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After-action review of December 14-15, 2006 Windstorm

Update on actions taken by Puget Sound Energy to address KEMA and supplemental recommendations

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PSE ACTION UPDATE

KEMA after-action review of December 14–15, 2006 windstorm *"Hanukkah Eve Windstorm of 2006"*

Update on actions taken by PSE to address KEMA and supplemental recommendations

Dated August 31, 2008

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INTRODUCTION

On November 29, 2007 Puget Sound Energy (PSE) provided to the Washington Utilities and Transportation Commission (UTC) a summary of the KEMA recommendations and subsequent actions taken by PSE (the Report, included as Exhibit A – 11/29/2007 PSE Response to KEMA Report). This supplemental update provides a summary of further actions taken by PSE on the KEMA recommendations since the Report. In addition, it provides an update on actions taken on those recommendations identified in Exhibit 13.4.1-A of the Report, the Recommendations Matrix. The recommendations in Exhibit 13.4.1-A of the Report were generated from internal storm debriefs and visioning exercises, the Governor's After Action Review, and customer focus group and survey input and were supplemental to the KEMA recommendations. An update to the Recommendations Matrix was provided as part of a General Rate Case (GRC), Docket numbers UE-072300 and UG-072301, in response to Data Request #54 from the UTC Staff and is included as Exhibit B – Data Request #54.

As noted in this update, PSE has accepted and implemented most of these recommendations and they are now integrated into PSE's emergency preparedness processes. PSE will continue to refine these processes as a result of post-event and annual reviews. Future UTC updates will address those items noted in this report that are being pursued but are not complete or are still under consideration.

UPDATE ON KEMA RECOMMENDATIONS

4.4 EMERGENCY RESTORATION – ANNUAL PLANNING RECOMMENDATIONS

4.4.1 Expand the company emergency response capability through enhanced personnel utilization.

PSE actions:

PSE noted in the Report that PSE accepted KEMA's recommendation.
Subsequent to the Report, PSE's emergency planning manager followed up with nine PSE employees who did not participate in 2007 damage assessment training to determine what training was needed, or whether they should remain assigned to damage assessment. In addition, the five individuals who missed the Emergency Operations Center (EOC) orientations were contacted and individual EOC orientations were conducted.

Emergency Response positions have been identified for PSE and its Service Providers (Exhibit C – Lists of Damage Assessors). Training and orientation is done annually and is under way for the upcoming 2008/09 storm season. Materials covered during this training and orientation are provided in Exhibit D – Damage Assessment Training Guide. Mock storm/emergency communication exercises were conducted on August 7 and August 28 2008 with two additional exercises scheduled in September 2008.

PSE will host 2008 "pre-winter storm" meetings in late-September to mid-October with eight county emergency management agencies. PSE's electric first response supervisors and Potelco operating base managers will participate, to ensure contact information is shared with the county agencies. Topics of the presentation will include information on PSE's storm planning, employee storm training, mock exercises, lessons learned from the December 2006 windstorm, actions taken as a result of the KEMA recommendations and the Governor's After Action Review. Meetings will be held in Whatcom, Skagit, Island, King, Pierce, Thurston, Jefferson, and Kitsap Counties.

These steps are now a normal part of PSE's emergency preparedness process, although continued refinement is expected with the company's annual process review. This item is considered completed, and will not be addressed in future reports to the UTC.

5.4 EMERGENCY RESTORATION – IMMINENT EVENT PLAN RECOMMENDATIONS

5.4.1 Develop a storm categorization methodology and tailor aspects of the Corporate Emergency Response Plan (CERP) to the various levels of storms.

PSE actions:

PSE noted in the Report that PSE accepted KEMA's recommendation.

PSE updated its CERP plan by year-end 2007 (Exhibit E – 2007-2008 Corporate Emergency Response Plan). The CERP is now based around the implementation of the emergency event levels shown below (to be used for both electric and natural gas events):

Levels	Electric Criteria	Gas Criteria	Level of Response
Level 0 - Normal	Nominal conditions across system.	Nominal conditions across system.	Normal daily response activity.
Level 1 - Regional	Event localized to individual geographic areas; resources within region adequate for response.	Localized event managed with regional resources.	Operations base(s) open; coordination with system operations or gas control. Gas Planning Strategy Center opens for gas emergencies.
Level 2 - Significant	Multiple regions affected; requires resources from other PSE regions and/or outside PSE service territory.	Multiple regions affected; requires resources to be allocated to other PSE regions.	EOC open; multiple operating bases and may activate local area coordination. Employees with emergency response assignments mobilized.
Level 3 - Major	Most or all regions affected; maximum level response required; need extensive resources from outside area.	Most or all regions affected; may request operator qualified resources from outside PSE.	EOC open; most or all operating bases open; external logistics support may be employed; full corporate response to support restoration efforts.

Departments such as Operations, Customer Service, and Corporate Communications use the above matrix to drive departmental specific response actions. Below are expected actions to be taken based on the storm level declared:

Levels	Operations Actions
Level 0 - Normal	Normal operations.
Level 1 – Regional	EOC not opened. Internal resources utilized. Some use of employees with Emergency Response (ER) assignments.
Level 2 – Significant	EOC opened. Additional contractor resources needed; some from bordering states. Moderate to extensive use of employees with ER assignments. Windshield assessment utilized. Complete assessment within 24–36 hrs. Local Area Coordination possible.
Level 3 – Major	EOC opened. Resources obtained from outside of region. Full utilization of employees with ER assignments. Local area coordination implemented. Windshield assessment utilized; complete assessment within 48–72 hrs.

Regardless of event level, once damage assessment is underway, PSE's goal is to communicate to customers and communities the overall scope or projected duration of the restoration effort within 24 hours, (e.g., Restoration efforts are estimated to last 4 days); communicate regional or county level restoration estimates within 48 hours, (e.g., Thurston County customers are estimated to be restored by 12 midnight, Friday); and community restoration estimates within 72 hours, (e.g., Customers in Bellevue are estimated to be restored by 6 a.m. on Saturday). In addition, PSE is reviewing basic storm data collected since 2002 which includes summary information at a company level. This data will be used as an initial source of information for general estimates of restoration time ranges and will continue to be updated.

These steps are now a normal part of PSE's emergency preparedness process, although continued refinement is expected with the company's annual process review. This item is considered completed, and will not be addressed in future reports to the UTC.

6.4 EMERGENCY RESTORATION—EVENT ASSESSMENT RECOMMENDATIONS

6.4.1 Enhance the damage assessment capability and process to provide better and faster estimates of restoration times and resource requirements.

PSE actions:

PSE noted in the Report that PSE accepted KEMA's recommendation.

For 2008/09, PSE has increased the number of damage assessors from the 79 assigned in winter 2006/07 to a current pool of 202. 105 PSE employees have "Damage Assessor" (DA) as their primary storm role and another 97 have damage assessment as their secondary role. Potelco has identified 44 DAs for a combined total of 246 potential DAs. Training for the 2008/09 storm season will be completed by the first week of October.

Building on last year's DA training program enhancements, a dedicated Damage Assessment Training Guide for 2008/09 was created. A copy of this comprehensive guide (Exhibit F - Damage Assessment Training Guide) is being provided to each DA in class and copies of the guide will also be inserted into storm bags stored at each operating base.

To enhance our damage assessment "bench strength," PSE will continue to classify damage assessors into A and B Teams. "A Team" assessors are those having greater experience or, are employees who work with the electrical system in a technical manner; "B Team" assessors are those with less experience. In smaller events, A and B Team assessors will be paired together to facilitate cross-training. In large events, A and B Team assessors will be paired with a driver and fielded independently to ensure maximum resource utilization.

PSE retained KEMA to assist in developing a damage assessment strategy based on historical data (system damage, weather, restoration times, etc.) to further enhance our ability to provide early restoration estimates. Additionally, KEMA was tasked with examining leading damage assessment practices in the industry in modeling storm damage and corresponding restoration time estimates.

To better address PSE's current technological state, PSE refocused the KEMA analysis from damage data collection/analysis to industry-leading damage assessment practices. KEMA completed its survey and provided PSE a report in May 2008 (Exhibit F – Damage Assessment Practices). Most of the utilities utilizing an integrated Outage Management System (OMS) reported favorable experiences with those systems during storms. There was some use of mobile data terminals and some have implemented consistent span(s)-of-control between DAs and the number of fielded teams. Some utilities appear to engage in some form of windshield assessment.

In general, the results of the survey affirmed that PSE's current damage assessment practices are valid based upon the current outage technologies utilized. Through training, Damage Assessors will be made aware of PSE's commitment to provide corporate and regional estimates to customers by the 24, 48, and 72 hour time frames. They will be made aware of their role and how it fits in determining these estimates.

These steps are now a normal part of PSE's emergency preparedness process, although continued refinement is expected with the company's annual process review. PSE's investigation into the possible implementation of an OMS and DA mobile tool may lead to further refinements in the damage assessment process including improved historical data analysis. If such tools are implemented by the company, further reporting on their impact will be provided in future reports to the UTC.

7.4 EMERGENCY RESTORATION – EXECUTION RECOMMENDATIONS

7.4.1 Institute consistent accountability for executing the storm plan.

PSE actions:

As noted in the Report, PSE believes that the appropriate level of accountability currently exists and with its Service Providers. Ultimate responsibility for storm restoration belongs to PSE which, in addition to the Service Providers, utilizes PSE resources and additional outside contractors to assess and restore service to its customers. These efforts are scaled depending on the declared storm level and all pre-storm training and orientations reinforces the expectations for the 24, 48, and 72-hour communication milestones identified for each storm level. This item is considered completed, and will not be addressed in future reports to the UTC.

The Potelco/PSE Fall Joint Leadership Meeting is scheduled for October 10, 2008. Agenda items include the National Weather Service's long-range winter forecast, key leadership messages, and a review of Corporate Emergency Response Plan updates/changes. EOC and operating base orientations are being held in October.

These steps are now a normal part of PSE's emergency preparedness process, although continued refinement is expected with the company's annual process review.

7.4.2 Formalize local area coordination and transmission restoration priority activities.

PSE actions:

PSE noted in the Report that PSE accepted KEMA's recommendation.

For the 2007/08 storm season, PSE documented its Local Area Coordination (LAC) and Transmission Restoration Team plans and inserted them into EOC and Operating Base Plan documents. Preliminary LAC sites have been identified and associated resource plans completed. PSE has contracted with Base Logistics to provide site plans for regional staging areas as well as LAC sites. PSE will review LAC and staging locations at 2008 "pre-winter storm" meetings in late September to mid October with eight county emergency management agencies. Working with local jurisdictions, PSE will explore the feasibility of using LAC sites to also coordinate broader jurisdictional emergency event management (e.g. local road clearing task force efforts).
Local area coordination plans will be exercised as a part of the 2008 mock storm exercises.

These steps are now a normal part of PSE's emergency preparedness process, although continued refinement is expected with the company's annual process review. This item is considered completed, and will not be addressed in future reports to the UTC.

8.4 EMERGENCY RESTORATION – EXTERNAL COMMUNICATIONS RECOMMENDATIONS

8.4.1 Create an integrated corporate and local communication strategy that is scalable to storm severity.

PSE actions:

As noted in the Report, in accepting KEMA's recommendation PSE has developed a scalable communication strategy that provides accurate and consistent information to customers by way of various communications channels, including:

- A brief recorded message about the disrupted service all customers hear upon calling PSE including, when applicable, information pertaining to the 120 consecutive-hour outage service guarantee that is part of the settlement in the GRC
- Reports to the news media,
- Key messages delivered by PSE's government and community relations managers (CRMs) to local jurisdictions and emergency management agencies and by major accounts and business services representative to major customers, and
- Web information posted to www.PSE.com.

For the 2008/09 storm season, PSE is refining a Web-based Service Alert Map display that will be available at www.PSE.com (Exhibit G – Web-Map Display Demo). The outage map display will be enabled during Level 2 and 3 events to help communicate the overall outage impact and restoration progress across PSE's service area. Implementation is anticipated in October 2008.

PSE has conducted two tabletop exercises specific to storm communications in 2008 with the first having occurred on August 7 and the second on August 28. Exercise objectives for these tabletops were as follows:

- Following the storm communications plan,
- The formulation and communication of 24, 48, and 72-hour messaging, and
- Coordination and consistency of messaging between Corporate Communications, Access Center, Community Relations, Major Accounts, etc.

These steps are now a normal part of PSE's emergency preparedness process, although continued refinement is expected with the company's annual process review. This item is considered completed, and will not be addressed in future reports to the UTC.

9.4 EMERGENCY RESTORATION – CUSTOMER SERVICE RECOMMENDATIONS

9.4.1 Formalize a customer escalated call process.

PSE actions:

PSE noted in the Report that PSE accepted KEMA's recommendation.

For 2008/09, PSE has identified 15 employees to serve in the capacity of Communications Lead (Exhibit H – PSE Communication Lead Assignments). (Role description is provided below.) This new communications function will be exercised as a part of the 2008 mock storm exercises. This process is also supported by the Bothell Emergency Center which has been created to facilitate operations at PSE's Bothell Access Center (Call Center) during emergency events by pre-assigning job duties and responsibilities (Exhibit I – BEC Duties and Responsibilities).

> **Communications Lead**
>
> The Communications Lead responds to specific customer inquiries from major account or key business customers (e.g., schools, healthcare facilities, grocery store chains, area shelter locations, etc.). Works with the Major Account Representative(s) in the EOC to coordinate major and key customer response.
>
> Takes escalated call inquires from the EOC, Customer Access Center, or the Executive Office providing information for specific customers. Researches status of outage and restoration efforts for specific customers as required. Works closely with Storm Board Coordinator to gather information. Work location is the storm operating base.

These steps are now a normal part of PSE's emergency preparedness process, although continued refinement is expected with the company's annual process review. This item is considered completed, and will not be addressed in future reports to the UTC.

9.4.2 Use local carrier phone network in front of CLX/IVRU to enhance call-taking capacity and capabilities.

PSE actions:

As noted in the Report, PSE accepted KEMA's recommendation in concept with implementation in two phases.

Phase I is complete and will be implemented for emergency events when community messaging is necessary. The plan uses Qwest's (local carrier) EZ Route IVRU in conjunction with PSE's IVRU to overflow callers to a recorded message with information specific to their community based on their automatic number identifiers (ANIs) (for PSE's IVRU) or zip code (for Qwest IVRU). Customers will have the opportunity to be re-routed back to PSE if they wish to speak to a live representative. The Community Messaging System was moved into production in May, 2008.

For Phase II, PSE investigated KEMA's recommendation to use the local carrier phone network in front of PSE's CLX/Interactive Voice Response Unit (IVRU) to enhance call-taking capacity. KEMA identified the benefits as ability to handle a greater volume of calls, use automatic number identification to give customers unique restoration messages, and reduce the number of inbound trunks necessary at PSE. PSE worked with Qwest to cost out a solution for providing 500 ports. The cost quote was a $58,375 monthly service charge (approximately $700,000 annually) and a one-time $80,000 - $100,000 development cost. A seasonal service option was not available. While the additional ports would provide increased capacity for customers to listen to outage messages in their area, there are concerns. It is possible a customer would be given incorrect information should they be calling from a phone other than the location of the outage. Based on the cost and the value added PSE is not moving forward with Phase II.

This item is considered completed, and will not be addressed in future reports to the UTC.

10.4 EMERGENCY RESTORATION – INFORMATION SYSTEMS AND PROCESSES RECOMMENDATIONS

10.4.1 Establish enterprise-level technology, data, and integration architecture for outage management related processes.

PSE actions:

PSE has accepted KEMA's recommendation and is initiating the next phase of planning and analysis of various implementation scenarios for a Geographic Information System (GIS) and an integrated Outage Management System (OMS). PSE recognizes that a thoughtful plan and implementation is required to recognize benefits and to clearly understand the extent of business process, workflow, organizational and competency changes necessary to realize them.

As noted in the Report, PSE engaged KEMA to further define what a new, enterprise-level architecture for integrating technology and data for outage management might require and cost. Their work included defining a new system connectivity model, to be housed in a GIS, which would serve as the core for an advanced OMS. The cost/benefit analysis was completed in February 2008 (Exhibit J – Cost Benefit Analysis of OMS/GIS Initiative).

In its analysis of the GIS system, KEMA's focus was on the necessary connectivity model for the electric system to support OMS. After review of the Cost Benefit Analysis of OMS/GIS Initiative, PSE realized it needed to better understand how the implementation of GIS would impact business units across the enterprise, and that a broader analysis was necessary. PSE engaged PA Consulting to perform a Needs and Requirements Assessment of Enterprise GIS. The project was completed with an executive presentation in June 2008 (Exhibit K – Enterprise GIS – Leadership Team Presentation). At this meeting, based on PA's and KEMA's recommendations, PSE made the decision to move forward with the next phase of detailed GIS implementation planning that would provide detailed costs and benefits based on an analysis of the required technology, process, and workforce skill changes required for a successful implementation. The benefit analysis would include implementation of an OMS as one of the initial applications to leverage the value of the GIS connectivity model. For this next phase, PSE has further engaged PA Consulting to conduct the analysis. The analysis is expected to be completed fourth quarter 2008.

10.4.2 Develop end-to-end information and business process flows for outage management and emergency restoration processes. And,

10.4.3 Enhance existing technology and systems to close functionality gaps with the strategy of migrating them toward the final architecture.

PSE actions:

Process mapping will be conducted as a preliminary project step of the OMS/GIS implementation to be tasked to the implementation project team.

SCADA, Automated Meter Reading System (AMR), and CLX integration will be addressed as a part of the implementation of an OMS.

SCADA: As noted in the previous update, all of PSE's transmission substations (59 facilities) currently have SCADA and of the 281 distribution substations in PSE's system, 224 have SCADA. Thirty-two of the remaining 57 substations currently without SCADA will have SCADA installed by year end 2010 which will provide open/close SCADA status on distribution breakers in all PSE-owned distribution substations. As previously noted the remaining 25 stations are customer-leased, submarine cable stations, or are being retired over the next several years.

Distribution Automation: As noted in the Report, PSE implemented a distribution automation pilot in June 2007. The pilot included installing communications equipment to better understand communication capabilities and to evaluate data elements and control possibilities with a recloser and voltage regulator on a distribution circuit. PSE has established communication with the field device (voltage regulator and recloser) and expects the system to be functional in 2008. In addition, PSE has planned additional distribution automation pilots to further evaluate and explore various technologies over the next five years.

AMR-Cellnet: PSE has begun a project to enhance our outage outage verification functionality by taking advantage of a new messaging service being implemented by Cellnet. Once corresponding changes are made to PSE's Meter Data Warehouse (currently on-track to be completed by year-end 2008) PSE will be able to trigger an AMR outage restoration verification shortly after power has been restored to a circuit and receive restoration results for customers with AMR metering being served by the circuit within minutes. In addition, PSE is piloting an Energy Efficiency demand response project to test the two-way capabilities of a recently upgraded portion of the Cellnet system which may also improve future outage reporting and verification.

Other: In an April 2007 field exercise, PSE tested handheld electronic Personal Data Assistant (PDA) based devices for gathering and transmitting damage assessment information electronically to operating bases. PSE intends to proceed with testing of the devices on a pilot basis during actual storm events in the 2008/09 storm season.

Continued progress reports to the UTC can be expected as the company learns from the various pilots it has implemented.

10.4.4 Deploy new systems to close the functionality gaps and build out the outage management architecture.

PSE actions:

This item will be addresses through PSE's efforts for recommendation 10.4.1. and will not be addressed in future reports to the UTC.

10.4.5 Develop a phased implementation plan for outage management related information system and processes.

PSE actions:

This item will be addresses through PSE's efforts for recommendation 10.4.1. and will not be addressed in future reports to the UTC.

