and malfunctions that were found during PM.



Transmission Oil Breaker Maintenance Program - One of the revised programs implemented in 2005 and continuing through 2007, is the Transmission Oil Breaker Maintenance Program. The goal of this project is to analyze and justify an alternative method for determining the appropriate time to perform intrusive major maintenance on transmission class oil circuit breakers. This project will analyze the effectiveness of condition-based maintenance and its relative improvement over time and operations based system of PM. The new condition-based maintenance will use diagnostic tests to determine more conclusively when a circuit breaker should be taken offline. Using the specific diagnostic tasks outlined in the program, we identified 14 breakers that should be maintained in 2007. The program's projected cost savings for 2007 will be $245,518. This calculates to a 49% reduction in cost for Transmission Oil Breaker Maintenance.

There will be continued focus on non-intrusive maintenance programs such as the new transmission class oil circuit breaker initiative. During 2007, the data, comments and observations will be analyzed and compared to the success criteria. If the program success criteria are met, then it will continue. If the criteria are not met, then the program will be strengthened, improved and re-implemented with improvements for 2008.

IV. Industry Activities

Overview

PSE keeps current on emerging trends and industry best practices by bench marking ourselves against others, and by participating in professional organizations and industry groups. Employee participation in organizations such as the Western Energy Institute (WEI), American Gas Association (AGA), Canadian Electricity Association Technologies, Inc. (CEATI), Edison Electric Institute (EEI), and the Institute of Electrical and Electronics Engineers (IEEE) brings new ideas and concepts to the table. These activities enable our employees to proactively seek new and innovative ideas to solve the problems facing the integrity of PSE's system. Below are highlights of 2006 activities.

Western Energy Institute

PSE is a member of Western Energy Institute (WEI), a regional association serving the electric and gas industries, both public and private, throughout the Western United States and Canada. WEI sponsors many education and networking programs addressing strategic issues, informal bench marking of business practices and hands on technical training.

Technical experts representing a variety of fields discuss current affairs within the industry in response to a request by WEI's Program Delivery Team. PSE has provided a number of speakers. For example, speakers from PSE discussed WEI's 2006 - 2007 Strategic Issues, listed below:

Business Continuity Planning
- Developing New Training Initiatives
- Developing the Next Generation of Leaders
- Managing Stakeholder Relationships
- Sustain / Grow Earnings
- New Regulatory Initiatives

Customer Connections Section
- Manage Price Volatility
- Enhance Customer Confidence
- Grow Our Customer Base
- Embrace and Integrate Technology
- Educate Customers on Price Volatility
- Develop Best Practices

Operations Section
- Manage System Growth
- Maintain System Reliability & Infrastructure Needs
- Ensure Adequate Resource Supply
- Manage Price Volatility
- Public and Employee Safety
- Integrate Innovation and New Technologies
- Focus On Best Practices

American Gas Association

The American Gas Association (AGA) serves as an advocacy group for gas utility companies throughout the United States. The AGA advocates the interests of its energy utility members and provides information and services promoting demand and supply growth and operational excellence in the safe, reliable and cost-competitive delivery of natural gas. From an operations perspective, PSE plays an active role in the following committees:

- Accounting Advisory Council
- Accounting Principles Committee
- Accounting Services
- Compensation & Benefits
- Corrosion Control
- Customer Service
- Distribution & Transmission Engineering
- Distribution Construction & Maintenance
- Environmental Matters
- Environmental Regulatory Action
- FERC Regulatory
- Financial & Administrative Section Managing
- Gas Control
- Gas Piping Technology Committee (GPTC)
- Gas Transportation & Supply Operations Task Force
- Government Relations Policy
- Human Resources Policy
- Labor Relations
- Leadership Council
- Legal
- Legislative
- Membership Services
- Natural Gas Security
- Operating Section Managing
- Operations Safety Regulatory Action
- Plastic Materials
- Public Relations
- Rate & Strategic Issues
- Risk Management
- Safety & Occupational Health
- State Regulatory
- Strategic Marketing
- Supplemental Gas
- Underground Storage
- Utility and Customer Field Services

AGA also sponsors an "SOS program," whereby member utilities can quickly poll the entire membership regarding emerging issues. In 2006, PSE participated in several surveys of AGA member companies on topics ranging from commodities to employee safety. This program has proven very valuable in gaining an understanding of industry practices.

Canadian Electricity Association Technologies, Inc.

The Canadian Electricity Association Technologies, Inc. (CEATI) Distribution Asset Life Cycle Management (DALCM) interest group is an association of electric utilities that direct research funding to develop applications and technology designed to maximize electric distribution asset life. PSE joined DALCM in 2004. The research consortium consists of approximately 20 utilities, primarily Canadian but with a few U.S. members. Two overseas utilities have recently joined the consortium.