11.4 SUPPORT SERVICES RECOMMENDATIONS

11.4.1 Refine the Emergency/Storm Event Response Services Contract (ESERSC) to add the planning, training, communication, and evaluation roles necessary to plan for and implement major restoration efforts.

PSE actions:

As noted in the Report, PSE did not accept KEMA's recommendation to refine the ESERSC. As noted in Section 7.4.1, ultimate responsibility for storm restoration belongs to PSE—utilizing PSE, Service Provider, and additional outside contractors to assess and restore service to its customers. PSE is committed to meeting the performance metrics defined by the 24, 48, and 72 hour milestones for customer restoration communications.

During the 2007/08 storm season, PSE successfully implemented "operations conference calls" to enhance information on resource requirements and estimated restoration times. These calls are initiated by the EOC and include all operating base management from both PSE and Potelco.

For the 2008 training requirements, PSE established a work order for Potelco employees to charge any necessary storm training to and as noted above PSE and Potelco will be conducting EOC and operating base orientations and mock storm exercises prior to the 2008/09 storm season.

These steps are now a normal part of PSE's emergency preparedness process, although continued refinement is expected with the company's annual process review. This item is considered completed, and will not be addressed in future reports to the UTC.

12.4 MATERIALS MANAGEMENT AND LOGISTICS RECOMMENDATIONS

12.4.1 Enhance logistics to better support the number of crews supporting the restoration.

PSE actions:

To further support PSE implementation of KEMA's recommendation, PSE has engaged a logistics vendor, Base Logistics, to produce a written plan in accordance with PSE's CERP that establishes processes and identifies resources and services required to support internal and mutual assistance personnel (both PSE employees and PSE contracted personnel) involved in restoration operations. The plan will identify logistics roles and responsibilities and establish parameters for resource activation and event management. The plan is expected to be completed by October 2008 (Exhibit L – PSE's Base Logistics Agreement).

Continued progress reports to the UTC can be expected as the company finalizes its written plan.

12.4.2 Document material management policies and processes created to support storm levels.

PSE actions:

As noted in the Report, PSE updated its Purchasing/Materials Management's Emergency Manual to document PSE storm practices. This Manual is updated following the storm season and reviewed annually each fall prior the upcoming storm season.

These steps are now a normal part of PSE's emergency preparedness process, although continued refinement is expected with the company's annual process review. This item is considered completed, and will not be addressed in future reports to the UTC.

13.4 POST-EVENT REVIEW RECOMMENDATIONS

13.4.1 Ensure the existing post-storm actions and recommendations are consistent with the leading practice model presented in this report.

PSE actions:

In 2008 PSE assigned a project manager to oversee PSE actions in response to the master task list provided in the Report which incorporated recommendations from PSE internal storm debriefs, the Governor's After Action Review, and customer focus group and survey input. As part of PSE's GRC, PSE provided an update on these tasks through a UTC staff data request (DR 54). An additional section in this report has been included to provide more information on the status of the non-KEMA recommendations.

This item is considered completed, and will not be addressed in future reports to the UTC. However, updates will be provided on recommendations that are being pursued but are not complete or are still under consideration.

14.4 INFRASTRUCTURE CONDITIONS RECOMMENDATIONS

14.4.1 Enhance PSE's transmission vegetation management policy and standards for ROW width.

PSE actions:

Policy changes regulating vegetation management continues to be a top legislative objective for the company. PSE participated with other utilities and UTC staff in a vegetation management work group convened by Washington State Representatives Kevin Van De Wege (D-Sequim) and Dean Takko (D-Raymond) to develop policy proposals for consideration by the Legislature in the 2009 session. Following that meeting, utilities have begun working on a set of proposed changes to the law that would lessen the burden and the risk for them to manage vegetation in and adjacent to public rights-of-way. The primary policy objectives PSE will encourage include:

- Improving utility access to hazard trees in areas near utility infrastructure,
- Requiring local jurisdictions plant compatible vegetation around utility infrastructure (right tree, right place), and
- Reducing risk of damage to utility infrastructure from trees left as buffers in land development conversions.

Additionally, PSE is engaged in rulemaking processes at the Department of Community, Trade and Economic Development and the Department of Natural Resources in an effort to prioritize protection of utility infrastructure in the Washington Administrative Code and local ordinances.

PSE has engaged a consultant to evaluate PSE's existing practices for vegetation management along high voltage distribution lines, and to offer suggestions for improvements. The consultants report is expected by year-end 2008.

For 2008 PSE increased its vegetation management spending by $2 million, for a total expenditure of $12 million and will maintain this level of funding in 2009.

This item is not considered completed, and will be addressed in future reports to the UTC.

14.4.2 Aggressively develop and maintain cross-country transmission access roads.

PSE actions:

PSE noted in the Report that PSE accepted KEMA's recommendation.

PSE initiated a project to consolidate information on access point locations, and transmission pole location information in association with the company's vegetation management data collection processes. This data will be brought into a GIS application for collecting data on Right of Way (ROW) and access conditions. This application will form the basis for development of a central data repository for cross-country transmission access information. Prioritization of budgeting for access improvements will be based, among other things, on criticality of line, regularity of damage, whether the line has a secondary feed, and road construction costs and permitting considerations. Because of system configuration and loop feeds for many transmission lines, the company anticipates that it will continue to elect to use ad-hoc solutions for some cross-country transmission line access, such as specialized equipment or temporary road construction. While potentially extending restoration times, this practice is offset by elimination of the extremely high cost and permitting issues associated with building and maintaining access roads on all cross-country line.

In addition to collecting data, PSE is funding ongoing work on the maintenance of access points and access along critical cross county transmission ROWs.

This item is not considered completed, and will be addressed in future reports to the UTC.

14.4.3 Evaluate hardening opportunities for both transmission and distribution.

PSE actions:

PSE noted in the Report that PSE accepted KEMA's recommendation.

PSE has identified a number of system enhancements (Exhibit M – Potential System Hardening Strategies) that may improve the electric system's resilience to minor or major storm events. Enhancements considered include the following: Design changes to reduce overhead electric line exposure to trees and windblown limbs; reviewing the type of fuses that are installed in the field; installing switches that will allow isolation of sections of line damaged for service restoration; strengthening selected transmission line structures to reduce damage due to trees; labeling more transmission structures for ease in identifying damaged circuits in a storm; and looking at opportunities for the use of "breakaway" devices that will prevent major damage to transmission structures when the lines are struck by trees.

To analyze the benefits of these strategies, PSE engaged a consultant to review these tactics and relative costs and to identify additional techniques with cost information that should be considered in the system planning process. The consultant has completed his study and provided a roadmap for targeting reliability improvements (Exhibit N – Reliability Roadmap). While the consultants focus was on SAIDI improvements the recommendations include strategies developed for hardening the system (i.e., increased sectionalizing switches, distribution automation, etc.) which would improve system performance in storms. PSE will be incorporating these projects in its budgeting process.

PSE discussed the use of "breakaway" devices with the consultant and while there has been some use of this type of device at the service voltage level (<600V) there has been limited use at the distribution and transmission level (>10,000V). PSE is not pursuing the "breakaway" devices at this time.

Although this item is not considered completed, it is more appropriately addressed in future annual reliability reports to the UTC because of its impact on storm and non-storm system performance. As a consequence, the item will not be addressed in future storm reports to the UTC.

ADDITIONAL RECOMMENDATIONS

With the exception of items B-12, C-10, and E-27 below, these items have either been accepted and are now a normal part of PSE's emergency preparedness process, although continued refinement is expected with the company's annual process review or they have been rejected, with an explanation. We consider these items to be completed, and they will not be addressed in future reports to the UTC. Updates on the exceptions above will be provided in future annual updates.

1.1 EMERGENCY RESPONSE PLANNING AND STRUCTURE

1.1.1 Enhance Staffing

A-1—Enhance PSE employee's emergency response planning and execution capability (add 1-2 FTEs to Operations Continuity to support storm plan improvement recommendations).
PSE actions: PSE accepted this internal recommendation.
PSE identified the need to add additional support to the Operations Continuity organization and added a full time employee on April 14, 2008. This position supports the new training and process initiatives generated by the post-storm review.

A-14—Formalize role of lodging coordinators in plan.
PSE actions: PSE accepted this internal recommendation.
Purchasing developed the lodging coordinator role, conducted training and worked with Emergency Planning to staff the position. The position has responsibility to secure lodging for all personnel responding to storms (Potelco, PSE, flagging contractors, etc.). This position's duties and responsibilities are defined in the CERP.

A-20—Increase the number of trained system operators to improve switching times.
PSE actions: PSE accepted this internal recommendation.
To reduce bottlenecks in obtaining switching orders, two additional System Operators have been added. In addition, to address succession planning for System Operations, PSE has three trainees available for storm support.

1.1.2 Improve Communication Tools for System Operations and Dispatch

A-6—Stock additional radios for foreign crews at operating bases.
PSE actions: PSE accepted this internal recommendation.
Seventy-five additional radios have been dispersed to operating bases.

A-7—Increase radio frequency channels.
PSE actions: PSE accepted this internal recommendation.
Additional radio channels have been added in South King and PSE is pursuing an additional channel for Whatcom County pending Canadian approval.

A-8—Increase radio capacity.
PSE actions: PSE accepted this internal recommendation.
Additional radios and radio channels have been added to increase radio capacity.

A-9—Provide additional cell phones that will work when power supplies are out.
PSE actions: PSE accepted this internal recommendation.
There are approximately 60 spare phones stocked in the EOC on a standby status which can be activated as needed at any time.

1.1.3 Ensure Adequate Supplies

A-10—Stock adequate quantities of storm bags in operating bases.
PSE actions: PSE accepted this internal recommendation.
Additional storm bags have been stocked at operating bases and an extra 50 bags are available at Central Stores

A-11—Develop checklist for staging areas.
PSE actions: PSE accepted this internal recommendation.
A checklist for establishing staging areas was developed for inclusion in requests for proposals from logistics vendors and has been incorporated in the CERP, Volume II.

A-12—Develop checklist for foreign crew contracting (materials, equipment, etc.).
PSE actions: PSE accepted this internal recommendation.
PSE has developed a checklist covering incoming foreign crew attributes (equipment, materials, personnel, work rules, etc.) to assist in determining what PSE may need to provide and how to best utilize the crew.

A-23—Provide more circuit map books to operating bases.
PSE actions: PSE accepted this internal recommendation.
Sufficient quantities of circuit map books have been delivered to operating bases and will be restocked for the 2008/09 storm season and as needed.

A-24—Provide more PSE all-wheel drive SUVs.
PSE actions: PSE accepted this internal recommendation.
Purchasing has rental contracts in place to secure all-wheel vehicles 24/7, 365 days/year for use during storm response and recovery.

A-26—Provide PSE issued gear (hats/coats, etc.) for all employees working storm.
PSE actions: PSE has not accepted this internal recommendation.
PSE provides required safety gear (hard hats, safety glasses and vests) for emergency response efforts.

A-27—Develop plan for fueling equipment when emergencies make it difficult to get gas.
PSE actions: PSE accepted this internal recommendation.
Potelco and PSE have existing contracts with fuel providers to fuel line and service vehicles. In addition, as part of PSE's engagement of Base Logistics to develop logistical support for staging sites, information will be provided to all emergency responders on fuel availability options for PSE issued or rental vehicles by pre-identified site.

1.1.4 Increase Employee Involvement in Storm Activities

A-21—Reinforce management support for employee participation in storm restoration.
PSE actions: PSE accepted this internal recommendation.
Employees receiving their emergency response assignments receive a memo from the Senior Vice President, Operations expressing the critical role each plays in PSE's emergency response efforts. In addition, included in the new employee orientations is a discussion of emergency response assignments and expectations.

A-22—Identify and train additional qualified and skilled employees for key emergency response roles including damage assessors, crew coordinators, dispatchers, system operators, data entry, customer service representatives, and community representatives.
PSE actions: PSE accepted this internal recommendation.
PSE increased the number of trained employees for storm assignment. For 2007/08, there were 667 total storm employees, up from 550 for the previous year. For the 2008/09 storm season 758 employees have storm assignments.

1.1.5 General Recommendations

A-13—Develop plan for opening a Whidbey operating base as appropriate (staffing & triggers).
PSE actions: PSE accepted this internal recommendation.
Due to the number of 2006/07 storms impacting Whidbey Island, PSE and Potelco jointly developed a plan to open and staff the Whidbey operating base as needed to provide local area coordination when necessary.

A-25—Assemble a list of electrical contractors who can do weather head or homeowner emergency-type work in order to not leave customers without assistance on weekends or holidays in future.
PSE actions: PSE accepted this internal recommendation subject to liability concerns.
A referral list for customers is currently under development and expected to be completed prior to the upcoming storm season and available to customer call representatives subject to acceptable contractual arrangements.
A-28—For accountability, hire local people to work in their communities (do not make someone who lives in Puyallup drive to Bremerton to do damage assessment).
PSE actions: PSE accepted this customer focus group recommendation.
PSE does assign personnel to storm work close to where they live. However, additional out-of-area resources may be required depending on personnel availability and the level of storm damage. PSE does not accept the recommendation to "hire" additional temporary employees as we seek specific skills and experience for emergency response roles.

1.2 EMERGENCY RESTORATION EXECUTION

1.2.1 Improve Damage Assessment Capability

B-4—Enhance PSE DA support capability.
PSE actions: PSE accepted this internal recommendation.

In addition to annual training, support to damage assessment teams has been enhanced by acquiring GPS units, ensuring adequate storm bag supplies, and improving the availability of fleet vehicles.

B-5—Benchmark DA process best practices.
PSE actions: PSE accepted this internal recommendation.
PSE retained KEMA to assist in developing a damage assessment strategy based on historical data (system damage, weather, restoration times, etc.) to further enhance our ability to provide early restoration estimates. Additionally, KEMA was tasked with examining leading damage assessment practices in the industry in modeling storm damage and corresponding restoration time estimates.

KEMA completed its survey and provided PSE a report in May 2008 (Exhibit E - Damage Assessment Training Guide). As discussed in Section 6.4.1 of the preceding KEMA portion of this report, the results of the survey affirmed that PSE's current damage assessment practices are valid based upon the current outage technologies utilized and PSE's ongoing investigation into possible implementation of and OMS and DA Mobile tool may lead to further refinements in the DA process.

1.2.2 Teaming with Jurisdictions to Increase Efficiency

B-10—Develop strategy to increase the number of qualified flaggers available.
PSE actions: PSE accepted this internal recommendation.
Additional flagging contractors have been added and PSE has received approval for temporary state certification exemption for out-of-state flaggers traveling with foreign crews.

B-11—Pursue WA State flagging certification exemption.
PSE actions: PSE accepted this internal recommendation.
PSE has received information from the WSDOT that in the event of a Governor's Declaration of Disaster for the State, there is an exemption for the WA state flagging certification and that out of state certified flaggers may be utilized with out of state electric line crews.

B-12—Formalize "utility road clearing task force" with DOT, County/City Roads, PSE, Potelco and Asplundh.
PSE actions: PSE accepted this Governor's After Action Review recommendation.
State, county, and city agencies and utilities were encouraged to coordinate their "road clearing" activities. A plan is being actively negotiated with state and county agencies with PSE in a lead role with WSDOT for this statewide initiative.

B-13—Request HOV lane exemption from State Patrol.
PSE actions: PSE accepted this Governor's After Action Review recommendation.
HOV lane exemptions were included as part of the Washington State Memorandum of Understanding.

B-14—Work with State Emergency Management Division to obtain Governor's Declaration of Disaster.
PSE actions: PSE accepted this Governor's After Action Review recommendation.

As soon as the Governor declares a State Disaster, PSE will be notified. Copies of the disaster declaration can then be faxed to foreign crews and for expediting state border crossings. This was completed with the signing of the Memorandum of Understanding between state agencies and PSE.

1.2.3 Clearances

B-24—Investigate increasing use of self-protected clearance to relieve system operations congestion.

PSE actions: PSE accepted this internal recommendation.

A review of the practice of using self-protection clearances was completed and the revised guidelines for self-clearance use are included in CERP and operating base orientations.

B-25—Investigate using a qualified local area coordination site manager to call in clearances for multiple crews.

PSE actions: PSE accepted this internal recommendation within limitations of state law. The practice during the storm where LAC site managers facilitated clearances over larger areas of the system so multiple crews could work within this clearance was reviewed. While coordinators can facilitate clearances, crew foremen are responsible for taking clearances and monitoring their crews. It is included in the CERP and operating base orientations.

1.2.4 General Recommendations

B-6—Streamline safety orientations for foreign crews.

PSE actions: PSE accepted this internal recommendation.

A review of Potelco's safety orientation plan resulted in reinforcement of best practices utilized in the Hanukkah Eve storm: the primary orientation location is at PSE's Kent General Stores location so in addition to safety orientation crews can pick-up a pre-packaged storm material kit and when needed additional orientation locations are added to align with where the crew is coming from and the location the crew will be assigned. Through tracking the many crews who have now had the training, crews can now immediately go to work.

B-7—Expand use of GPS for crews, damage assessors, and crew coordinators.

PSE actions: PSE accepted this internal recommendation.

The use of GPS units has been expanded. Additional GPS devices were purchased and provided to operating bases.

B-8—Enhance 911 call taker training and process to triage 911 calls.

PSE actions: PSE accepted this internal recommendation.

As discussed in Section 4.4.1 the Report, 911 call takers receive annual training. Operating bases have developed processes for triaging 911 calls.

B-9—Develop plan to deploy additional helicopters for patrolling, damage assessment.

PSE actions: PSE accepted this internal recommendation.

PSE has added additional helicopter contractors, and as part of the Washington State Memorandum of Understanding, can access National Guard resources if needed.

NOTE: The Internal Debrief recommendation regarding "transmission restoration priority teams" (B-23) was included in KEMA's recommendations (7.4.2) discussed in the Report.

1.3 EXTERNAL COMMUNICATIONS

1.3.1 Proactively Engage with the Local Media

C-3—Make use of local media and enlist them as partners with a public service perspective.
PSE actions: PSE accepted this internal recommendation.
PSE's emergency Corporate Communications process includes the notification of local media sources.

C-4—Identify local media outlets in advance.
PSE actions: PSE accepted this internal recommendation.
Corporate Communications process includes the listing and notification of local media sources.

C-5—Send out electronic messages directly from the EOC to media channels.
PSE actions: PSE accepted this internal recommendation.
To provide a direct link between the EOC and external agencies and the media, an external EOC report was developed and used in the 2007/08 storm season and will be utilized in the 2008/09 season.

C-7—Proactively build pre-storm relationships with local media and elected officials.
PSE actions: PSE accepted this internal recommendation.
Local media and government agencies were contacted and the Corporate Communications process includes the listing and notification of local media sources and government agencies. Local Government and Community Relations Managers went to cities and demonstrated the PSE Outage Dashboard as a tool to aid in our preparedness communication with our government customers.

1.3.2 Provide Customers with Damage Information More Openly

C-6—Develop culture of openly presenting the picture and setting reasonable outage length estimates, especially in the larger events.
PSE actions: PSE accepted this internal recommendation.
To create storm categories and processes to establish general restoration times and expectations, on a day-to-day basis, the Corporate Communications, Customer Services and the Operations departments collaborate on external messages prior to issuing or posting information about disruption of electric or natural gas service. PSE's new storm levels serve as a guide for scaling storm response based on severity of damage, including timelines for establishing corporate and local estimated restoration times.

C-8—Provide early, broad estimates of restoration times for customers.
PSE actions: PSE accepted this internal recommendation.
PSE integrated into its new storm levels, communication intervals of 24, 48, and 72-hours, for progressively providing more detailed outage restoration information.

C-9—Provide outage dashboard presentations to cities/counties during storm event (source: CRM debriefing).
PSE actions: PSE accepted this internal recommendation.
PSE's Community Relations Managers (CRMs) were provided wireless access for their personal laptops and training on the Outage Dashboard in the fall of 2007. On request by the jurisdictions, they will share information from the outage dashboard online and/or make screen prints of area specific information.

C-10—Continually update the map on the PSE Web site showing the progress of work crews.
PSE actions: PSE has taken this customer focus group recommendation under consideration.
The Service Alert Map is to be completed prior to the 2008/09 storm season with damage location and information. Crew location data may occur in future development of technology.

C-11—Provide a Web-accessible tool for customers to enter an address to get the latest news.
PSE actions: PSE has not accepted this customer focus group recommendation.
This is not being planned at this time as there are customer data security and privacy issues with accessing outage information at address level. The new Service Alert Map tool is expected to provide restoration information at area (e.g., zip code) level.

C-12—Provide ability for customers to send damage information to PSE.
PSE actions: PSE has taken this customer focus group recommendation under consideration.
Customers are currently able to send damage information to customercare@pse.com. Additional capability is being considered in the development of the Service Alert Map display, as part of future Web-based transaction enhancements, and as part of a possible OMS implementation.

C-13—Help build community networks to disseminate information through fire stations or put up signs in neighborhoods.
PSE actions: PSE partially accepts this customer focus group recommendation.
While PSE does not have sufficient staff to post information at individual fire stations and neighborhoods, PSE CRMs maintain communications with a network of counties, municipalities and neighborhood associations throughout the year and during emergency events. Additional information can be provided through PSE's plan to man County EOCs when requested. In addition, PSE coordinates with the Red Cross during storm events on-site locations and providing information to customers. PSE also supports the Red Cross through the Puget Sound Energy Foundation.

C-15—Inform customers what substation they depend on and use so that speaking through the media will be an efficient way of communicating which areas are up and timelines for others.
PSE actions: PSE has not accepted this customer focus group recommendation.
Substation level outage information is not a reliable source for estimated restore times as there may be many different outage causes for a given substation (circuits, laterals,

etc.). PSE will be providing area updates through the IVRU and media at the city and neighborhood levels.

C-18—Provide outage information and estimated restore times from day 1 in local areas.
PSE actions: PSE accepted this customer focus group recommendation.
PSE has developed a storm level chart in the CERP that provides guidelines (timelines and granularity) on what estimates PSE can reasonably provide.

C-21—Establish times that PSE representative(s) will be on local radio shows to take call-in questions.
PSE actions: Not accepted due to practical reasons (e.g. how to choose which radio station) but make representatives available on request.
For example, during the December 2006 Hanukkah Eve storm, PSE was constantly on the call-in shows, particularly KOMO-Radio's neighborhood-to-neighborhood 24-hour call-in; Northwest Cable News' call-in, as well as the talk-show programs on KIRO and KPLU radio stations. In addition, PSE participated in many "livers" where the TV anchors provided viewers with updates and spoke live to PSE representatives via phone.

1.3.3 General Recommendations

C-14—Develop a "winter storm warning" best tips magnet for customers to put on refrigerators.
PSE actions: PSE accepted this customer focus group recommendation.
PSE prepared a wallet card and included it with its bill package November 2007. PSE will be including a section on winter preparation tips in its 2008 EnergyWise newsletter.

C-16—Assist in setting up local shelters.
PSE actions: PSE accepted this customer focus group recommendation.
PSE will support and assist as resources and requests allow.

C-20—Supply PSE brochures on weather heads and storm restoration flyers in crew trucks.
PSE actions: PSE accepted this internal recommendation.
PSE has customer information about weather head damage on door hangers and will make them available to operating bases, storm bags and service trucks. Storm restoration flyers will also be provided to Crew Coordinator to improve their ability to communicate with customers.

NOTE: The Governor's After Action Review recommendation regarding staffing state and county EOCs (C-2) was included in KEMA's recommendations (4.4.1). The customer focus group recommendation to use local radio for communication (C-17) and to post flyers in police and fire stations (C-19) were addressed by similar visioning (C-3) and customer focus group (C-13) recommendation respectively.

1.4 CUSTOMER SERVICE

1.4.1 Increase Call Taking Capacity

D-4—Increase PSE call taking capacity for varying magnitude of storms.

PSE actions: PSE accepted this internal recommendation.
Call taking capability has been increased through the use of additional representatives at construction offices, 30 additional remote/at home representatives, and the annual identification and training of non-call center call takers. Also, the messaging structure by community is in place for customers to hear updates without talking to a representative or having to hold for long periods. The message structure application will be on PSE's IVRU menu option as well as the Qwest IVRU, further discussed in 9.4.2, which has virtually unlimited trunk phone line capacity.

D-7—Expand call handling to better accommodate requests for specific information and to more fully collect customer comments.
PSE actions: PSE accepted this customer focus group recommendation.
See comments above.

1.4.2 Improve Call System Functionality

D-5—Develop a system that calls customer numbers with updates on a daily basis.
PSE actions: PSE has taken this customer focus group recommendation under consideration.
As technology and information improves through the potential implementation of an OMS system, PSE will consider implementing.

D-6—Provide an automated call number to put in your phone number to get a progress report and or a nightly call back.
PSE actions: PSE has taken this customer focus group recommendation under consideration.
As noted above, as technology and information improves through the potential implementation of an OMS system, PSE will consider implementing.

D-10—Train most employees as reserves to help call center in disaster so they are prepared in advance of storm.
PSE actions: PSE accepted this customer focus group recommendation.
PSE has identified and notified 200 employees for call center duty. PSE developed a web based outage entry tool that simplifies entry and requires minimal training.

D-11—At beginning of phone tree, begin by asking if a customer needs to immediately speak with a representative to press zero now (before long phone message).
PSE actions: PSE has not accepted this customer focus group recommendation.
PSE is focusing on providing community information both via the phone system and www.PSE.com within 24 to 72 hours depending on size of storm. The messaging will allow nearly unlimited access by customers. Representatives are limited and letting customers bypass messaging would result in long waits during peak periods. Customers would also miss valuable messaging being provided through the IVRU. For additional access, customers can write to customercare@pse.com.

D-12—Provide a voice mail option so you do not have to wait on hold and can get a call back in two hours.
PSE actions: PSE has not accepted this customer focus group recommendation.

As noted above, PSE is focused on providing valuable information through its IVRU. Also, due to limited representatives, PSE may not be able to provide timely call backs in a large event and further frustrate customers.

1.4.3 General Recommendations

D-8—Figure out a way to "deputize" the public to help (i.e., cut trees, etc.) for true community partnership.
PSE actions: PSE has not accepted this customer focus group recommendation. PSE is working with the State Department of Transportation and other jurisdictional public works and roads personnel to complete the Utility Road Clearing Task Force plan. This plan will coordinate the efforts of qualified tree crews, line crews and roads crews. For public safety reasons, PSE is not adopting this recommendation.

D-9—Cut rates or reimburse the public for inconvenience because PSE would not give restoration times.
PSE actions: PSE has not accepted this customer focus group recommendation. Rates are set and approved by the UTC.

D-13—Offer low-cost financing for generator operation and maintenance.
PSE actions: PSE has not accepted this customer focus group recommendation. PSE has provided limited technical support and information to its customers on "standby" generator issues for many years. These services are available to residential and commercial customers. The PSE Energy Advisors are able to discuss general information and, if necessary, PSE has a specific staff person who is proficient in most aspects of this product and market. At the current time, PSE believes it can best serve its customers by providing this level of information and support and not act as a retailer of products or presenting financing options.

D-14—State on the call center line the state where the call center is located.
PSE actions: PSE has not accepted this customer focus group recommendation. While it is possible, PSE questions the need, and the repetitiveness, should a customer call more than once. PSE's call center is located within PSE's service area.

NOTE: The Visioning recommendation regarding formalizing the escalated call process was included in KEMA's recommendations (9.4.1).

1.5 EMERGENCY RESPONSE—INFORMATION SYSTEMS

E-22—Develop an automated Emergency Operations Center report with real-time data.
PSE actions: PSE has not accepted this internal recommendation.
Real time CLX and AMR data is currently available through the Intranet Outage Dashboard. Other data on the EOC report (crews, crew jobs, substations off-line, etc.) is not currently available on a real-time basis. Expanded dashboard capabilities will be considered in a possible OMS implementation.

E-23—Develop capability to translate outage data into relevant information for customers.
PSE actions: PSE accepted this internal recommendation.

This task is addressed through KEMA Task C-1. PSE's Corporate Communications department manages a communication process scalable to the three storm event levels. Corporate Communications collaborates with the Operations and Customer Services teams on the development of messages about PSE's readiness to respond to possible damage or the extent of disrupted service and estimated restoration times.

E-25—Develop ability to flag key or critical service customers.
PSE actions: PSE has taken this internal recommendation under consideration.
PSE's current geospatial technology is limited in its ability to provide relevant outage information for mapped customers. This capability may be evaluated should PSE pursue an OMS.

E-26—Document, track, prioritize and schedule service orders for secondary lines.
PSE actions: PSE accepted this internal recommendation.
PSE has a process for documenting and tracking service orders for secondary lines. PSE dispatchers handle the prioritization and scheduling of work dependant on the resources available. Training on the process is provided in CLX training.

E-27—Incorporate damage assessment and repair information into a system that would assist with material acquisition and dispersion.
PSE actions: PSE accepted this internal recommendation.
On a pilot basis, PSE is testing a handheld electronic Personal Data Assistant (PDA) based device that would allow gathering and transmitting damage assessment information (including pictures, GPS coordinates, and material needs) electronically to operating bases. PSE completed a non-storm field trial with 10 PDA devices at Pierce operating base in April 2008. Further tests will be conducted during the 2008/09 storm season. Larger scale deployment is dependent on technology compatibility and reliability, as well as results of further tests.

E-28—Implement a system to document, track, and prioritize 911 calls for improved response time.
PSE actions: PSE accepted this internal recommendation.
A process has been developed to provide 911 call information to operating bases for triage.

E-29—Provide simplified screens for infrequent users of the emergency response tools.
PSE actions: PSE accepted this internal recommendation.
The simplified web-based CLX interface has been developed and is in production mode.

E-30—Allow electronic entry when reenergizing a line and completing the job.
PSE actions: PSE has taken this internal recommendation under consideration.
PSE's current technology does not support automatic updating between EMS and CLX. This capability may be evaluated should PSE pursue an OMS.

E-32—Use interactive video feed from Damage Assessors in the field to report specific damage.
PSE actions: PSE has not accepted this internal recommendation.
The handheld electronic PDA DA tool described in 10.4.3 and E-27 above and cellphones having photo capability, when combined with the DA forms, provide sufficiently specific damage information.

NOTE: A number of the Visioning recommendations regarding OMS, AMR, SCADA, and improved technologies (E-15 to E-21 and E-24 and 31) were addressed through KEMA (10.4.3 and 10.4.4) or other Visioning (E-27).

1.6 LOGISTICS AND SUPPORT SERVICES

G-13—Develop plan for resourcing local area coordination centers (trailers, tents, heat, PCs, light, etc.).
PSE actions: PSE accepted this internal recommendation.
PSE has contracted with Base Logistics to provide resourcing plans for LACs and crew assembly areas. Section 7.4.2 provides further discussion on this item.

1.7 INFRASTRUCTURE CONDITIONS

H-19—Locate transmission lines underground.
PSE actions: PSE has not accepted this customer focus group recommendation.
Undergrounding transmission lines solely for reliability purposes is cost-prohibitive. As KEMA noted in their report (Section 14.3.6), undergrounding transmission lines can cost $10-20 million per circuit mile not taking into account difficult permitting and environmental issues.

NOTE: The customer focus group recommendation regarding increasing tree trimming (H-20) was included in KEMA's recommendations (14.4.1).

SPECIFIC UTC STAFF CONCERNS

In addition to updating PSE activities on the KEMA and supplemental recommendations, this report is intended to address those items identified by UTC staff in its GRC testimony on pages 19-21 of Exhibit No. (DEK-1TC), and Exhibit No._(DEK-3). These items are addressed by providing the location in this report where the item is covered, unless otherwise noted:

1. Evaluation work done by PSE or on its behalf to determine the overall cost effectiveness and benefits of implementing an OMS with an associated enterprise-wide GIS. The report must include a detailed description of the cost/benefit analyses PSE is doing or is having done, what quantitative and/or qualitative results would convince PSE to move forward with the OMS/GIS, and what timeline it proposes for implementation assuming the internal hurdle is met.

   Section 10.4.1 addresses PSE's progress on KEMA's OMS/GIS recommendation.

2. PSE's assignment of damage assessor and other resources to the emergency event, including training and processes.

   Sections 4.4.1 and 6.4.1 address DA assignments and training.

3. PSE's expectations and metrics for all parties in storm roles.

   Sections 7.4.1 and 11.4.1 address PSE storm responsibilities and our 24, 48, and 72 hour expectations (metric).

4. PSE communication of restoration information to customers no later than 72 hours after initial storm impact.

   The last paragraph of Section 5.4.1 addresses PSE communication targets.

5. PSE's communication with the UTC during a storm event through an initial report within 24 hours after initial storm impact and through regular status reports from PSE's EOC.

   The UTC has been added to the company's EOC distribution list to receive the PSE external EOC Update which is part of PSE's External Communications plan discussed in Section 8.4.1. The external EOC Update advises parties as to when the company has opened its EOC and an Update is distributed several times a day, during Level 2 and 3 events.

6. PSE's actions with respect to local area coordination planning.

   Section 7.4.2 addresses PSE actions regarding its local area coordination plans and it intention to coordinate activities with local jurisdictions.

7. PSE's emergency response process for its Bothell Emergency Center.

   Section 9.4.1 provides information on the BEC Duties and Responsibilities.

8. PSE's actions to address recommendations from the company's 2006 internal storm debrief sessions.

   The section titled "Additional Recommendations" includes an update on the various external and internal recommendations and their status, (e.g., which items have been rejected, implemented or are in the process of being implemented).

9. PSE involvement on legislative and regulatory solutions to vegetation management and infrastructure rights-of-way.

   Section 14.4.1 addresses PSE's current activity in a work group including UTC Staff.

EXHIBIT A

11/29/07 PSE Response to KEMA Report


Photo courtesy of Seattle Times, Steve Ringman

Windstorm of Dec. 14-15, 2006

KEMA recommendations and subsequent actions taken by Puget Sound Energy

PSE ACTION

PUGET SOUND ENERGY

KEMA after-action review of December 14 - 15, 2006 windstorm *"Hanukkah Eve Windstorm of 2006"*

KEMA recommendations and subsequent actions taken by PSE

Dated November 28, 2007

EMERGENCY RESTORATION – ANNUAL PLANNING

4.4 RECOMMENDATIONS

4.4.1 Expand the company emergency response capability through enhanced personnel utilization.

Puget Sound Energy (PSE) actions:

PSE accepted KEMA's recommendations.

KEMA highlighted the value of on-going training initiatives, particularly in the area of damage assessment. KEMA noted the importance of knowledge transfer in anticipation of future retirements. KEMA also acknowledged the success of the PSE liaison role utilized at the King County Emergency Coordination Center during the December 2006 windstorm and recommended that PSE apply this model to other jurisdictions.

During the period June through October 2007, 667 of PSE's 2,400 employees were provided emergency response assignments for storm activations (see Exhibit 4.4.1-A for sample of 2007 assignment letter to employees). Employees assigned to the following roles were offered opportunities to participate in training or storm planning orientations: (those assigned "damage assessor" as their primary role were required to participate in training)

- Damage Assessors
- Contract Crew Coordinators
- Drivers
- 911 Call Takers
- CLX Specialists
- Lodging Coordinators

- Emergency Operations Center (EOC) Team Members
- Back-up Dispatchers
- EOC Liaisons

A total of 498 PSE employees participated in training or storm planning orientations, representing 75% of those with 2007-08 emergency response assignments. PSE is following up with the 25% who did not participate to ensure their understanding of new processes in place for the 2007-08 storm season. This is done through one-on-one meetings or presentations at staff meetings.

Ninety percent (87 of 96) of the assigned damage assessors participated in the required Damage Assessment training. PSE's emergency planning manager is following up with 9 individuals who did not participate in 2007 to determine what training is needed for them or whether they should remain assigned to damage assessment. The follow-up will be completed by year-end 2007.

For comparison, in 2006, an estimated 550 employees received emergency response assignments; however only 223 (40%) participated in training.

PSE maintains an "emergency response" assignment database which includes employee name, title, work location, home city, contact numbers (home, work, cell), emergency response assignment and assignment location if applicable. This database is updated annually with new hires, job changes, terminations, and contact information.

Personnel with roles in operating bases and the EOC participated in a 1.5 hour orientation on storm plan processes for the 2007-08 year. Those in attendance at the operating base orientations included Potelco operations base managers, storm board coordinators, and damage assessment coordinators, PSE first response supervisors and dispatchers. Attending the EOC orientations included those assigned as EOC Directors, EOC Managers, CLX Data Specialists, Administrative Support, 911 Call Takers, EMS Analysts, Media Liaisons, Major Account Representatives, and Resource Coordinators. A total of 88 employees participated in the EOC orientations of the 102 individuals assigned to those roles, (Exhibit 4.4.1-B1 and B2). All but four of the team members on duty every fifth week attended. The five who missed the orientations will be followed up with individually by year end 2007. Some of these same individuals participated in a mock storm exercise held September 5, 2007.

Training and orientation as well as a storm/emergency drill will be repeated annually for those assigned emergency response roles. It is PSE's goal to have 100% participation in storm training or orientations in 2008 by providing a training schedule with multiple options for participation, including several make-up sessions.

On October 3, 2007, 46 PSE and Potelco operations leadership personnel participated in a 3-hour discussion on KEMA recommendations and actions taken by PSE in preparation for the 2007-08 storm season. The meeting began with a presentation by the National Weather Service on the winter forecast. Participants in the meeting included PSE and Potelco vice presidents and directors, Potelco operations managers, PSE electric first response manager and supervisors, system operations manager and supervisors, corporate communications managers, customer access center director, and EOC directors and managers. Two consultants from KEMA were also present in the session. The meeting included a discussion of leadership and management expectations, roles and responsibilities, and expected outcomes for the storm season (see Exhibit 4.4.1-C).

PSE developed and incorporated into the 2007-08 plans a new emergency response role titled "EOC Liaison." Employees assigned as EOC liaisons will report to the state or county emergency operations centers on request of the jurisdiction, and will act as the PSE liaison during the emergency event. This was modeled after the King County EOC/PSE liaison role instituted during the December 2006 windstorm (Exhibit 4.4.1-D).

PSE hosted "pre-winter storm" meetings with seven county emergency management agencies. Topics included information on lessons learned from the December windstorm, actions taken following some of the KEMA recommendations and the Governor's after action review, internal debriefs, and customer feedback. Meetings were held in Whatcom, Skagit, Island, King, Pierce, Thurston and Kitsap Counties during September and October 2007.

PSE also held several community meetings with city councils and service clubs to discuss storm preparedness.

Finally, to assure knowledge transfer in anticipation of employee retirements over the next decade, PSE is teaming less experienced and tenured engineering personnel with more experienced damage assessors and contract crew coordinators as their drivers. Prior to storm season, a team of PSE and Potelco operations and engineering managers review and update the lists of employees assigned to these roles and identify those with extensive experience in storm response, and those with less experience. This categorization is based on an employee's tenure with PSE and/or Potelco, operations (line) field experience, and storm experience. During an event, when an operating base requests additional teams of damage assessors or crew coordinators from the PSE EOC, resource coordinators work from the lists previously established.

PSE and Potelco have identified 2-3 individuals with the skills and experience required for each of the emergency response assignments at the operating bases, providing depth and opportunity for training and experience. PSE and Potelco will also augment less experienced storm base management personnel with those with extended experience at each location.