Recent DALCM research includes a Distribution Technology Road Map. The Distribution Technology Road Map is a recommendation of how utilities will prepare for the technology changes that will affect how they will build their distribution systems. The focus is to meet customer expectations in the future, relying more on automation technology than is now employed. The objective of Phase II is to develop an actionable plan from the Phase I Technology Roadmap that can be followed by the distribution utilities to justify and implement the technology initiatives required to meet current and future business needs. The approach for this phase involved initiating the following three work streams:

- Planning for Now & 2010—to identify the key technologies required by the distribution utilities in the next five years and beyond
- Common Infrastructure—the underlying common infrastructure including the enabling technologies needed
- Case for Change—allows the distribution utility to assess its readiness for change, effectively communicates the need for change to key stakeholders and provides guidelines for transforming into the distribution utility of the future

Projects also funded, in part by PSE, develop techniques for Remedial Treatment of Utility Poles Using Borate Rods and In-Situ Butt Encapsulation, Deficiency Ranking Methods for Distribution System Inspections, Short-Circuit Cable Rating, Implementation Roadmap for Utilities Deploying Broadband Over Power Line Networks, and continue development of the Fault Alert technology.

There will be further development of technology applications recommended in the Distribution Technology Road Map. PSE has utilized a report by CEATI regarding Evaluating the Efficiency of Energy Systems to predict circuit imbalances for reducing losses. Through another CEATI report, PSE has also gained validation that the best technology is being used to determine corroded neutrals.

DALCM also provides a forum for presentation and discussion of innovative solutions to distribution system challenges.

Edison Electric Institute

PSE is an active member of Edison Electric Institute (EEI). Operations employees participate in five committees:

- Emerging Issues
- Transmission Committee
- Power System Planning Operations
- Steering Committee – attended at the vice president level
- Spare Transformer Equipment Program

EEI's U.S. members serve almost 95% of the ultimate customers in the shareholder-owned segment of the industry, and nearly 70% of all electric utility ultimate customers in the nation. In addition, members generate over 70% of the electricity produced by U.S. electric utilities.

Organized in 1933, EEI works closely with all of its members, representing their interests and advocating equitable policies in legislative and regulatory arenas. In its leadership role, EEI provides advocacy, authoritative analysis, and critical industry data to its members, Congress, government agencies, the financial community and other opinion-leader audiences. EEI provides forums for member company representatives to discuss issues and strategies to advance the industry and to ensure a competitive position in a changing marketplace.

PSE collaborated with many other utilities to support the EEI's Spare Transformer Equipment Project. This project was initiated by EEI, with the goal of establishing a pool of critical power transformers that could be used to replace units that were rendered unusable due to a triggering event such as the deliberate destruction of utility substations. Under this agreement, participants would be obligated to provide spare transformers to other participants who experienced loss of a transformer as the result of a triggering event.

Forty-seven utilities have committed to support this project by ensuring availability of transformers in up to nine different transmission voltage classes. PSE has committed to participate in the 230 - 115 kV voltage class for this project.

Institute of Electrical and Electronics Engineers

IEEE has advanced the theory and application of electric technology and sciences. It serves as a catalyst for technological innovation and supports the needs of its members through a wide variety of programs and services. The IEEE is a non-profit, technical professional association of more than 360,000 individual members in approximately 175 countries.

The IEEE's Power Engineering Society is involved in the planning, research, development, construction, installation, and operation of equipment and systems for the safe, reliable, and economic generation, transmission, distribution, measurement, and control of electric energy. It provides a conduit of current power engineering information through meetings, journals, conferences and standards to its members.

PSE has many active members of the Institute of Electrical and Electronics Engineers (IEEE). The IEEE and its predecessors, the AIEE (American Institute of Electrical Engineers) and the IRE (Institute of Radio Engineers), date back to 1884.

In 2006, PSE engineers participated in IEEE working group meetings for:

- Distribution Reliability
- Switching and Over-current Protection
- Distribution Automation
- Distribution Resources Integration
- Electrical Testing of Wildlife Protectors
- Distribution System Performance
- Voltage and VAR Control
- Stray Voltage
- Substation Grounding Standards

IEEE Seattle Section and PSE volunteers help sponsor the National Engineers Week Future City Competition. It is a program for seventh and eighth-grade students to foster interest in math, science and engineering through hands-on, real world applications.