EMERGENCY RESTORATION – IMMINENT EVENT PLAN

5.4 RECOMMENDATIONS

5.4.1 Develop a storm categorization methodology and tailor aspects of the Company Emergency Response Plan (CERP) to the various levels of storms.

PSE actions:
PSE accepted KEMA's recommendation.

KEMA observed that PSE did not utilize storm categories to develop emergency response plans. Using industry leading practices, KEMA noted that PSE's Corporate Emergency Response Plan (CERP) worked well for small and mid-sized storms, but was overwhelmed by the severity of the December 14 event. KEMA recommended the creation of storm categories, as well as processes to establish general restoration times using past storm data and historical knowledge.

In response to this recommendation, PSE developed and implemented the emergency event levels shown below (to be used for both electric and natural gas events) (Exhibit 5.4.1-A):

Levels	Electric Criteria	Gas Criteria	Level of Response
Level 0 - Normal	Nominal conditions across system	Nominal conditions across system	Normal daily response activity.
Level 1 - Regional	Event localized to individual geographic areas; resources within region adequate for response.	Localized event managed with regional resources	Operations base(s) open; coordination with system operations or gas control. Gas Planning Strategy Center open for gas emergencies.
Level 2 - Significant	Multiple regions affected; requires resources from other PSE regions and/or outside PSE service territory.	Multiple regions affected; requires resources to be allocated to other PSE regions.	EOC open; multiple operating bases and may activate local area coordination. Employees with emergency response assignments mobilized.
[redacted]	Most or all regions affected; maximum level response required; need extensive resources from outside area.	Most or all regions affected; may request operator qualified resources from outside PSE.	EOC open; most or all operating bases open; external logistics support may be employed; full corporate response to support restoration efforts

The CERP will incorporate the three emergency event levels and will scale response activities accordingly. The CERP plan update is expected to be completed by year-end 2007.

Departments such as Operations, Customer Service and Corporate Communications are already using the above matrix to drive departmental specific response actions. Example follows for Operations:

Levels	Operations Actions
Level 0 - Normal	Normal operations.
Level 1 – Regional	EOC not opened Internal resources utilized Some use of employees with ER assignments
Level 2 – Significant	EOC opened. Additional contractor resources needed; some from bordering states. Moderate to extensive use of employees with ER assignments Windshield assessment utilized Complete assessment within 24-36 hrs. Local Area Coordination possible.
[illegible]	EOC opened. Resources obtained from outside of region. Full utilization of employees with ER assignments. Local area coordination implemented. Windshield assessment utilized; complete assessment within 48-72 hrs.

EMERGENCY RESTORATION – EVENT ASSESSMENT

6.4 RECOMMENDATIONS

6.4.1 Enhance the damage assessment capability and process to provide better and faster estimates of restoration times and resource requirements.

PSE actions:
PSE accepted KEMA's recommendation.

KEMA pointed out in their report that PSE's assessment process could be better supported by acquiring technology and by increasing the number of trained damage assessors.

PSE sees damage assessment and technology as separate recommendations. For actions taken by PSE related to technology in this context, refer to 10.4.3.

PSE increased the number of damage assessors from 79 in 2006 to 179 in 2007. PSE has a total of 96 employees with "Damage Assessor" as their primary role in storm response and another 83 employees with damage assessment as their secondary role. Sign in rosters for the damage assessment training reflect 193 participated in training, indicating that some employees who have other emergency response assignments also participated, even though this was not their primary or secondary emergency response role.

PSE and Potelco operations and engineering management identified employees in both organizations with the skills and experience required to be qualified damage assessors (DAs). Those with more experience and skills were identified as "A" DAs. These are employees who work with the electrical system in a technical manner on a daily basis. Those with less experience were identified as "B" DAs. PSE and Potelco team an A and B member for storm response. This will enable PSE to provide additional experience and develop the skill set for the "B" DAs to prepare them to be our future "A" team DAs. PSE DAs total 179 and Potelco DAs total 38. Of those totals, there are 115 "A" and 102 "B" assessors identified at PSE and Potelco combined.

PSE "A" and "B" DAs were required to participate in a four-hour training program that was significantly enhanced from previous years (Exhibit 6.4.1-A). The training added skills testing and practical experience in the classroom developed by a team of standards employees well skilled in damage assessment, line construction standards, safety, etc. Training also included basic safety, materials identification, navigating circuit and Thomas Brothers maps to pinpoint locations of system damage, and practice completing new DA forms to be used in storm response. The forms completed by the DAs include estimated manpower requirements and provide detailed damage descriptions for the operating base "Damage Assessment Coordinator" to use in preparing crew assignments.

PSE held seven regional "Storm Base Orientations" with Potelco and PSE employees with emergency response roles in the operating bases. At these orientations, process changes for storm response were reviewed in detail, including the commitment to have a "windshield" assessment of damage across the system within 24 hours or less; and general area restoration information within 48-72 hours of the event, depending on the severity of the emergency event (same as Exhibit for 4.4.1-B1).

This new process was tested in the first storm of the 2007-08 season on October 18, 2007. PSE was able to assess system damage, communicate estimated restoration times, and restore service in impacted areas in less than 24 hours.

KEMA was retained by PSE through year-end 2007 to assist in developing a damage assessment strategy based on historical data (system damage, weather, restoration times, etc.) to further enhance our ability to provide early restoration estimates. Any additional improvements resulting from this work will be implemented during the 2008-09 storm season. The internal PSE team working with KEMA on this strategy is examining leading practices in the industry in modeling storm damage and corresponding restoration time estimates.

EMERGENCY RESTORATION – EXECUTION

7.4 RECOMMENDATIONS

7.4.1 Institute consistent accountability for executing the storm plan.

PSE actions:
PSE believes that the appropriate level of accountability currently exists and that no changes in contracts or operating base management processes are necessary at this time. PSE acknowledges the need for ongoing reinforcement of leadership expectations and role clarification for both PSE and Potelco personnel. This will be accomplished through annual storm plan orientations, event debriefings and training efforts as described in 4.4.1 and 6.5.1.

In our discussions with KEMA, the strong role played by our service provider, Potelco, in emergency restoration and plan execution was acknowledged. KEMA noted in their interviews with PSE and Potelco operations management that certain parties viewed the CERP as bureaucratic. As noted in 6.4.1, PSE held "Storm Base Orientation" meetings in all regions with Potelco and PSE employees with operating base emergency response roles, and also held three EOC orientations for EOC team members. Expectations were communicated and roles and responsibilities were clarified as documented in the existing CERP (Exhibits 7.4.1-A and B).

7.4.2 Formalize local area coordination and transmission restoration priority activities.

PSE actions:
PSE accepted KEMA's recommendation.

KEMA recommended that PSE formalize the establishment of local area coordination sites. This proved to be an effective operating model for restoration and provided a community presence during the December 2006 windstorm. In addition, KEMA found that PSE's initiation of a transmission restoration team to coordinate transmission and substation outages was extremely effective and should be considered an option whenever transmission lines sustain significant damage.

While PSE has utilized the model of establishing "mini" storm bases or "local area coordination sites" in the past several years, formalization of this process is appropriate. PSE developed a Local Area Coordination (LAC) Plan document dated October 10, 2007 (see Exhibit 7.4.2-A) that has been incorporated into operating base and EOC resource materials. The document outlines the role of the operating base and EOC in considering when and where to open LAC sites, site staffing plans and role descriptions and includes appendices with lists of pre-identified sites, staffing, and logistics checklists.

System Operations developed, in support of the LAC Plan, Local Area Coordination Clearance Procedures (Exhibit 7.4.2-B). These procedures will assist in reducing the radio and phone traffic into System Operations causing delays for line crews waiting for switching and clearance orders.

PSE documented the establishment of the Transmission Restoration Team. The plan document (see Exhibit 7.4.2-C) formalizes a process to centralize and prioritize transmission restoration when major damage of PSE's transmission system has occurred. This plan covers the restoration of PSE's 115kV and 230kV high voltage transmission lines.

EMERGENCY RESTORATION – EXTERNAL COMMUNICATIONS

8.4 RECOMMENDATIONS

8.4.1 Create an integrated corporate and local communication strategy that is scalable to storm severity.

PSE actions:
PSE accepted KEMA's recommendation.

Customers and the public, in general, expect Puget Sound Energy to inform them when a power outage or natural gas emergency occurs. Delivering timely, accurate and consistent information is key to meeting customer and community expectations.

Regardless of the level of the storm event, communication with customers and the media goes 'live' each day with even the smallest events. On a day-to-day basis, the Corporate Communications, Customer Services and the Operations departments collaborate on external messages prior to issuing or posting information about disruption of electric or natural gas service.

This tag-team approach ensures accuracy and consistency and accuracy of information provided to customers by way of various communications channels, including:

- A brief recorded message about the disrupted service all customers hear upon calling PSE
- Reports to the news media
- Key messages PSE's government and community relations managers provide local jurisdictions and emergency management agencies
- Web information posted to www.PSE.com, if the disruption of electric or natural gas service affects a significant number of customers (e.g., a Level 2 "Significant" event) (Exhibit 8.4.1-A)

KEMA's discussions with PSE focused on a communications strategy that scales to various levels of storm response and the need for different messages and delivery across the service territory.

PSE's Corporate Communications department manages a communication process scaleable to the three storm event levels (referenced in 5.4.1 above).

Based on weather forecasts predicting a wind storm at least 24 to 48 hours prior to reaching PSE's service territory, PSE's Corporate Communications team collaborates with the Operations and Customer Services teams on development of messages about PSE's readiness to respond to possible damage caused by the weather system, and tips for citizens. These messages, through a news release and/or interviews with news reporters are delivered to the media and key government and social service agencies (Exhibit 8.4.1-B). In the case of a predicted major wind storm, PSE collaborates with the National Weather Service and local utilities on the development of the messages to ensure consistency throughout Western Washington (Exhibit 8.4.1-C and D).

Once the storm hits, PSE's process is as follows:

Level 1

1. Designated Corporate Communications team member (hereinafter "team member") gathers information from the utility's Operations team about the extent of disrupted service and estimated restoration times and reviews intended message to be provided to customers via Customer Services, the media and local community outreach.
2. Team member develops message and provides to the Customer Service (Access Center) 24-hour point desk or customer communications program manager for recording on phone line.
3. Team member delivers the same message to the media and the local Government and Community Relations team members in areas affected by the event. As the utility's Operations team (primarily the System Manager) provides the Corporate Communications team member with updates about the restoration effort, the team member goes through steps 1-3 to ensure timely and consistent distribution of new information.

[redacted]

1. At least 24 hours prior to the prediction of a significant weather system reaching PSE's service territory, and in response to an employee alert issued by Operations, the Corporate Communications, Operations, Customer Services and Government and Community Relations teams collaborate on 'readiness' messages to provide customers, the media, communities, key agencies, and others, and to post on PSE.com in advance of possible service disruption.
2. Operations notifies Corporate Communications about opening of regional storm operating bases as well as the PSE Emergency Operations Center (EOC). A Corporate Communications team member reports to the EOC (hereinafter EOC communications representative) to develop corporate-wide information and messages about the extent of the damage to the energy system, estimated number of customers whose service is disrupted and process for estimating time of restoration.
3. Approximately every four hours, the EOC holds a conference call for updated reports from the field, Customer Access Center, Government and Community Relations and Corporate Communications representatives. Immediately after the conference call, these members stay on the line to develop consistent messages.

Based on information from the conference call, the EOC communications representative develops an updated message and reviews it with the Director on-duty in the EOC. The updated message is distributed companywide and used for:

- Updating the recorded phone message for customers
- Communicating to appropriate local and state agencies
- Reporting to the news media every four hours timed to radio and television broadcast times (media advisories distributed on wire services and/or phone contact, with first call made to the Associated Press) 5 a.m., 9 a.m., 1 p.m., 5 p.m., 9 p.m., 1 a.m., and in response to inquiries on the company's 24-hour media line, which is picked up live during storms and regular business hours and alerts a news representative who responds immediately.
- Posting to "Service Alert" on PSE.com home page, which includes an updated outage map

4. In the event a small number of power outages still exist in a specific geographical region when the EOC closes, the Corporate Communications team continues to collaborate with the Operations, Customer Services and Government and Community Relations team members on development and distribution of the message (as listed in Step 3).

EMERGENCY RESTORATION – CUSTOMER SERVICE

9.4 RECOMMENDATIONS

9.4.1 Formalize a customer escalated call process.

PSE actions:

PSE accepted KEMA's recommendation.

PSE formalized the process for managing escalated calls. A "communications lead" role in each operating base is being developed. The position will serve as a central point of contact for specific customer information. The employees serving as operation base communication leads will be individuals with past storm room experience, and possess the skills to find the information for specific customers without disrupting operations management who are focused on restoration. PSE will have the list of qualified employees identified for this role and orientation completed by the 2008-09 storm season. PSE will, however, fill the role on an ad hoc basis for storms in this season as needed.

Logistics to support the process include the establishment of the Bothell Emergency Center (BEC), and the identification of qualified staff for PSE corporate headquarters. Officers of PSE have been provided emergency response roles for "Major" events, including a group of officers identified to support escalated calls. The matrix below summarizes the actions of Customer Service, Corporate Communications, Government and Community Relations for handling escalated calls (Exhibit 9.4.1-A):

Levels	Electric Criteria	Level of Response	Customer Service, Corporate Communications, Community and Government Relations Actions
Level 0 - Normal	Nominal conditions across system Event localized to individual geographic areas; resources within region adequate for response.	Normal daily response activity.	Areas work with System Operations leadership to manage customer issues or needs
Level 1 - Regional	Multiple regions affected; requires resources from other PSE regions and/or outside PSE service territory.	Operations base(s) open; coordination with system operations or gas control. Gas Planning Strategy Center open for gas emergencies	Operating bases will assign a "communications lead" as required to be a central point of contact for customer or community information These individuals have past storm room experience, and the ability to find the information without disturbing storm base operations management who are focused on restoration. Logistics to support the process include the establishment of the Bothell Emergency Center (PSE's Call Center) with a formal escalation process and specifically trained personnel on point to manage customer calls, and the identification of qualified staff for PSE corporate headquarters. PSE's major and business account customer representatives work out of the EOC and gather information from System Operations.
Level 2 - Significant	Most or all regions affected; maximum level response required; need extensive resources from outside area	EOC open; multiple operating bases and may activate local area coordination Employees with emergency response assignments mobilized.	(Same as above)
	Nominal conditions across system	EOC open; most or all operating bases open; external logistics support may be employed; full corporate response to support restoration efforts.	Operating bases will assign a "communications lead" as required to be a central point of contact for customer or community information. Depending on the volume of escalation in a major event, Base Operations may provide a point person in the Call Center to assist with information gathering. Officers of PSE have been provided emergency response roles for "major" events, including a group identified to support escalated calls at the Call Center PSE's Industrial, major business customer and school/hospitals account representatives work out of the EOC and gather information from System Operations.

9.4.2 Use local carrier phone network in front of CLX/IVRU to enhance call-taking capacity and capabilities.

PSE actions:
PSE accepted KEMA's recommendation in concept with implementation in two phases.

Phase I will be implemented for emergency events when community messaging is necessary. The plan is to use Qwest's (local carrier) EZ Route VRU in conjunction with PSE's VRU to overflow callers to a recorded message with information specific to their community, possibly using zip codes to channel information. If requested, customers will have the opportunity to be re-routed back to PSE if they wish to speak to a live representative. A requirements document is in the process of being developed and the goal for implementation of Phase I is end of January 2008.

Phase II is more complicated as it requires data interface and integration between CLX (PSE's customer information system) and Qwest to allow customers calling into the Qwest system to be recognized by their phone number. Requirements gathering, cost/benefit analysis and a project scope will commence in 2008.

EMERGENCY RESTORATION – INFORMATION SYSTEMS AND PROCESSES

10.4 RECOMMENDATIONS

10.4.1 Establish enterprise-level technology, data and integration architecture for outage management related processes.

PSE actions:
PSE is considering KEMA's recommendation.

KEMA found that while PSE's information systems provide adequate outage response functionality and performance for typical storms, those systems were overwhelmed in the December 2006 event by an extreme volume of data. Additionally, manual data input could not maintain pace, resulting in PSE's information systems being inadequate to support the level of outage response required. When comparing PSE's information systems to those used by leading practice organizations, KEMA observed that PSE's systems for outage response are limited in functionality and heavily reliant upon on manual operations.

KEMA noted that that PSE does not utilize a dedicated Outage Management System (OMS) or a system connectivity model – usually contained within in a Geographic Information System (GIS). Additionally, integration between PSE's current outage response tool, ConsumerLinX (CLX) and several external systems, including Advanced Metering Infrastructure (AMI), Energy Management System (EMS) and Distribution Data Display (DDD) is limited.

Leveraging the results of studies completed by KEMA for its after action review, PSE has contracted with KEMA to further define what a new, enterprise-level architecture for integrating technology and data for outage management might require and cost. The roadmap includes defining a new system connectivity model, to be housed in a Geographic Information System (GIS), which would serve as the core for an advanced Outage Management System (OMS). The cost/benefit analysis is expected to be completed by first quarter 2008. For PSE's 21,000 distribution mile service territory, cost may be significantly higher than that for a utility with fewer infrastructure components. PSE will make its decision on cost, benefits and value-added functionality in emergency response and restoration.

10.4.2 Develop end-to-end information and business process flows for outage management and emergency restoration processes.
And
10.4.3 Enhance existing technology and systems to close functionality gaps with the strategy of migrating them toward the final architecture.

PSE actions:
PSE partially accepted KEMA's recommendations. Further study is required to evaluate the OMS/GIS solution.

KEMA suggested that PSE map outage management and emergency restoration process flows. Mapping process flows will allow PSE to identify key functionality that should be migrated from existing outage response applications to OMS/GIS systems and will support enhancing current state processes to take advantage of new capabilities realized by implementing these new systems.

Process mapping will be conducted as a preliminary project step if the OMS/GIS cost/benefit analysis proves beneficial to PSE and its customers.

KEMA noted the functional limitations PSE's systems have in comparison to leading practice outage management systems. They included the lack of integration of SCADA/EMS and CLX systems, the need for additional SCADA coverage of distribution circuits and the need to expand distribution automation capabilities. KEMA reviewed PSE's automated metering information (AMI) system and recommended PSE determine if the functionality and gaps of that system can be bridged.

Enhanced SCADA integration (with OMS) will be considered as a part of the cost/benefit analysis that will be completed by first quarter of 2008. In the meantime, PSE continues to evaluate further integration of data sources within existing systems (SCADA/AMR Dashboard/CLX).

SCADA: All of PSE's transmission substations (59 facilities) currently have SCADA. Of the 281 distribution substations in PSE's system, 224 have SCADA. Thirty-two of the remaining 57 substations currently without SCADA will have SCADA installed by year end 2010. PSE has projects scheduled from 2007-2015 to upgrade SCADA in 77 distribution substation facilities. All new substations are installed with SCADA. The projects, when completed, would ensure all but 25 PSE distribution substations will have SCADA by 2015. (The remaining 25 stations are customer leased, submarine stations or are being retired over the next several years.)

Distribution Automation: In the first quarter of 2007 PSE began exploring options for implementing some level of Distribution Automation within PSE's electric distribution system. To gain additional information PSE implemented a Distribution Automation pilot in June 2007. The pilot included installing the appropriate communications equipment to prove communication and to evaluate data elements and control possibilities with a recloser and voltage regulator on a distribution circuit. Results from the pilot should be available in the first quarter 2008. In addition, PSE has planned additional Distribution Automation pilots to further evaluate and explore Distribution Automation over the next five years.