IEEE Insulated Cable Committee

Insulated Conductors Committee (ICC) is a professional organization within IEEE. Its mission is to improve the technology, understanding, practical application and safe use of underground conductors. The committee meets biannually and with typically more than 350 participants. It has about 30 subcommittees that address a multitude of facets dealing with underground cables, connectors and terminations. PSE is actively involved and participates in the leadership of this committee.

Industry Benchmarking

In support of continuous improvement and performance comparison, PSE Operations participates in several proprietary* industry benchmarking programs. These specifically cover areas of operational efficiency and system reliability and integrity. This data helps PSE understand where we are in comparison to other utilities for use in determining whether focused improvement efforts are needed or desired.

- Periodic participation in American Gas Association's Best Practices Benchmarking Program which typically covers five to six topical areas and overall gas utility operations (PSE will not participate in the 2007 program, which utilizes 2006 information)
- American Gas Association's Uniform Statistical Report, which covers overall gas utility operations
- Edison Electric Institute's annual electric system reliability study, which covers SAIDI, SAIFI and CAIDI measures

- Institute of Electrical and Electronics Engineers (IEEE) electric system reliability study, which covers SAIDI, SAIFI and CAIDI measures
- Periodic participation in studies by UMS, FMI, Navigant, or others to better understand best practices across multiple operations
- Periodic participation in surveys through working groups of these organizations as other utilities or PSE have specific interest in how a practice is employed

PSE benchmarks itself against other gas utilities in "repaired gas leaks per mile of main or per service." Additionally, PSE benchmarks itself against other utilities in non-production O&M cost per customers on a gas, electric and combination utility basis.

* Many of these studies contain strict confidentially requirements and are intended for internal use only.

NERC Compliance

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; PSE is preparing to comply fully with these requirements. 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.

V. Innovations, Initiatives, & Challenges

Overview

Challenges continue to exist as PSE strives to maintain our edge in providing safe reliable energy service at low cost. It's through industry activities and innovated thinking that PSE will continue to be a best in class performer. This section describes process improvements, new initiatives, technology applications and challenges that PSE system performance programs are focusing on in 2007.

Automatic Meter Reading

In September 2006, PSE converted the last 75,000 of approximately 1.75 million meters to the Automated Meter Reading (AMR) system. A majority of these meters are read by the Cellnet AMR system. This AMR network continues to improve in performance and provides daily reads and status information of the automated meters. In addition, PSE has continued to build out the functionality of our Meter Data Warehouse (MDW) to store, analyze, and integrate the data from the AMR system with other processes within the company.

In 2006, we continued to build and test enhancements to the MDW in order to add further functionality to better manage the metering system and to provide data to groups outside of the standard meter reading process. These enhancements included: updated outage interpretation, including advanced mapping of outages, integration with PSE's outage tracking system, a real-time dashboard of outage status by county, and improved restoration verification tools,. These enhancements continued to improve PSE's response to outage events. Also, it allowed PSE to mine the warehouse data for anomalies, which generates meter investigations in a more timely and reliable manner. This reduced the amount of physical meter reads required, and provided good weather and interval data for rate development and load research groups.

AMR improved system performance by identifying outages before customers call, improving the restoration process, compensating for missing and inaccurate connectivity data; improving switching procedures; helping PSE manage scheduled outages better, formulating more cost-effective asset maintenance plans; and facilitating system planning and engineering for lowering interruption frequencies.

AMR is beginning to evolve into Advanced Metering Infrastructure (AMI). AMI is the enabler of what many are saying is the next revolution in our industry—the intelligent grid. From time-based rates and load control applications to integrated demand response for spinning reserves and transmission congestion, the vision of what this grid could mean to the industry is vast, even though it is still evolving

The benefits of implementing AMI on the Transmission and Distribution (T&D) systems can be grouped into three categories:

1) Demand reduction benefits;
2) Outage management benefits; and

3) Significant other efficiencies and related benefits including providing foundational technology for projects such as system automation and the smart grid concept.

T&D demand reduction benefits include the deferral of transmission line projects, the deferral of distribution capacity projects and avoided distribution capacity additions. The T&D outage management benefits include a reduction in labor associated with the response to customer outage calls, automatic outage analysis, crew deployment improvements and emergency and planned switching support. The outage management benefits included here are for normal and storm operations. The other efficiencies and related benefits include the improvement of load forecast accuracy, elimination of drag hand reads and elimination of transformer load reads.

Customer Care

PSE responds to customer complaints about reliability and power quality through a process established in 2001 that tracks customer complaints in Consumer LinX, PSE's customer information system. This process ensures follow-up with all customers who have commented about outages and/or power quality more than one time in a 24-month period and identifies areas of greatest concern geographically.