AMI-Cellnet: As recommended, PSE reviewed the functionality and reliability gaps of the Cellnet AMI system for outage reporting and verification. PSE determined that outage reporting cannot be dramatically improved without substantial changes to the supporting radio frequency infrastructure. Negotiations with Cellnet will be initiated in the first six months of 2008. However, outage verification functionality can be improved by taking advantage of a new messaging service being implemented by Cellnet. Once corresponding changes are made to the Meter Data Warehouse, expected to be completed by year-end 2008, PSE will be able to trigger an AMR outage restoration verification shortly after power is restored to a circuit and receive restoration results for customers with AMR metering being served by the circuit within minutes.

Other: On a pilot basis, PSE is testing a handheld electronic Personal Data Assistant (PDA) based device that would allow gathering and transmitting damage assessment information electronically to operating bases. PSE anticipates being able to begin field trials with 10 PDA devices in Pierce and North King operating bases by year-end 2007.

10.4.4 Deploy new systems to close the functionality gaps and build out the outage management architecture.

PSE actions:
PSE is considering KEMA's recommendation.

KEMA noted functionality gaps when comparing PSE's outage response systems to similar systems utilized by benchmark utilities. KEMA observed that PSE's existing outage response tool in ConsumerLinX (CLX) associates customers to a substation circuit. This works well for routine or simple outages where there is a single point of damage on the circuit; however, CLX is quickly overwhelmed when there are multiple points of damage on the same circuit. Additionally, the simplicity of the customer/circuit data model within CLX severely limits the ability to isolate the specific portion of the electric system that is associated to the particular outage. The inability to effectively isolate multiple outages from one/another on the same circuit has cascading impacts: it limits the ability to align damage assessment results to those isolated outages; limits the ability to track resources assigned to the outage, and importantly – limits the ability to provide relevant or individualized outage restoration information to customers.

Further study is underway to evaluate the OMS/GIS solution and develop an integration strategy to address the functionality gaps identified in 10.4.4.

10.4.5 Develop a phased implementation plan for outage management related information system and processes.

PSE actions:
PSE will consider KEMA's recommendation after the definition, requirements and cost/benefit implications are completed.

SUPPORT SERVICES

11.4 RECOMMENDATIONS

11.4.1 Refine the ESERSC (Emergency/Storm Event Response Services Contract) **contract to add the planning, training, communication and evaluation roles necessary to plan for and implement major restoration efforts.**

PSE actions:
PSE did not accept KEMA's recommendation.

PSE did not implement KEMA's recommendation to make changes to the Emergency/Storm Event Response Services Contract (ESERSC, storm contract) with Potelco. However, PSE conducted a thorough review of the current contract language and determined that the roles and responsibilities are appropriately defined. PSE also reviewed documentation of operating base management processes and the CERP and determined that these documents were sufficient. Existing language in the ESERSC includes the following:

- "Service Provider shall be responsible for coordinating damage assessment through their allocation of Service Provider damage assessment teams and requesting assistance from PSE for circuit patrol and other damage assessment as required".
- "Service Provider shall be responsible for mobilizing and assigning Service Provider's resources necessary or appropriate to provide Emergency/Storm Event Response Services including, without limitation, all scheduling necessary to meet PSE priorities, customer commitments, governing agency requirements and contract requirements. Both the PSE Emergency Operations Center and Service Provider shall be responsible for mobilizing such additional resources as are necessary to supplement Service Provider's work force during an Emergency/Storm Event, including, without limitation, flagging personnel, tree

crews and additional line crews, subject to PSE review and approval. Service Provider shall have management direction and control of these Outside Resources and shall assign these Outside Resources in response to PSE priority designations."

- "Service Provider will maintain and operate Storm Boards at pre-designated locations during an Emergency/Storm Event so as to maximize restoration of service to PSE customers as expeditiously as possible and consistent with the PSE Corporate Emergency Response Plan and the Storm Management Plan."

The KEMA conclusion in section 11.3.5 of their report to develop operational metrics for storm events was based on the fact that the contract (ESERSC) referred to an Appendix for Operational Metrics that had not yet been developed. As noted above, PSE believes the current contract language appropriately defines roles and responsibilities without the "to be developed" operational metrics. In addition, PSE's Master Services Agreement with Quanta Services, Inc. (the parent company of Potelco) includes forty (40) operational performance metrics. These metrics cover all services provided by Potelco, including response and restoration. As stated in PSE's Master Services Agreement "Emergency/Storm Event Response performed by Service Provider under this contract shall take precedence over all other work...for PSE or third parties." Given this contract language, PSE does not believe that specific storm event operational metrics are meaningful. PSE is working on amending the ESERSC to eliminate reference to operational metrics specific to storms.

For the 2007 training requirements, PSE established a work order for Potelco employees to charge training time and authorized Potelco to send individuals to this training, if the individuals were not being briefed in some other fashion.

KEMA recommended that PSE clarify and define the communications required between Potelco and the EOC. PSE has implemented an "operations conference call" (Exhibit 11.4.1-A) to enhance information on resource requirements and estimated restoration times. These calls are initiated by the EOC and operating base management from Potelco. At this time PSE feels that these calls are within the scope of the work defined within the ESERSC and do not need to be explicitly identified within the contract.

MATERIALS MANAGEMENT AND LOGISTICS

12.4 RECOMMENDATIONS

12.4.1 Enhance logistics to better support the number of crews supporting the restoration.

PSE actions:
PSE accepted KEMA's recommendation.

KEMA concluded that while PSE's material management practices and functions performed well during the event, PSE's processes were not scaleable to an event of the magnitude of the December 2006 windstorm. They recognized the effort of PSE's EOC and others to create ad hoc practices to respond to the event and recommended that logistics support be enhanced.

PSE is in the process of selecting a 'logistics' vendor to support PSE's needs for crew staging areas and/or establishment of local area coordination sites. Contracts are anticipated to be signed by year-end 2007 with one or two vendors that will provide logistics support such as: mobile offices, walled tents, generators, hot and cold meal provisions, sanitation facilities, fuel, etc.

PSE has also established the new role of "Lodging Coordinator" as an emergency response assignment (Exhibit 12.4.1-A). Forty-three (43) employees have been assigned this role and 40 of them participated in training in October. These employees are responsible for coordinating the lodging needs for all emergency response personnel. PSE has direct bill arrangements with dozens of hotels throughout its service territory, with information available to the lodging coordinators about past experience and contact information. Since 2004/2005, PSE has increased the number of hotels on its directory by 138 percent, increasing from 51 to 119 by October 2007.

12.4.2 Document material management policies and processes created to support storm levels.

PSE actions:
PSE accepted KEMA's recommendations.

KEMA noted a number of recommendations, each *(in italics)* addressed below.

Document the material requirements procured during the December 14-15 storm restoration effort;

> The recommended action has been completed. Materials procured during the December 14-15, 2006 storm were tracked, analyzed post-storm and documented. Documentation for major storms since the 1993 Inauguration Day Storm has been retained and is considered when establishing storm materials inventory target levels.

Document the new processes created to source, procure and ship materials on a short lead-time basis;

> Pre-December 14-15, 2006 storm sourcing and shipping procedures proved to be highly effective. Nonetheless, post-storm debriefing sessions were held with major storm suppliers (pole-line hardware, materials, transformers, cable/wire, etc.) and our partnered transport logistics provider with a goal to identify improvement opportunities. New processes have been incorporated into the Purchasing/Materials Management's Emergency Manual and include use of an

enhanced materials order form aimed to expedite placement of orders by ensuring all required data has been provided and improved order tracking (Exhibit 12.4.2-A). Ground transport deliveries were timely and met storm materials delivery needs, as did delivery of large quantities of materials via airfreight. However, it is recognized procedures should include an advance acknowledgement of air transportation needs, even when unlikely; thereby reducing the risk of delay in air transport. Further, Purchasing/Materials Management recognize, through shared experience, that emergencies have unique characteristics and as such future emergencies could prevent the landing of air transport in the region (heavy snow, earthquake).

Review the additional stores requirements for the anticipated storm season and balance against the usage rate during the season. PSE should consider increasing stock levels to cover the first eight to ten days of a major restoration effort;

Stores requirements underwent an after-event review. Traditionally, the inventory of storm materials is built up to targets starting in August in advance of storm season, considered to be October to April. From May through July storm inventory is allowed to decrease to desired non-storm season levels. However, as a result of the December 14-15 storm and sustained longer lead-times in the marketplace, emergency materials will be sustained at target levels year round. The change will provide protection against an unexpected storm or emergency outside of "normal" storm season and in the event there are material supply challenges during the August-September storm inventory build-up period. In addition, storm materials overall will be maintained at a higher level which will extend the time during restoration efforts where materials can be supplied out of existing stock.

It is important to note PSE has been successful in sharing the carrying cost of storm materials with its major suppliers, alleviating the need for the company to hold excessive levels of inventory for storm restoration and normal operations. The major suppliers are strategically located. For example, a major distribution transformer supplier maintains a large inventory of distribution transformers of various sizes on consignment at PSE's central warehouse. Another transformer supplier is based within an hour of PSE's service territory. The company's primary major pole-line hardware and materials supplier maintains a satellite warehouse in Auburn, Washington dedicated primarily to PSE. PSE's long-term pole supplier locates its primary manufacturing plant within the PSE service territory and has passed its annual audit of emergency storm stock this past summer. The company's primary wire supplier has a satellite warehouse in Seattle. Three major material suppliers are located in Portland, Oregon. Further, manufacture of PSE's overhead repair wire is performed in Roseburg, Oregon. The company also has major stocking distributors and manufacturers of all storm materials and equipment out of state which protects against a major earthquake or disaster on the West Coast. The 24/7 contact information for each of these critical supply partners is maintained and updated on an annual basis in Purchasing/Materials Management's Emergency Manual.

Arrange for critical materials to be stored on site as vendor stock that can be released on short notice with email confirmation to purchase from PSE; and

PSE has a vendor managed transformer inventory arrangement at its central warehouse in Kent. The consignment transformer inventory can be drawn upon at any time. The company also has materials suppliers with satellite warehouses in PSE's service territory (i.e., Auburn, Seattle) which provided timely re-supplying during the 2006-2007 storm season. Further, PSE stipulates emergency storm stock requirements of its stocking distributor partners within its material contracts. An after-event action taken was a full audit of these requirements on PSE's (two) primary stocking distributors. Each passed this audit with 100 percent accurate and maintained storm stock at their warehouses within two hours of PSE's service territory.

Prearrange for expedited shipping to ensure availability of transport as well as best pricing.

PSE has pre-existing shipping arrangements with current suppliers and uses a transportation logistics provider, as needed, to procure transportation based on ability to deliver, timing and cost-effectiveness. This practice has been recognized by our suppliers as a best practice in relation to expedited and accurate emergency order fulfillments.

POST-EVENT REVIEW

13.4 RECOMMENDATIONS

13.4.1 Ensure the existing post-storm actions and recommendations are consistent with the leading practice model presented in this report.

PSE actions:
PSE accepted KEMA's recommendation.

KEMA recommended that PSE consolidate all ongoing actions and recommendations from internal storm debriefings, the Governor's After Action Review and customer feedback, prioritize them for implementation, and develop a master work plan with schedules, assignments, etc.

PSE has developed a master task list (see Exhibit 13.4.1-A) incorporating recommendations from PSE internal storm debriefs held during the weeks following the December 14-15 windstorm, the Governor's After Action Review recommendations pertinent to PSE, and customer focus group and survey input. The company formed the Emergency Event Management and Communication Team (EEMAC) to lead the efforts in implementing actions and processes based on the consolidated list of recommendations. EEMAC is a team of four operations managers lead by a project manager (currently the

Director Electric Operations). Each operations manager has an assigned focus area. The four areas of focus for implementing recommendations are as follows: Operations; Technology; System Hardening; and Customer Service and Communications.

Actions to be taken were categorized into what could be accomplished for the 2007-08 storm season, what may be accomplished by the 2008-09 storm season, and those that were longer-term initiatives (e.g., the study and potential implementation of an OMS/GIS system; system hardening, etc.).

INFRASTRUCTURE CONDITIONS

14.4 RECOMMENDATIONS

14.4.1 Enhance PSE's transmission vegetation management policy and standards for ROW width.

PSE actions:
PSE partially accepted KEMA's recommendation.

KEMA recognized that PSE and other utilities in our region face challenges in addressing wider rights of way (ROWs) and increased vegetation management programs due to political and social pressures. KEMA recommended that PSE work with other utilities in the region to change public perception to support improved reliability, consistent with NERC guidelines, as well as formalize a plan to broaden ROWs in particularly hard hit areas.

PSE continues to address the challenges in gaining wider ROWs, working with local jurisdictions across our service territory. PSE is working proactively with key stakeholders to develop and introduce legislative and regulatory solutions for vegetation management policy issues including:

- Creating healthier buffers when lands are converted for development.
- Hazardous trees outside existing ROWs that present risk to utility infrastructure.
- Ensuring vegetation within utility ROWs is compatible.

PSE has solicited a proposal from a consultant to evaluate PSE's existing practices for vegetation management along high voltage distribution lines, and to offer suggestions for improvements. (Exhibit 14.4.1-A: Abstract developed by consultant as sample of work.)

Additionally, PSE increased its vegetation management spending by $2 million, for a total expenditure of $12 million in 2007.

14.4.2 Aggressively develop and maintain cross country transmission access roads.

PSE actions:
PSE accepted KEMA's recommendation.

KEMA noted in certain cases poor accessibility to transmission system access roads created delays in transmission restoration. KEMA recommended we continue our efforts to catalogue all existing access roads and develop a comprehensive access road program for cross country transmission lines.

PSE recently initiated a project to consolidate information on access point locations, and transmission pole location information. This project will result in marking transmission poles at road crossings with the transmission line name to enhance helicopter patrols and damage assessment data gathering. PSE has allocated funds for ongoing work on the maintenance of access points and access along critical rights of way.

14.4.3 Evaluate hardening opportunities for both transmission and distribution.

PSE actions:
PSE accepted KEMA's recommendation.

KEMA recommended that we undertake a system hardening study to identify additional opportunities for under-grounding, as well as the use of different tower/pole designs in particularly hard hit areas.

PSE has identified a number of system enhancements that may improve the electric system's resilience to minor or major storm events. Enhancements considered include the following: design changes to reduce overhead electric line exposure to trees and windblown limbs; reviewing the type of fuses that are installed in the field; installing switches that will allow isolation of sections of line damaged for service restoration; strengthening selected transmission line structures to reduce damage due to trees; labeling more transmission structures for ease in identifying damaged circuits in a storm; and looking at opportunities for the use of "breakaway" devices that will prevent major damage to transmission structures when the lines are struck by trees.

Next steps include the development of relative costs for each of these opportunities, and identification of the number of locations where PSE may make these improvements. PSE expects to complete the evaluation phase of the work by first quarter 2008.

In the second quarter 2008 PSE will bring in a consultant to review these tactics and relative costs and to identify additional techniques with cost information that should be considered in the system planning process.

Exhibits Index

Exhibits Index continued

PUGET SOUND ENERGY

The energy to do great things

pse.com

15 May 2007

To: NAME, Mail Stop

From: Mark Wesolowski
Emergency Planning Manager

Re: 2007/2008 Emergency Response Assignment

Following one of the most significant storm seasons we've ever experienced, we're making preparations for the upcoming year. Below is your emergency response assignment for 2007/2008 as well as the contact information we have on file you. Please take a moment to review your assignment and verify the accuracy of your contact information.

Training or orientation may be ***required*** for your assignment. Additional information about training/ orientation will be provided once the training schedule has been determined. Damage assessor and crew coordinator training may start as soon as the last week of June and will be completed by the first week of August. All other training and orientations will take place in August/September.

Primary ER Assignment:	Assignment
Primary ER Location:	Location*
Role Description:	«Role_Description»
Secondary ER Assignment:	Assignment
Secondary ER Location:	*

* The nature of the emergency may necessitate working from other locations

Your Contact Information

Home:	Number
Cellular:	«Cellular_Phone»
Number to call first:	Unknown

Should you have any questions regarding your assignment, or need to make corrections to your contact information, please contact Kathryn (Kathe) Conner at (81) 2847 or by e-mail.

If you haven't already done so, I encourage you to become personally prepared both at home and work. Preparedness information is available at web sites such as 3days3ways.org, Ready America (ready.gov) and, the American Red Cross (www.redcross.org).

Category	Focus	What's Changed or New?	Benefit	Who
Customer Communication	Operations Base Communications Narratives	Request area specific damage and restoration information from each operating base for use in media and customer messaging.	Improved customer messaging; reduced escalated calls.	**Base**
Interagency Coord	Utility Road Clearing Task Force	***In process (expected completion 11/30/07)***: formalizing plan for teaming qualified tree crews, Potelco, roads crews for clearing and making safe public roadways.	Coordinated and planned approach to clearing downed wire/trees. Improves road openings.	**Base**
Process Improvement	Early Storm Restoration Estimates	Developed process to deliver Regional storm restoration estimates within the first 24 hours of an event.	Enhances customer outage communications.	**Base**
Process Improvement	Training	Enhanced training to include skills testing; trained over 150 PSE and Potelco damage assessors.	Skilled, qualified emergency response personnel; increased numbers of trained personnel.	**Base**
Process Improvement	Damage Assessment Strategy	Windshield assessment within first 24 hours; with area specific assessment and restoration times in 48-72 hours.	Timely information to customers on event characterization; estimated restoration times by region or area early in response effort.	**Base**
Process Improvement	Local Area Coordination	Formalized process for establishing, sourcing and supporting local area coordination sites.	Streamlines process for staffing, sourcing and supporting logistics needs in a specific area. Provides a PSE community presence and expedites system restoration.	**Base**
Process Improvement	Lodging Coordination	New emergency response role defined and staffed.	Relieves EOC and Storm Base operations from lodging coordination.	**Base**
Process Improvement	Personnel Tracking	Potelco developed personnel tracking system for all event response personnel.	Improves resource management and documents for billing purposes.	**Base**
System Operability	ROW & Access Roads	Additional ROW clearing and access road work at multiple locations within King and Pierce Counties. Additional work planned in Kitsap County.	Allows more efficient travel along ROW and reduces assessment and restoration time.	**Base**
System Operability	Whidbey Base	Plan developed to open Whidbey Operating Base.	Presence on Island for customer service and may enhance management of restoration efforts.	**Base**

Category	Focus	What's Changed or New?	Benefit	Who
Tools/Equip	GPS	Purchased 200 GPS units to be stocked in Storm Bases for damage assessors, crew coordinators and/or foreign crews.	Improves assessment and response time.	**Base**
Tools/Equip	Storm Bags	New bags stocked and managed by materials management for Storm Bases.	Provides required tools for damage assessors and crew coordinators; streamlines process of restocking bags post event.	**Base**
Tools/Equip	Damage Assessment Hand Held	Piloting hand held computers for loading damage assessment information. Anticipate pilot in Pierce and North King for 2007-08 season.	Based on pilot, anticipate reduction in time to obtain quality damage assessment information from field.	**Base**
Customer Communication	Escalated Call Process	Designated employee at each operating base as point person for obtaining restoration information for use by CRM's, Major Accounts/BAS, escalated calls, etc.	Formalizes process for obtaining needed customer or restoration information from storm bases without burdening those directly involved in restoration.	**CAC**
Customer Communication	Customer Communications Program Manager	New position to coordinate communications between Corporate Communications and Call Center.	Improved and consistent customer messaging.	**CAC**
Customer Communication	Agents at Home	Agents at Home staffed to 30 (from 14 previously)	Improved customer service in early hours of event.	**CAC**
Process Improvement	Bothell Emergency Center	Created Call Center "EOC" for managing customer service staffing, etc.	Duty teams assigned to manage staffing and customer service levels.	**CAC**
Process Improvement	Helicopters, Flaggers	Added helicopter and flagging resources. Out of State flaggers exempted from WA State Certification	Added resources.	**EOC**
Customer Communication	Web Portal	***In process:*** development of a Web-based tool for non-call center personnel to process outage calls.	Reduces time and streamlines process to provide customer service.	**PSE**
Customer Communication	Customer Education	Major Accounts/Business Account Services educating customers on KEMA report, post-storm initiatives, etc.	Customers better educated on electric service and PSE's response and recovery activities.	**PSE**
Customer Communication	PSE.com	Service Alert link for simultaneous posting on PSE.com and PSE web (intranet); Outage map to be posed to PSE.com	Improved customer messaging.	**PSE**

Category	Focus	What's Changed or New?	Benefit	Who
Customer Communication	Customer Emergency Preparedness Card	Wallet card to be distributed with October bills to all customers.	Vehicle to message personal preparedness and easy access to PSE 1-888 number to report emergencies and other local agencies for assistance.	**PSE**
Interagency Coord	Memorandum of Understanding with State EMD	***In process (expected completion 11/15/07)*** documenting concept of operations between PSE, State EMD, WS DOT, WSP, CTED and UTC.	Documents PSE's role in providing State information on status of system and State's role in assisting PSE with HOV lane exemptions, expediting state border crossings for foreign crews, etc.	**PSE**
Interagency Coord	EOC Liaisons	New emergency response role defined and staffed for County and State EOC's.	Provides point of contact for interagency coordination during event.	**PSE**
Interagency Coord	County Pre Winter Storm Meetings	Meetings hosted by PSE in 7 counties with County emergency management, public works, and first responders.	Share contact information and PSE's plan for event response and restoration.	**PSE**
Process Improvement	Storm Levels	Levels 0-3 identified with varying response actions associated with each. 3 = major (e.g. December 2006 windstorm) ***(See attachment)***	Sets expectation for level of response; documented in Corporate Emergency Response Plan.	**PSE**
Process Improvement	Transmission Restoration Prioritization	Formalized process for activating the transmission restoration prioritization team; dedicated space and resources sited in ESO.	Streamlines process for siting, sourcing and establishing responsibilities for prioritizing transmission restoration.	**PSE**
Process Improvement	Logistics	RFP for selection of logistics vendor to support local area coordination sites and staging areas. (expect selection by end of October 2007)	One call for logistics support (mobile offices, tents, sanitation, water, food, heat, generation, etc.)	**PSE**
Process Improvement	Corporate Emergency Response Plan (Vol. I and II)	Adding storm level descriptions, checklists, additional detail for materials, and critical facility restoration priorities	Improved plan documents for use in event response.	**PSE**
System Operability	Vegetation Management	Additional vegetation management at areas of concern across the service territory.	Removes specific vegetation issues that could cause outages during storm events.	**PSE**

Category	Focus	What's Changed or New?	Benefit	Who
System Operability	System Hardening	Identifying opportunities to make the electric system more resilient to storm events, and improve ability to access the system so repairs can be performed when necessary. Areas of focus include ROW clearing, access roads, system hardening, and identification of exceptionally critical facilities.	Provides long range plan for infrastructure improvements.	**PSE**
Process Improvement	Enhanced Storm Base Handoff	Enhances existing storm base handoff process.	Enhances Regional storm base ability to quickly gain an understanding of system damage, resources in the field and resources needed.	**SO**
Process Improvement	911 Call Taking	Doubling capacity for "911" call taking in System Operations	Improves service for life/safety emergency response.	**SO**
System Operability	Self Protection Clearances	Developed new process for enhancing use of self-protection clearance procedures to include adding a designated Regional contact at system operations to manage only self-protection clearance calls.	Reduces bottleneck and congestion into System Operations from field for switching and clearances.	**SO**
System Operability	Local Area Coordination Clearance Procedures	Developed new process for enhancing use of local area coordination clearance procedures to include reduced use of I #'s and broader area clearances.	Reduces bottleneck and congestion into System Operations from field for switching and clearances.	**SO**
System Operability	System Operations Staffing	Developed a staffing plan that aligns field and system operations staffing levels during peak restoration periods and rest periods.	Reduces bottleneck and congestion into System Operations from field for switching and clearances.	**SO**
Tools/Equip	Radio /Channels/Frequencies	Added 2 additional channels; 1 in King; 1 in Whatcom County	Reduces bottleneck and congestion into System Operations from field for switching and clearances.	**SO**
Tools/Equip	System Operation Consoles	Increased number of workstations.	Reduces bottleneck and congestion into System Operations from field for switching and clearances.	**SO**
Tools/Equip	Business Account Services - Phone Line	Installed new "1-800" line for business account services. (In addition to existing line for Major Accounts)	Eases access to system supervisor and/or EOC for schools, hospitals, water/wastewater plants, etc. to obtain outage restoration information.	**SO**

PSE PUGET SOUND ENERGY
The Energy To Do Great Things

EVENT CATEGORIES

Levels	Electric Criteria	Gas Criteria	Level of Response	Operations Actions
Level 0 - Normal	Nominal conditions across system	Nominal conditions across system	Normal daily response activity.	Normal operations.
Level 1 – Regional	Event localized to individual geographic areas; resources within region adequate for response.	Localized event managed with PSE regional resources.	Operations base(s) open; coordination with system operations or gas control. Gas Planning Strategy Center open for gas emergencies.	EOC not opened. Internal resources utilized. Some use of employees with ER assignments.
Level 2 – Significant	Multiple regions affected; requires resources from other PSE regions and/or outside PSE service territory.	Multiple PSE regions affected; requires resources to be allocated to other PSE regions.	EOC open; multiple operating bases and may activate local area coordination. Employees with emergency response assignments mobilized.	EOC opened. Additional contractor resources needed; some from bordering states. Moderate to extensive use of employees with ER assignments. Windshield assessment utilized. Complete assessment within 24-36 hrs. Local Area Coordination possible.
Level 3 – Major	Most or all regions affected; maximum level response required; need extensive resources from outside area.	Most or all PSE regions affected; may request operator qualified resources from outside PSE.	EOC open; most or all operating bases open; external logistics support may be employed; full corporate response to support restoration efforts.	EOC opened. Resources obtained from outside of region. Full utilization of employees with ER assignments. Local area coordination implemented. Windshield assessment utilized; complete assessment within 48-72hrs.

See Page 2 for Event Triggers and Criteria

EVENT TRIGGERS and CRITERIA

Levels	Declared by	When	Triggers	Criteria
Level 0 - Normal	System Supervisor	At event end, when returning to normal operations, as final Storm Declaration is issued.	All operating bases are deemed to be "closed" or returning to non-storm work.	
Level 1 – Regional	System Supervisor	Following storm forecast by National Weather Service or, when issuing Storm Declaration.	Operations base(s) opened for storm restoration work.	EOC is not open.
Level 2 – Significant	System Supervisor	Following severe storm forecast by National Weather Service or, when operating base(s) and the EOC are opened.	Several operating bases and the EOC are open. Additional crews are required from within northwest region.	EOC is open. Multi-day restoration. Resources obtained from WA/OR/CA/ID/MT.
Level 3 – Major	System Supervisor	Following major storm forecast by National Weather Service or, most or all operating bases and the EOC are open.	Most or all operating bases and the EOC are open. Additional crews are required from beyond the northwest region. External logistics support required. Full corporate response is required to support restoration efforts.	EOC open. Extended restoration timeline. Resources obtained from beyond WA/OR/CA/ID/MT. Full utilization of employees with ER assignments.

PUGET SOUND ENERGY

Storm Base Expectations for 2007-08

- "Own it"
- Storm Levels (1, 2, or 3) will be declared *(see attachment).*
- "Windshield" assessment in each region within 24 hours.
    - Goal: area specific estimated restoration times within 48-72 hours of event subsiding.
- Focus on critical facility restoration prioritization (lists in Volume II).
- Create restoration plan – document it & communicate it.
- Commitment to estimated restoration times communicated to customers.
- Operations conference calls 2X/day (suggested at shift changes):
    - EOC to establish after opening.
    - Participants to include EOC Director/Manager, Potelco base managers and PSE EFR supervisors.
    - Provide best available information & refine as new information available.
- Track resources (crews, assessors, servicemen, etc.)
- Establish local area coordination as needed to enhance restoration and customer communications.
- Open Whidbey Operating Base as a storm board as appropriate.
- Utilize escalated call process.

4.4.1-B2

4.4.1-B2

PUGET SOUND ENERGY
The Energy To Do Great Things

Emergency Operations Center Orientation
2007-08 Storm Season

October 10, 17 and 24, 2007

Agenda

- Introductions *(name and EOC role)*
- Mission and Measures of Success
- Facility Overview
- EOC "Opening"
- New for 2007-08 Season
- Resources
- Q & A

Mission: Develop and implement a customer centered outage restoration process, scalable to any size emergency event.

<u>Measures of Success 2007-08 Season:</u>

- Customer outage restoration estimates are available and communicated.
- We commit to meeting all outage restoration times as communicated to our customers.
- All restoration times are communicated; General within 24 hours;
- Specific estimates for customers in all areas within 48-72 hours of event declaration.

EOC Facility Overview

- EOC Main Room
- EMS / Radio Room
- EOC Conference Room
- Kitchen
- Transmission Restoration Team ("t-pod")
- Load Office
- System Operations
- 911 Call Takers

Opening the EOC-Aides

- EOC Manager/Director Packets
- Administrative Support *Quick Reference Guides*
- Volume II

Initial Actions

- Get status report from System Supervisor
- Open phones
- Send initial "EOC OPEN" Update
- Open CLX & run updates
- Set schedules for…
  - EOC 4-hour Updates (Internal and External)
  - Shift change
  - Operations Conference Calls (2 X's/day)
  - Communications/Customer Service Conference Calls (4 X's/day)
- Notify 2nd EOC shift personnel

Operations
Conference Call Agenda ***(Rev. 10-5-07)***
SCHEDULE INITIATED BY EOC
(Calls tentatively scheduled at 06:30 and 14:30 (or close to shift changes at bases)

Subject	***Responsibility***	***Est. Time***
Weather Update	EOC	1 min.
Storm Base Reports ▪# outages ▪Subs out ▪Transmission out ▪Estimated overall damage *(% of area hit; % assessed)* ▪# crews working and on-site ▪# crews en route/time expected ▪Resources needed??? *(damage assessment, CLX, tree/line crews, flaggers, materials, etc.)* ▪Restoration plan ▪Staffing plan; *shift change (who and when)*	Potelco Base Manager & EFR Supervisor	5 min/base
Storm Characterization – *for customer communications*	All	3 min.
Priority Issues	All	3 min.

Call bridge to be established for each call by Admin. Support

Corporate Communications/
Customer Service
Conference Call Agenda ***(Rev. 10-5-07)***
SCHEDULE INITIATED BY EOC
(Calls tentatively scheduled at 10:00 am, 4:00 pm, 8:00 pm 4:00 am)

Overview	2 min.
Weather	1 min.
Base Highlights	3 min.
Access Center Highlights	3 min.
Community Highlights	3 min.
Media	3 min.
Special Priority Issues **(15 minutes total)**	2 min.

"Continuous/Permanent" Call Bridge Established:
425-456-2500 or 81-2500 or 1-888-228-0484
Meeting ID: 2525
Password: 44444

Where to find forms…

- Public Folder…
- "EmergencyOpsCtr"
  - EOC Duty Roster
  - Conference Call Agendas (and who should be notified for call)
  - EOC Update Form
  - Misc. Forms

New for 2007-08 (handouts)

Process Improvements…

- Early storm restoration estimates
- Enhanced storm base handoff
- Storm Levels *(1-yellow, 2-orange, 3-red)*
- Training *(DA, CCC, CLX, 911, Dispatchers, Drivers, Lodging Coordinators)*
- Damage assessment strategy
- Local area coordination *("pods")*
- Transmission restoration prioritization

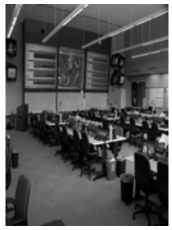
More process improvements…

- Logistics
- Lodging coordination
- 911 call taking
- CERP – Volume I and II
- Add'l helicopter and flagging contracts
- Personnel tracking
- Bothell emergency operations center

Tool & Equipment…

- Radio channels/frequencies *(S. King, Whatcom)*
- System Operations – added consoles
- GPS *(200 units)*
- Storm bags
- 2nd 1-800 line for Major Accounts
- Damage assessment hand-held – pilot

Interagency Coordination…

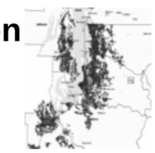


- Utility Road Clearing Task Force
- MOU with State Emergency Management Division
  - HOV Lane Exemption
  - State Border Crossings
- EOC liaisons – counties and State
- County pre-winter storm meetings

System Operability…

- Whidbey Operating Base
- ROW & access roads
- Vegetation management
- System hardening
- Self protection clearances
- Local Area Coordination clearance procedures
- System operations staffing plan

Customer Communication



- Web portal
- Customer education
- Operations base communications narratives
- Escalated call process
- www.pse.com
- Customer emergency preparedness card
- Customer Communications Program Manager
- Agents at home *(30)*

Miscellaneous…

- Kitsap to operate out of Poulsbo
- New storm board maps
- Increased training and depth for back-up dispatchers
- Checklist for contracting "foreign crews"

Resources

- Quick Reference Guides
- Volume II
- Employee Contact Lists
- Lodging Coordinator Procedures
- Major Accounts & Business Account Services Reference Manual
- Critical Facility Restoration Priority Lists *(by region)*
- Public Folder: "EmergencyOpsCtr"
- X Drive: "Storm Support"; "Storm Stats"; "EMS Engineering"
- System Supervisor

Are we ready????

Questions????

- Mark Wesolowski
  - 425-462-3962 (office)
  - 425-766-4148 (cell)

- Mary Robinson
  - 425-462-3887 (office)
  - 425-766-3888 (cell)

Rev. 10/02/2007

Puget Sound Energy
2007-08 Storm Season
Plan Enhancements

Process Improvements	What's Changed or New?	Benefit
Early Storm Restoration Estimates	Developed process to deliver Regional storm restoration estimates within the first 24 hours of an event.	Enhances customer outage communications.
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Puget Sound Energy
2007-08 Storm Season
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Rev. 10/02/2007

Puget Sound Energy
2007-08 Storm Season
Plan Enhancements

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Rev. 10/02/2007

Puget Sound Energy
2007-08 Storm Season
Plan Enhancements

Interagency Coordination	What's Changed or New?	Benefit
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Memorandum of Understanding with State EMD	***In process (expected completion 11/15/07)*** documenting concept of operations between PSE, State EMD, WS DOT, WSP, CTED and UTC.	Documents PSE's role in providing State information on status of system and State's role in assisting PSE with HOV lane exemptions, expediting state border crossings for foreign crews, etc.
EOC Liaisons	New emergency response role defined and staffed for County and State EOC's.	Provides point of contact for interagency coordination during event.
County Pre Winter Storm Meetings	Meetings hosted by PSE in 7 counties with County emergency management, public works, and first responders.	Share contact information and PSE's plan for event response and restoration.

Puget Sound Energy
2007-08 Storm Season
Plan Enhancements

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Puget Sound Energy
2007-08 Storm Season
Plan Enhancements

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PSE.com	Service Alert link for simultaneous posting on PSE.com and PSE web (intranet); Outage map to be posted to PSE.com	Improved customer messaging.
Customer Emergency Preparedness Card	Wallet card to be distributed with October bills to all customers.	Vehicle to message personal preparedness and easy access to PSE 1-888 number to report emergencies and other local agencies for assistance.
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PUGET SOUND ENERGY
The Energy To Do Great Things

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See Page 2 for Event Triggers and Criteria

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AGENDA

Fall Storm Leadership Meeting – PSE/Potelco

October 3, 2007
11:00 a.m. – 2:00 p.m.
Summit Conference Room

11:00 a.m. – 11:15 a.m.	**Introductions**
11:15 a.m. – 11:45 a.m.	**National Weather Service** *Ted Buehner*
11:45 a.m. – 11:55 a.m.	**Break to Grab Lunch**
11:55 a.m. – 12:20 p.m.	**Storm Planning - Going Forward** *Bert Valdman* *Greg Zeller* *Mark Soetenga*
12:20 p.m. – 12:50 p.m.	**Emergency Event Management and Communication Team Update** *Operations* — *Mary Robinson* *Communications/Customer Service* — *Janet Gaines* *System Hardening* — *Shamish Patel* *Technology* — *Greg Zeller*
12:50 p.m. – 1:20 p.m.	**What's New for 2007-08**
1:20 p.m. – 1:40 p.m.	**Expectations of Leadership**
1:40 p.m. - 2:00 p.m.	**Questions???** **Adjourn**

PUGET SOUND ENERGY

Emergency Event Management and Communication Team

Mission:

Develop and implement a customer centered outage restoration process, scalable to any size emergency event.

Measures of Success 2007-08 Season:

- Customer outage restoration estimates are available and communicated.
- We commit to meeting all outage restoration times as communicated to our customers.
- All restoration times are communicated; General within 24 hours; Specific estimates for customers in all areas within 48-72 hours of event declaration.

Rev. 10/02/2007

Puget Sound Energy
2007-08 Storm Season
Plan Enhancements

Process Improvements	What's Changed or New?	Benefit
Early Storm Restoration Estimates	Developed process to deliver Regional storm restoration estimates within the first 24 hours of an event.	Enhances customer outage communications.
Enhanced Storm Base Handoff	Enhances existing storm base handoff process.	Enhances Regional storm base ability to quickly gain an understanding of system damage, resources in the field and resources needed.
Storm Levels	Levels 0-3 identified with varying response actions associated with each. 3 = major (e.g. December 2006 windstorm) ***(See attachment)***	Sets expectation for level of response; documented in Corporate Emergency Response Plan.
Training (DA, CLX, Crew Coordinator, 911, Dispatcher, Lodging Coordinator, Driver)	Enhanced training to include skills testing; trained over 150 PSE and Potelco damage assessors.	Skilled, qualified emergency response personnel; increased numbers of trained personnel.
Damage Assessment Strategy	Windshield assessment within first 24 hours; with area specific assessment and restoration times in 48 72 hours.	Timely information to customers on event characterization; estimated restoration times by region or area early in response effort.
Local Area Coordination	Formalized process for establishing, sourcing and supporting local area coordination sites.	Streamlines process for staffing, sourcing and supporting logistics needs in a specific area. Provides a PSE community presence and expedites system restoration.
Transmission Restoration Prioritization	Formalized process for activating the transmission restoration prioritization team; dedicated space and resources sited in ESO.	Streamlines process for siting, sourcing and establishing responsibilities for prioritizing transmission restoration.
Logistics	RFP for selection of logistics vendor to support local area coordination sites and staging areas. (expect selection by end of October 2007)	One call for logistics support (mobile offices, tents, sanitation, water, food, heat, generation, etc.)
Lodging Coordination	New emergency response role defined and staffed.	Relieves EOC and Storm Base operations from lodging coordination.
911 Call Taking	Doubling capacity for "911" call taking in System Operations	Improves service for life/safety emergency response.

Rev. 10/02/2007

Puget Sound Energy
2007-08 Storm Season
Plan Enhancements

Process Improvements	What's Changed or New?	Benefit
Corporate Emergency Response Plan (Vol. I and II)	Adding storm level descriptions, checklists, additional detail for materials, and critical facility restoration priorities	Improved plan documents for use in event response.
Helicopters, Flaggers	Added helicopter and flagging resources. Out of State flaggers exempted from WA State Certification	Added resources.
Personnel Tracking	Potelco developed personnel tracking system for all event response personnel.	Improves resource management and documents for billing purposes.
Bothell Emergency Center	Created Call Center "EOC" for managing customer service staffing, etc.	Duty teams assigned to manage staffing and customer service levels.