In 2006, PSE received 19 reliability complaints and four power quality reports. The WUTC received an additional 56 reliability complaints. This total of 79 reliability/power quality complaints represents an increase from 2005, where the complaints totaled 53.

Note, there were 225 complaints in 2004, most of which we received in response to a mailing to impacted customers following back-to-back storms. PSE has worked diligently to communicate with customers about their concerns and questions. This communication continues to be beneficial in directly identifying concerns and establishing opportunities to collaboratively find effective solutions.

Smart Grid – 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. Smart Grid can only be applied if there is a communications infrastructure available to integrate the intelligent devices. That communications infrastructure will need to have two way capabilities. That is, we must be able to send and receive data. We do not presently have that infrastructure.

While Smart Grid is less developed than DER technologies, it 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.
- Smart 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.

- It would support widespread use of distributed energy resources, meaning a standardized power and communications interfaces would allow customers to interconnect fuel cells, renewable generation, and other small-scale generation on a simple "plug and play" basis.
- It 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.

Once a communication infrastructure is available, some near-term benefits include:

- Monitoring load balance on distribution lines to optimize and reduce losses on the distribution system,
- Control of regulators to provide voltage levels that would increase energy efficiency,
- Provide remote control of switching devices,
- Locate power quality problems before a customer complains
- Locate fault locations prior to sending serviceman

Some long-term benefits include:

- Grid upgrades that increase the amount of power that can be moved through the transmission grid and that optimize those power flows will reduce waste and maximize use of the lowest-cost generation resources.
- Interfaces between the grid and the energy management systems of buildings and other loads will enable residential, commercial, and industrial consumers to manage electricity use in a manner that improves efficiency and reduces consumer costs.
- Technology upgrades in the areas of transmission and distribution system monitors, information systems, and power flow controls would enable the grid to be "self healing" by permitting grid controllers to anticipate and instantly respond to system problems in order to avoid or mitigate power outages, power quality problems, and system damage. This would benefit high-tech consumers and others who require a stable and reliable power supply.

Engineering Matters

Engineering Matters is a PSE employee group that meets regularly to present and listen to internal and external speakers for the purpose of:

- Providing a supportive, informal learning environment for PSE engineers to maintain and share technical and business knowledge.
- Developing new engineers and strengthening the knowledge base of seasoned engineers.
- Fostering teamwork by providing an open environment for employees to spend time together and get to know one another.
- Providing discussions on any topic in which the speaker has some expertise and will be of interest and value to the participants.

Engineering Matters provides an opportunity for training and professional growth. PSE employees can learn about evolving technologies and a wide array of other topics that affect the company. It can be used to develop speaking skills and to promote cross department discussions.

Topics in 2006 included:

- Voltage Flicker
- Risk and Claims
- Cable Neutral Corrosion
- ION Meters
- Pacific Northwest National Laboratories
- SEL Loop Feed
- Optic Sensors CT's & PT's
- Disturbance Monitors
- GIS and other IS initiatives
- Synchrophasors
- Columbia Grid
- Generation Multi-resolution Modeling
- Pacific Northwest Locational Marginal Pricing
- Alaska's Electric system
- Fuseless Capacitor Banks

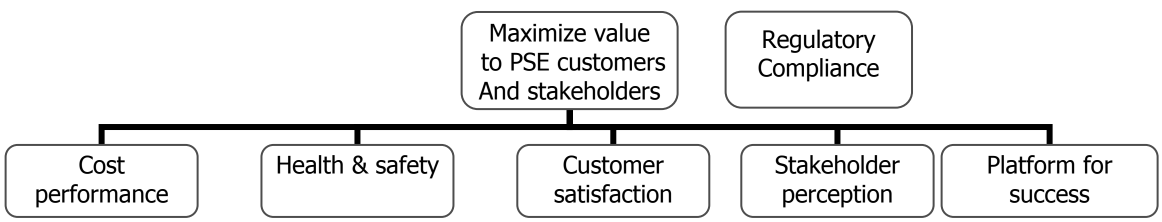
Total Energy System (TES) Process

Delivery system planning employs processes that ensure the gas and electric energy delivery systems are integrated to provide safe and reliable service at the lowest cost. Within this integrated view, delivery system planning establishes the guidelines for installation, maintenance and operation of the company's physical plant, while balancing cost, safety, and operational requirements. The delivery system planning process also considers environmental management, regulatory requirements and changing customer demands as it reviews cost-effective alternatives and develops contingency plans.

In 2005, the T&D Asset Investment Optimization System was updated 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, 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.



Distributed Energy Resources

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.