Rev. 10/02/2007

Puget Sound Energy
2007-08 Storm Season
Plan Enhancements

Tools & Equipment	What's Changed or New?	Benefit
Radio /Channels/Frequencies	Added 2 additional channels; 1 in King; 1 in Whatcom County	Reduces bottleneck and congestion into System Operations from field for switching and clearances.
System Operation Consoles	Increased number of workstations.	Reduces bottleneck and congestion into System Operations from field for switching and clearances.
GPS	Purchased 200 GPS units to be stocked in Storm Bases for damage assessors, crew coordinators and/or foreign crews.	Improves assessment and response time.
Storm Bags	New bags stocked and managed by materials management for Storm Bases.	Provides required tools for damage assessors and crew coordinators; streamlines process of restocking bags post event.
Business Account Services - Phone Line	Installed new "1-800" line for top major accounts.	Eases access to system supervisor and/or EOC for schools, hospitals, water/wastewater plants, etc. to obtain outage restoration information.
Damage Assessment Hand Held	Piloting hand held computers for loading damage assessment information. Anticipate pilot in Pierce and North King for 2007-08 season.	Based on pilot, anticipate reduction in time to obtain quality damage assessment information from field.

Puget Sound Energy
2007-08 Storm Season
Plan Enhancements

Interagency Coordination	What's Changed or New?	Benefit
Utility Road Clearing Task Force	***In process (expected completion 11/30/07)***: formalizing plan for teaming qualified tree crews, Potelco, roads crews for clearing and making safe public roadways.	Coordinated and planned approach to clearing downed wire/trees. Improves road openings.
Memorandum of Understanding with State EMD	***In process (expected completion 11/15/07)*** documenting concept of operations between PSE, State EMD, WS DOT, WSP, CTED and UTC.	Documents PSE's role in providing State information on status of system and State's role in assisting PSE with HOV lane exemptions, expediting state border crossings for foreign crews, etc.
EOC Liaisons	New emergency response role defined and staffed for County and State EOC's.	Provides point of contact for interagency coordination during event.
County Pre Winter Storm Meetings	Meetings hosted by PSE in 7 counties with County emergency management, public works, and first responders.	Share contact information and PSE's plan for event response and restoration.

Puget Sound Energy
2007-08 Storm Season
Plan Enhancements

Rev. 10/02/2007

System Operability	What's Changed or New?	Benefit
Whidbey Base	Plan developed to open Whidbey Operating Base.	Presence on Island for customer service and may enhance management of restoration efforts.
ROW & Access Roads	Additional ROW clearing and access road work at multiple locations within King and Pierce Counties. Additional work planned in Kitsap County.	Allows more efficient travel along ROW and reduces assessment and restoration time.
Vegetation Management	Additional vegetation management at areas of concern across the service territory.	Removes specific vegetation issues that could cause outages during storm events.
System Hardening	Identifying opportunities to make the electric system more resilient to storm events, and improve ability to access the system so repairs can be performed when necessary. Areas of focus include ROW clearing, access roads, system hardening, and identification of exceptionally critical facilities.	Provides long range plan for infrastructure improvements.
Self Protection Clearances	Developed new process for enhancing use of self-protection clearance procedures to include adding a designated Regional contact at system operations to manage only self-protection clearance calls.	Reduces bottleneck and congestion into System Operations from field for switching and clearances.
Local Area Coordination Clearance Procedures	Developed new process for enhancing use of local area coordination clearance procedures to include reduced use of I #'s and broader area clearances.	Reduces bottleneck and congestion into System Operations from field for switching and clearances.
System Operations Staffing Plan	Developed a staffing plan that aligns field and system operations staffing levels during peak restoration periods and rest periods.	Reduces bottleneck and congestion into System Operations from field for switching and clearances.

Rev. 10/02/2007

Puget Sound Energy
2007-08 Storm Season
Plan Enhancements

Customer Communication	What's Changed or New?	Benefit
Web Portal	***In process:*** development of a Web-based tool for non-call center personnel to process outage calls.	Reduces time and streamlines process to provide customer service.
Customer Education	Major Accounts/Business Account Services educating customers on KEMA report, post-storm initiatives, etc.	Customers better educated on electric service and PSE's response and recovery activities.
Operations Base Communications Narratives	Request area specific damage and restoration information from each operating base for use in media and customer messaging.	Improved customer messaging; reduced escalated calls.
Escalated Call Process	Designated employee at each operating base as point person for obtaining restoration information for use by CRM's, Major Accounts/BAS, escalated calls, etc.	Formalizes process for obtaining needed customer or restoration information from storm bases without burdening those directly involved in restoration.
PSE.com	Service Alert link for simultaneous posting on PSE.com and PSE web (intranet); Outage map to be posted to PSE.com	Improved customer messaging.
Customer Emergency Preparedness Card	Wallet card to be distributed with October bills to all customers.	Vehicle to message personal preparedness and easy access to PSE 1-888 number to report emergencies and other local agencies for assistance.
Customer Communications Program Manager	New position to coordinate communications between Corporate Communications and Call Center.	Improved and consistent customer messaging.
Agents at Home	Agents at Home staffed to 30 (from 14 previously)	Improved customer service in early hours of event.

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PUGET SOUND ENERGY

Expectations of Storm Leadership for 2007-08

- "Own It".
- Declare Storm Level (1, 2, or 3) *(see attachment)*.
- "Windshield" assessment in each region within 24 hours.
- Goal: area specific estimated restoration times within 48-72 hours of event subsiding.
- Commitment to estimated restoration times communicated to customers.
- Operations conference calls 2's/day (suggested at shift changes):
  - EOC to establish after opening.
  - Participants to include EOC Director/Manager, Potelco base managers and Puget Sound Energy Electric First Response supervisors.
  - Provide best available information & refine as new information available.
- Have a restoration plan – document it & communicate it.
- Utilize escalated call process.
- Focus on critical facility restoration prioritization (lists in Volume II).
- Open Whidbey Operating Base as a storm board as appropriate.
- Track resources (crews, assessors, servicemen, etc.)
- Establish local area coordination as needed to enhance restoration and customer communications.

Lodging Coordinator

Provide lodging coordination for regional operating bases, working with the Emergency Operations Center (EOC) to ensure adequate bed capacity for foreign crews and operating/storm base personnel. Manage local lodging arrangements (assign/track personnel and their lodging assignments) throughout emergency event. Coordinate with the EOC to request added lodging locations when additional beds are not available at locations already arranged by the EOC. Coordinate with hotel staff to arrange net additions/reductions in beds as needed throughout event, including providing hotel staff lists of personnel assigned to each facility, number of nights for each room, etc. Work with hotel staff as necessary to resolve lodging issues. Track and provide regular updates to the EOC on lodging utilization throughout the event.

PSE Liaison – County/City EOC(s)

Represent Puget Sound Energy (PSE) at assigned County or City Emergency Operations Centers (EOCs). Serve as liaison and focal point for communications between County EOC staff and PSE. Provide routine updates to County EOC staff on impacts to PSE's energy distribution system(s) and current restoration timelines. Identify key coordination issues between PSE and County (public works, police/fire, roads, parks, transit) DOT or Telco's and facilitate discussions to resolve. Collaborate with the Puget Suond Energy EOC and County Public Information Officers on community messaging. Coordinate with County staff to obtain additional resources if required. Participate in scheduled PSE conference calls. (City EOC's will be staffed on request of the jurisdiction for specific events affecting local areas. These requests are made to the Emergency Planning Manager or Manager Operations Continuity and will be staffed on an as needed basis.) Work schedules may vary, but are anticipated to be a minimum of 12-hour shifts during daytime hours, to be coordinated with the County EOCs.

PSE Liaison – State of WA EOC

Represent Puget Sound Energy at the State of Washington Emergency Operations Center (EOC), located at Camp Murray. Serve as liaison and focal point for communications between State of WA Emergency Management Division (EMD) staff and PSE. Provide routine updates to State of WA EMD staff on impacts to PSE's energy distribution system(s) and current restoration timeline. Identify key coordination issues between PSE and State of WA and facilitate discussions to resolve. Coordinate with appropriate State agencies to obtain temporary rules exemptions where restrictive regulation may adversely affect response efforts. Coordinate with EMD staff to obtain additional resources, as required. Work schedules may vary, but are anticipated to be a minimum of 12-hour shifts during daytime hours, to be coordinated with the State EOC.

5.4.1

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6.4.1

Conner, Kathryn

ıbject:	Damage Assessor Training
‿ocation:	Kitsap Service Center, 2nd Floor Conf Room
Start:	Tue 8/14/2007 9:00 AM
End:	Tue 8/14/2007 4:00 PM
Show Time As:	Free
Recurrence:	(none)
Meeting Status:	Meeting organizer
Required Attendees:	[redacted]
Optional Attendees:	

This training is mandatory, so please make every effort to attend. All supervisors have been apprised of mandatory storm duty training.

Lunch will be served.

Kitsap Service Center is located at 6522 Kitsap Way, Bremerton, WA.

Conner, Kathryn

ubject:	Damage Assessor Training
Location:	S. King Service Center, Conf Rooms 1-2-3
Start:	Mon 8/13/2007 9:00 AM
End:	Mon 8/13/2007 4:00 PM
Show Time As:	Free
Recurrence:	(none)
Meeting Status:	Meeting organizer
Required Attendees:	[redacted]
Optional Attendees:	

This training is mandatory, so please make every effort to attend. All supervisors have been apprised of mandatory storm duty training.

Lunch will be served.

e South King Service Center is located at: 6905 S. 228th Street, Kent, WA 98032.

Conner, Kathryn

`ubject: Damage Assessor Training
_ocation: Conf EST05E49 - Issaquah - 20 (Restricted Access - Escort Req.)

Start: Thu 8/9/2007 9:00 AM
End: Thu 8/9/2007 4:00 PM
Show Time As: Free

Recurrence: (none)

Meeting Status: Meeting organizer

Required Attendees: [redacted]

Optional Attendees: [redacted]

UPDATED: THIS MEETING WILL BE HELD IN THE FORUM - 1ST FLOOR MEETING ROOM IN EST BLDG.

This training is mandatory, so please make every effort to attend. All supervisors have been apprised of mandatory storm duty training.

ınch will be served.

Conner, Kathryn

Subject:	Damage Assessor Training
Location:	Tacoma Svc Center, Tacoma Conf Room
Start:	Tue 8/7/2007 9:00 AM
End:	Tue 8/7/2007 4:00 PM
Show Time As:	Free
Recurrence:	(none)
Meeting Status:	Meeting organizer
Required Attendees:	[redacted]
Optional Attendees:	[redacted]

This training is mandatory, so please make every effort to attend. Supervisors have been apprised of this training.

Lunch will be served.

Location for Tacoma Service Center:

130 South 38 Street
Tacoma, WA

Conner, Kathryn

Subject:	Damage Assessor Training
Location:	The Forum, EST Bldg, 1st Floor
Start:	Mon 8/6/2007 9:00 AM
End:	Mon 8/6/2007 4:00 PM
Show Time As:	Free
Recurrence:	(none)
Meeting Status:	Meeting organizer
Required Attendees:	[redacted]
Optional Attendees:	[redacted]

This training is mandatory, so please make every effort to attend. All supervisors have been apprised of mandatory storm duty training.

Lunch will be served.

Conner, Kathryn

Subject: Damage Assessor Training
Location: The Forum, EST Bldg, 1st Floor

Start: Fri 8/3/2007 9:00 AM
End: Fri 8/3/2007 4:00 PM

Recurrence: (none)

Meeting Status: Meeting organizer

Required Attendees: [redacted]

Optional Attendees: [redacted]

Attendance at this meeting is mandatory, please make every effort to attend. Supervisors have been previously apprised of this required training.

Lunch will be served.

Conner, Kathryn

Subject: Damage Assessor Training
Location: Mt Vernon Conf Room

Start: Tue 7/31/2007 9:00 AM
End: Tue 7/31/2007 5:00 PM
Show Time As: Free

Recurrence: (none)

Meeting Status: Meeting organizer

Required Attendees: [redacted]

Optional Attendees: [redacted]

Updated: This training class is supposed to run from 9 to 4.

This training is mandatory and supervisors have been apprised of this. Please make every attempt to attend this training. Lunch will be served.

The address for the Mt Vernon office is:

Mt. Vernon Customer Construction
1700 E College Way
Mt. Vernon, WA 98273

6.4.1-B

2007 Damage Assessor Training

Mark Wesolowski and Associates

The KEMA Report

- Consultant hired by PSE to review performance during December windstorm
- Performed well restoring power after the record-breaking storm
- No formal or informal means of evaluating how well attendees learned D/A skills
- Basic skill requirements for the D/A do not appear to be formally defined

KEMA Recommendations

- Enhance D/A training through more detailed technical content, extended training time, & qualifications screening
- Revise the D/A process to include specific methods for restoration times and manpower requirements
- Formalize the information requirements and process for D/A's in the field

This Year's Training….

- Covers a lot of the basics for newcomers
- Is a good review for "seasoned" D/A's
- Introduces a new D/A Guide
- Covers the revised D/A form
- Emphasizes the need for detailed materials required lists

Three Parts to the Training

- **Part One:** Duties, Responsibilities, Safety, Flagging, Equipment, Environmental, and Mapping (including a map reading exercise)
- **Part Two:** System Components
- **Part Three:** New D/A Guide, New D/A Form

The Final Test

- A practical application consisting of five scenarios to test your knowledge and skills

Housekeeping Issues

- Sign the roster, but…..
- Cell phones/Blackberries – please turn ringers off and put on "vibrate"
- Please do not handle e-mail and text message while in class
- Breaks – we'll take a couple – keep them short, and we'll be done sooner!
- Lunch – will be provided

THIS JUST IN…..

- PSE will conduct a Mock Storm on September 5th
- Will be company-wide
- You might be called out to "damage assess" an area

PART ONE

Duties, Responsibilities, Safety, Flagging, Equipment, Mapping, Environmental

What is Damage Assessment?

- Causes of damage:
  - Wind, floods, ice, earthquake, snow
- Minor events
  - System Operations manages event
  - Damage Assessment handled by EFR
  - EFR may call out Damage Assessors
- Medium to large events
  - Operating Base opens
  - EOC might open
  - Damage Assessment teams deployed

What's left of a pole

(Photo by Jeff Tripp)

The top end……

(Photo by Jeff Tripp)

Check In/Out

- When called out for Damage Assessment duty, unless directed otherwise, report to the operating base as instructed
- You may first have to pick up a pool car
- Check in at the operating base when you arrive for duty and ***sign in*** on the sign in sheet
- When going home, be sure to let someone at the operating base know and ***sign out***

Damage Assessor Duties

- Reports to the Damage Assessment Coordinator
- May work as a single team or part of a larger area team working with an Area Coordinator
- Storm base will make assignments
- Work as a team member with a Driver

Regarding Drivers

- May or may not have D/A experience
- You are focused on looking for damage;
- Your driver should watch the road
- Outline your expectations of the driver
- (Drivers will have separate training)

Representative of PSE

- You are representing PSE in the field
- Wear your hard hat, vest, and/or other PSE logo'd apparel
- **DO NOT** give estimates on restoration times!!! (Usually these early estimates are not accurate and the customers can become upset)

Working Conditions

- May be working around other crews (city, tree, other utility, etc)
- Long hours in bad weather
- Could be away from home for several days
- Spend many hours on your feet, generally out in the weather

SAFETY FIRST!

- Your number one objective is to stay safe while Damage Assessing!
- If wind picks up, return to operating base
- Required safety equipment:
  - Hard Hat
  - Reflective Vest
  - Safety Glasses

FIELD SAFETY

- **<u>DO NOT CONTACT DOWNED LINES!</u>**
- Stay away from all downed lines
  - Protect yourself
  - Protect the public
  - Mark area (***<u>not</u>*** the conductor) with special tape or cones
- Tree wire looks like CATV or phone wire
- If it's not grounded, it's not dead!

REPORTING EMERGENCIES

- Wire down and burning – contact EFR dispatcher – stay on site if necessary
- Medical/Injury – dial 911
- Other (need crew quickly) – contact operating base
  - Pole/low wire in busy road

Field Safety
(continued…)

- Drive properly, follow all traffic laws; You are **<u>NOT</u>** an emergency vehicle
- Use caution when walking through yards – wear your hard hat and vest
- Be aware of the hazards of cold
- Be aware of falling debris and trees
- Poles and trees may appear down, but may move unexpectedly – stay clear!

Field Safety
(continued…)

- Watch your footing
- Be aware of traffic; cones can't stop cars
- Be ALERT in work areas
- Never remove or tamper with tags
- Note on the D/A form if upstream fused c/o's are closed and notify operating base

Personal Necessities

- Medication/Prescriptions
- Extra glasses
- Toothbrush
- Money
- Cell Phone/Charger
- Extra Clothing
- Rain Gear
- Water
- Snacks/Food

- **PLAN ON NOT BEING ABLE TO BUY ANYTHING IN THE FIELD!**

A Personal Storm Bag….

Storm Bag Contents…..

Storm Equipment

- PSE will furnish storm bags containing:
  - 3 Cell Flashlight
  - 6 Pack "D" Cell Batteries
  - Battery Operated Strobe Light
  - Spot Light (plug into cigarette lighter only)
  - Roll of Caution Tape
  - 3 Way 12v Outlet
  - Spiral Note Pad
  - Clipboard
  - Circuit Maps and local (Thomas Brothers) maps

Storm Equipment (continued)

- Storm Bag, continued:
  - 12 Pack 3" Yellow Sticky Note Pads
  - Set of 3 Color Ball Point Pens
  - Set of 4 Color Permanent Markers
  - 50 Pack Storm Damage Tags
  - Pad of Damage Assessment Forms
  - Pad of Oil Spill Forms
  - Pad of Pole/Xfmr Replacement Forms
  - And some CCC stuff (tags, forms, etc)
- Storm bag is also used for CCC's

GPS Units

- GPS units may be available at the storm base
- Or if you have one from your department, please bring it.

Return Equipment!

- Take your storm equipment bag and unused supplies back to the storm base
- Return your GPS unit
- You may keep your D/A Guide

On the job….

Photo by Jeff Tripp

Your Mission

- Eyes in the field
- Fill out Damage Assessment forms
- Communicate Damage Assessment info back to storm base:
  - You might be calling the assessment information in – do so from that site
  - Or you might be delivering completed forms to the storm base
  - Report damage frequently

The Operating Base Needs…

- Early and frequent reports ("snapshots") so they can get a handle on the severity and start arranging resources
- To know of any unusual, involved jobs, such as double circuit or very involved corner poles, tree crews needed, etc
- More detail of needed materials for repairs (more on that later)

Where To Start?

- Unless directed otherwise, start at the substation
- Patrol the whole feeder first
- Then patrol laterals

Where Am I?

- Location, Location, Location:
  - Address on a mailbox or house
  - Nearest intersection
  - Notable landmark
  - Pole number or grid number
  - Switch number
  - The more information provided, the better!

How To Access Site?

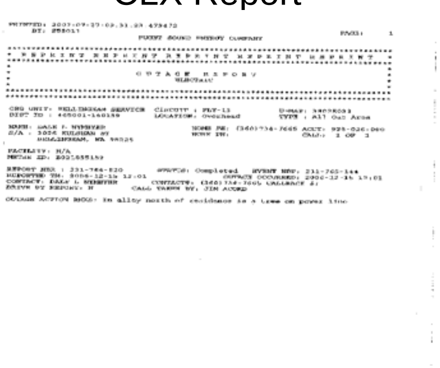
- Easy to get to, on a street or road?
- Or:
  - Roads washed out?
  - Trees across road?
  - Walk-in location?
  - Any special directions needed?

Tree Crews

Photo by Jeff Tripp

- Generally lots of tree crews available
- Call in early if obvious a tree crew is needed for access
- Line crews can do some limited tree work

CLX Report



CLX Report

CLX Report

CLX Report

Map Reading Exercise

- Find address on Thomas Brothers map
- (Include page and grid number)
- Determine appropriate circuit map
- Find location on circuit map
- Determine which circuit
- Identify protective device

How About Traffic Control?