Essentially, distributed energy is a way of incorporating small-scale generation into the grid closer 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 Peninsula 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 in 1999, PSE implemented a distributed resource peak shaving strategy 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. We 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.

Distribution Integrity Management

In 2004, the Department of Transportation (DOT) Inspector General (IG) suggested that application of integrity management (IM) principles could help improve the safety of gas distribution pipelines. In testimony before Congress in July 2004, the IG recommended that the Pipeline and Hazardous Materials Safety Administration (PHMSA) require operators of distribution pipeline systems to implement some form of integrity management or enhanced safety program with elements similar to those required in hazardous liquid and gas transmission pipeline integrity management programs.

In response to this recommendation:

- PHMSA developed a high level flexible regulation for distribution integrity management;
- The Gas Pipeline Technical Committee (GPTC) formed a team and drafted Distribution Integrity Management Program (DIMP) Guide Material that would be incorporated by reference in the federal rule.

The proposed federal rule for distribution integrity management is expected to be posted by September 2007, with a final rule expected to be released in December 2007. The GPTC DIMP Guide Material was issued as a final draft in October 2006 and is awaiting the release of the proposed rule to incorporate additional edits as needed.

The fundamental principles of distribution integrity management require an understanding of the infrastructure of the distribution system and the risks it poses, and then taking actions to address those risks. GPTC DIMP Guide Material indicates that the regulation will require operators to prepare a written plan (anticipated to be due by December 2008) and implement a DIMP (anticipated to be due by December 2009). This material also identified seven elements as the essential components of a DIMP, as follows:

1. Know the distribution systems and how these are operated and maintained.
2. Identify the threats to address associated risks.
3. Evaluate and rank groups based on associated risks.
4. Identify and implement appropriate measures to manage risks.
5. Measure performance and monitor results.
6. Periodically evaluate and improve the program.
7. Make periodic reports to government agencies as required.

It is anticipated that the regulation will require an operator's written plan to include all of the seven elements stated above.

In 2007, PSE will form a project team assigned to identify and evaluate our options to comply with DIMP. Additionally, the team will begin work on recommended solutions, schedules, and plans to ensure we meet DIMP compliance deadlines.

Future Performance Targets

In 2006, TESP and SMP initiated development of business cases focused on several measures of delivery system performance. This work built on efforts that took place as early as 2004, when the teams set high level system performance targets to focus our asset management efforts and support high level spending targets. In 2007, business cases will be completed for Electric System SAIDI, SAIFI, Electric System Utilization, Gas System Utilization for High Pressure Piping, and Gas System Utilization for Intermediate Pressure Piping.

The business cases include a discussion of historical performance levels, short and long range performance targets, and the resultant business impacts; they also include detailed information that will be used as infrastructure planners develop plans and budgets for future years. In addition to justifying our planning efforts and spending targets, these business cases have provided insight into and transparency of our long range system plans. The latter has increased communications between planning and work execution teams, which has resulted in ideas that could improve our project delivery efforts. Ideas under consideration include levelizing substation construction plans (an initial analysis has revealed that this would ease workload fluctuations for project delivery teams, with no material reduction in electrical system performance over the long term). Other results of the business cases include recommendations to increase spending on projects that reduce outage duration, and increasing our focus on certain types of gas system leaks that do not require immediate repair.

2007 Challenges

Aging infrastructure, changes in the industry and increasing sensitivity to energy costs, electric system reliability and environmental impact make delivery system planning and operations an evolving and complicated process. In addition, these processes are 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.

Although we believe we have a strong planning process and excellent engineering practices, we see opportunities to strengthen our performance. We are restructuring our planning process to improve service to our customers and increase our efficiency and effectiveness. We are preparing our workforce for the future; we are also evaluating our processes, investigating automated solutions, and enhancing employee development. Finally we have set our key performance targets for the next 10 years to achievable levels for a best in class gas and electric company.

Acknowledgment & Contact Information

Total Energy System Planning and System Maintenance Planning spent a significant amount of time working to identify system problems or opportunities, developing solutions, testing them, and justifying expenditures to support the solution. Planning a reliable energy system is a team effort, which involves many other people and departments. We acknowledge the many different teams that contribute to the delivery of the projects within the plan. These teams include: Safety, Standards, Engineering, Communications, Project & Construction Management, Materials Control, System Control, Real Estate, Community Services, Field Operations, Contractor Management, and many others. Their efforts and contributions are appreciated.

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We appreciate the continued interest in the information contained in this report, and we hope you have found it to be of value. In the event that you would like to discuss this information in more details, ask questions, or request a presentation to your team, we invite you to contact either of us at your convenience.

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