- Are flaggers needed?
- If so, how many (two? three?) Consider:
  - Does the road curve?
  - Is there a hill involved?
  - Is there a 3-way or more intersection?

You never know who might show up to be your flagger….

(Photo by Jeff Tripp)

Environmental

- Any oil spilled?
- Transite pipe on pole (riser)?

(either must be reported immediately)

Oil Spill……

(photo by Jeff Tripp)

- An example of transite pipe is available, wrapped in clear plastic, to see if you are not familiar with what it looks like. Come up and look at it at the break.

BREAK

PART TWO

System Components

System Components

- Poles
- Crossarms
- Transformers
- Insulators
- Wire
- Switches
- Fuses
- Terminations
- Guy Wires
- Cell Net
- Other Equipment
  - Regulators
  - Reclosers
  - Sectionalizers
  - Line Capacitors

Poles

- Two factors – length and class
- How do I find out the length/class?
  - Look at the pole tag in the pole gain
  - Look at adjacent pole(s)

Pole Tags

Crossarms

- Distribution Sizes range from 9 – 13 feet
  - 9 foot arms (most common) use flat braces
  - 11 foot arms use “Vee” braces
  - 13 foot arms are used for double circuits
- Fiberglass arms for compact construction
  - Replace older steel short arms with fiberglass arms
- Replace single phase arms with pole top pins and neutral in common position, if possible

Transformers

- Single and Two Bushings
- kVA rating on side of xfmr
- In most cases, a single phase xfmr can replace a two bushing xfmr

Insulators

- Insulators on steel (wood) pins
- Dead end type bells
- Rigid clevis
- Strain insulators

Wire

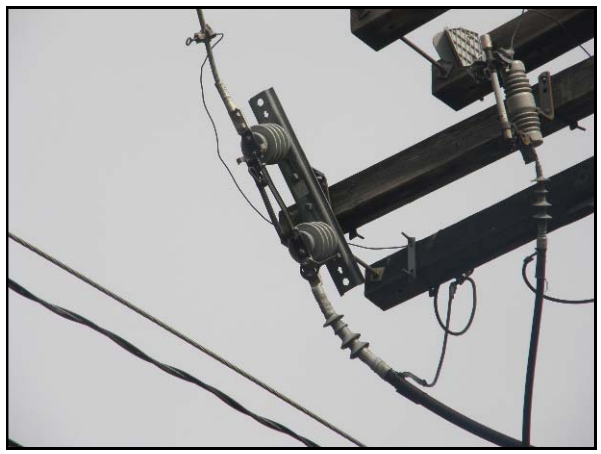
- Type
  - Copper
  - ACSR
  - AAC (looks like ACSR)
- Size
  - #6 – 4/0 Copper
  - 1/0 – 4/0 and 336 and 397mcm ACSR
- Service Wire
  - Triplex – #2, 1/0, 4/0
- Tree Wire

Switches

- Gang Operated
  - With operating handle
- Solid Blade Disconnects
  - Load Break or Non-Load Break

Gang Op Switch

Solid Blade Disconnects



Fuses

- Three phase taps
- Laterals
- Occasionally fuses are found in the primary feeder, usually with bypass disconnects

Fused Cut Outs

Regulators

- Usually single phase, mounted on poles
- Occasionally platform mounted 3-phase

Reclosers

- Two types
  - Oil-filled
  - Vacuum type

Sectionalizers

- Looks like a small oil-filled recloser

Line Capacitors

- Square cans mounted in a rack on pole, usually three, with fuses
- If ruptured or leaking, treat as an oil spill

Cell Net

Other Stuff on a Pole

- Telephone
- Cable
- Fiber Optic

What about…..

- Street Lights?
  - Into Light number on pole?
- Cell Net Equipment?
  - Number on box?
- Raptor Protection?
  - Reusable?

- Note these items on D/A form

BREAK FOR LUNCH

PART THREE

D/A Guide
D/A Form
Final Test

Damage Assessment Guide

- Covers the basics
- Images of system components
- Lists of materials by MID for basic units
  - Storerooms need complete lists of materials
  - Use MID if you can
  - A "pole" gets you a "pole" – nothing else!
  - Use back of D/A form to list materials

Damage Assessment Form

- Revised form
- Easier to use
- A number of folks contributed suggestions
- Review form with students
- Fill out as completely as possible


PUGET SOUND ENERGY
DAMAGE ASSESSMENT

FINAL EXAM

- Five Scenarios
- Complete a D/A form for each scenario

7.4.1

PUGET SOUND ENERGY

Storm Base Expectations for 2007-08

- "Own it"
- Storm Levels (1, 2, or 3) will be declared *(see attachment)*.
- "Windshield" assessment in each region within 24 hours.
    - Goal: area specific estimated restoration times within 48-72 hours of event subsiding.
- Focus on critical facility restoration prioritization (lists in Volume II).
- Create restoration plan - document it & communicate it.
- Commitment to estimated restoration times communicated to customers.
- Operations conference calls 2X/day (suggested at shift changes):
    - EOC to establish after opening.
    - Participants to include EOC Director/Manager, Potelco base managers and PSE EFR supervisors.
    - Provide best available information & refine as new information available.
- Track resources (crews, assessors, servicemen, etc.)
- Establish local area coordination as needed to enhance restoration and customer communications.
- Open Whidbey Operating Base as a storm board as appropriate.
- Utilize escalated call process.

7.4.1-B

VOLUME 2 **2007-2008**

CORPORATE EMERGENCY RESPONSE PLAN





PSE PUGET SOUND ENERGY
The Energy To Do Great Things

Emergency Response Roles – Electric

This section describes the positions and job duties at EOC during electric facility failures and positions at Quanta Operating Bases for electric emergency response. The Corporate EOC is headquartered at Eastside Operations – Redmond.

EOC Roles

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Corporate EOC	EOC Director	The EOC director provides Corporate (strategic) oversight and financial authority to response efforts. Once the EOC is opened, the Director becomes the information focal point for the executive management team and may respond to media inquiries about emergency response activities as needed by Corporate Communications.	Emergency Response Overview; EOC Orientation
	EOC Manager	Coordinates opening of the EOC and determines level of response required for each emergency. Coordinates with Quanta EOC Duty Manager to obtain resources needed for restoration. Balances available resources against system damage and realigns overall efforts when estimated restoration times are significantly skewed between regions. Oversees overall event reporting and ensures periodic detailed reports are issued.	Emergency Response Overview; EOC Orientation
	Quanta EOC Duty Manager	Works with Puget Sound Energy EOC Director and Manager to acquire resources needed for emergency events. Ensures Quanta resources for crews, damage assessors, CLX data entry personnel, etc. are trained and qualified for emergency response functions. Coordinates movement of Quanta regional resources and out-of-area crews that may be required for major events including equipment, fleet, travel and accommodations. Requests additional resources from PSE EOC Manager as required to augment operating base personnel; e.g., damage assessors, crew coordinators, drivers, CLX information specialists, crew supervisors, etc.	Emergency Response Overview; EOC Orientation
	EOC Communications Coordinator	Coordinates with EOC Director and Manager to ensure timely and accurate communications with the media. Coordinates messaging with Operations, Access Center and regional Communications Coordinators to ensure that restoration information is consistent across all communications channels.	Emergency Response Overview

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Corporate EOC	EMS Analyst	Assesses system damage through electronic sensors located in substations and along major transmission lines (SCADA, EMS, DMS) and provides information. Focuses primarily on providing outage information at the substation and transmission line level. Ensures transmission, substation status information is communicated to storm boards	Emergency Response Overview EMS Training
	I/T Manager	Responsible to provide resolution oversight to reported hardware, application, network or key interface issues. Coordinates with PSE's helpdesk, network, application and desktop personnel to assure failures are quickly resolved or appropriately escalated, ensuring mission-critical technology tools are returned to service a soon as may be practicable.	Emergency Response Overview
	Manager Electric First Response	Works with Quanta EOC Duty Manager, PSE EOC Manager, On-duty System Operations Supervisor and PSE First Response Supervisors. Coordinates company-wide first-response resource allocation including decisions to move first response servicemen out of area, etc.	Emergency Response Overview
	Resource Coordinator	Assists in the allocation and retention of resources as required by field operations including assessors, additional crews, flaggers, etc. Works with Quanta EOC Duty Manager to ensure adequate crew availability and may call out and assign non-Quanta, off-system, out-of-state, and/or mutual assistance utility crews. May also call out specialty contractors (flagging, tree removal, helicopter and environmental, etc.) as required by PSE and Quanta for service restoration. Make arrangements for border crossings, ferry travel, and emergency road openings as required. Tracks foreign and contract crews as they change locations within PSE's service territory.	Emergency Response Overview

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Corporate EOC	Data Specialist	An outage data expert. Familiar with CLX and AMR outage tools. Tracks progression of outages and customer calls; archives history of event at regular intervals. May also perform DDD analysis.	Emergency Response Overview; EOC Orientation
	Administrative Support	Obtains and organizes periodic detailed reports for each impacted area and collates into regular updates for internal audiences such as, customer service, Corp Communications and, external audiences such as, State / County / City EOC's and American Red Cross.	Emergency Response Overview
	911 Call Taker	Answers emergency calls from 911 agencies, police, etc. reporting downed wire, fires, and blocked right-of-ways. Enters reported information into CLX, ensuring priority outage reports are sent to Quanta operating bases.	Emergency Response Overview; 911 Call Taker Training
	On-duty System Operations Supervisor	A regularly staffed PSE position responsible for initiating the emergency response. Also responsible for: Monitoring weather and regularly communicating with PSE staff and Quanta field operations. Notifying Quanta management and EOC duty management to activate emergency response plans. Monitoring emergency event escalation, restoration efforts and overall recovery of the electric system.	Emergency Response Overview

Operating Base Roles

These functions are performed by Quanta and/or PSE employees:

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Quanta Operating Base	Storm Manager	Directs or manages area storm operations, emergency response assignments, assessment, and restoration. Primary contact person with EOC, System Operations, Substations, Transmission, and Access Center. Assesses needs for additional resources, coordinating with EOC for external resources and assistance as required. Coordinates with the Damage Coordinator, Crew Coordinator and EOC to prioritize restoration activities.	Emergency Response Overview; CLX Outage Management
	First Response Supervisor	Provides support for Quanta Operating Base Manager as required. Supervises and monitors local area first responders (servicemen) and electric dispatchers to ensure adequate response. Reassigns first responders for service restoration and damage assessment as appropriate. Provides Corporate EOC with information as requested. May act as Operating Base Manager for shift coverage as require	Emergency Response Overview; CLX Outage Management
	Storm Board Coordinator	Reports to the Quanta Storm Manager. Analyzes outages and tracks needed repairs and location of assigned resources. Receives information from servicemen, CLX, 911 call-takers, damage assessors and others on location. Packages damage information by area for efficient restoration. Reviews / prioritizes response to emergencies reported via 911 agencies.	Emergency Response Overview; CLX Outage Management

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Quanta Operating Base	Storm Board Analyst	Assists the Support Storm Board to coordinate and prioritize restoration and identify circuits. Provides DDD and EMS expertise as required; e.g., sub-circuiting outages for CLX. Assists CLX data entry process to ensure customer system updated accurately and timely. Works with Damage Coordinator to determine damage assessment needs and coordinate damage assessors for the designated area.	Emergency Response Overview; CLX Outage Management; DDD and or EMS
	Storm Board Assistant	Provides support to Storm Board coordinator. Reviews available outage information and records emergency. Assists in prioritizing work and communicates assignments to damage assessors, electric dispatcher and crew coordinator. Updates Storm Board and ensures CLX reflects current status. Assists with analysis and prioritizing of emergencies reported via 911 agencies.	Emergency Response Overview
	Damage Assessment Coordinator	Reports to the Quanta Storm Manager Oversees and coordinates the damage assessment and restoration prioritization for the operating base. Manages and assigns qualified personnel to damage assessment duties. Ensures the Storm Boards are updated and that CLX updates are consistent, timely and accurate. Assists in prioritizing restoration efforts. Communicates status and locations of assessment teams within the area. Coordinates with Storm Board management to prioritize restoration activities	Emergency Response Overview; CLX Outage Management; Damage Assessment Training
	Damage Assessor	Reports to the Damage Assessment Coordinator. Assesses system damage in designated areas. Records damage and material needs and relays the information to the Storm Board.	Emergency Response Overview; Damage Assessor Training

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Quanta Operating Base	Crew Coordinator (General Foreman)	Reports to the Quanta Storm Manager. Oversees the line crew restoration effort throughout the event. Ensures field resources are deployed efficiently for safe and timely restoration. Coordinates with the Emergency Response Manager and Damage Coordinator to prioritize restoration.	Emergency Response Overview
	Service Dispatcher	Reports to PSE First Response Supervisor. Dispatches PSE Servicemen and Quanta two-person emergency crews to 911 calls, critical switching, patrolling, and secondary service restoration. May work with some autonomy early in event and later works in close coordination with storm board staff as event escalates and overall event management shifts to the storm board coordinator.	Emergency Response Overview; CLX Outage Management
	CLX Specialist	Updates CLX Outage Management information system regularly throughout the emergency to ensure prompt, accurate information to the Access Center and EOC.	Emergency Response Overview; CLX Outage Management
	Area Coordinator	From a remote location, using assigned resources, manages all restoration activity (damage assessment, restoration prioritization and related crew assignments) to restore extensively damaged areas. Assigned areas may be defined electrically, such as all circuits from specific substations or geographically using landmark boundaries.	Emergency Response Overview
	Contract Crew Coordinator	Reports to the Crew Coordinator (GF). Leads crews to damaged areas and works ahead of crews to see that effective restoration methods are being followed, material and other needs are met. Ensures "foreign" contract crew personnel are informed of required safety, construction and switching practice information.	Emergency Response Overview; Contract Crew Coordinator Training, First Aid

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Quanta Operating Base	Communications Coordinator	Works closely with local operating base management throughout the emergency to ensure that critical customer loads (e.g., healthcare, area shelter locations, etc.) are appropriately identified and prioritized for restoration. Monitors outages impacting Major and Business Accounts as well as specific customer groups or areas. Coordinates with the Media Representative in the EOC (or, corporate communications when the EOC is not open) to ensure that notifications and updates provided locally are consistent with messages issued through Corporate Communications and the Access Center. Responds to specific customer inquiries from major account or key business customers (e.g., schools, healthcare facilities, grocery store chains, etc.). Works with the Major Account Representative(s) in the EOC to coordinate major and key customer response. Provides information to local media, municipalities, and county emergency response departments (when the EOC is not open) on damage assessment and outage restoration efforts.	Emergency Response Overview
	Driver	Safely operates vehicle while Damage Assessor visually assesses and records circuit damage	Driver Training
	Make-it-Safe	Dispatched to locations where primary wire is reported to be down. Ensures site safety until qualified electrical workers are on-scene.	Emergency Response Overview; Make it Safe Training

7.4.2

PUGET SOUND ENERGY

For Internal Use Only

Storm Management Policy
10 October 2007

Local Area Coordination Plan

Key Words

Restoration

Purpose

The purpose of this document is to formalize the ad hoc practice used for several years in establishing local area coordination sites for restoration activities

Discussion

It has been a long-standing practice of Puget Sound Energy to establish local area coordination sites to assist with restoration activities during events where the magnitude of damage and crew work activity may overwhelm an open operating base. The functions performed at a local area coordination site are a sub-set of the storm base functions and are managed by a smaller team of qualified and experienced emergency response personnel. The purpose of this document is to institutionalize and document the considerations used in opening a local area coordination center, as well as to provide details for staffing, site selection and a checklist for resource needs and logistics.

Definitions

Local Area Coordination Site: A geographic sub-set of an operating base area of responsibility for the restoration of electrical service following a major emergency event. Functions performed by staff at a local area coordination center include communicating real time restoration activities to appropriate parties, managing all crew activities within the area assigned, analyzing and creating restoration strategies, coordinating with the Load Office, System Operations, the EOC and Operating Base. Materials used and any temporary repairs made in the area assigned are tracked and documented.

Procedures

Who	Does what
EOC and Operating Base	▪ Determine when and where to open a Local Area Coordination Site taking into consideration the following: o Status of completion of damage assessment in region o Knowledge of system damage (collecting area damage assessment from operating base manager and dispatcher) o Crew resource availability o Material availability o Qualified site management personnel availability o Weather forecast o Transportation challenges

Who	Does what
Operating Base	▪ Determines sites for establishing Local Area Coordination ▪ Assigns crews and crew work packets to Local Area Coordination Site Manager. ▪ Communicates to the EOC site location and estimated time work will be transferred to Site Manager.
EOC	▪ Provides logistics support assistance to Operating Base to establish Local Area Coordination Site (e.g., resources, materials, facility needs – tents, sanitation facilities, generator power, portable offices, computers, phones, maps, etc.). ▪ Receives information directly from Site Manager at Local Area Coordination Site and/or Operating Base Manager.
Site Manager	▪ Manages resources at Local Area Coordination Site. ▪ Communicates with the Operating Base and EOC ▪ Assigns team responsibilities: o System Coordinator: coordinate system restoration, communicate with Load Office, System Operations and Operating Base. May include responsibility for switching and clearances for area assigned. o Material Coordinator: distribute, procure and account for material usage. o Community Relations Manager: responsible for communicating with community in area and local media. o Logistics Coordinator: coordinate all facility needs. o Administration Support: provide all administrative support, including providing updates for CLX data entry at the Operating Base.

REFERENCES:

Appendix A: Local Area Coordination Site Location
Appendix B: Local Area Coordination Staffing Plan
Appendix C: Local Area Coordination Logistics - Checklist

Version	Draft SMP-04
Revision date	10 October 2007

Local Area Coordination APPENDIX A

Site Locations – DRAFT 10/10/2007

(NOTE: Location sites not owned by PSE – will need authorization by property owners for use as outage event staging areas.)

NORTHERN

Whatcom County

- Nugent's Corner Area - Lawrence Road (Highway 9) and Mt. Baker Highway - Church Parking Lot at intersection of Hadley and Lawrence Roads.

- Ferndale Area - Grandview and Portal Way (off I-5) - Salishan Parkway goes into business park (vast parking area).

- Grandview & Vista - Grange Hall.

- Lynden/Birch Bay Area - Outlet Mall off I-5.

- Lynden/Sumas Area - Verizon Service Base (used to be PSE Service Base) - at intersection of Badger Road and Depot Road.

Skagit County

- Conway Exit off I-5 - Shell Station - owner Gary Fidler (plenty of parking -graveled area across from station and one north of station).

- Conway Exit off I-5 - Graveled property that is west of the Shell Station at Conway - talked to State Hwy Dept Manager, Kim Glass, and he said property is owned by Seattle residents (brothers) who have allowed contractors in the past to utilize the property for staging projects. Mr. Glass didn't have their names, but I'm going to work through our Real Estate Dept to find the owners and contact them as soon as possible.

- Lower Baker Area - Large compound - discussed with Ron Twiner (Mgr Hydro Services North - cell 661-2280) and he'll will work with us on specific area.

- Alger Area - Alger Community Center - just off I-5.

- Lake Cavanaugh Area (because of communication issues may need it's own site) - Boat Launch has large parking area.

- Big Lake and South Skagit Hwy - County Park and Ride at the intersection of SR9 and South Skagit Hwy (never seems to be used that much).

- Big Lake and Little Mountain Area - Boat Launch on West Big Lake Blvd (would cover Big Lake, Little Mountain Area).

Site Locations continued...

- Anacortes Area - Burrows Bay Substation - in Anacortes - gives ability to cover Fidalgo and Guemes Island

Island County

- County Road Dept Shop - Supervisor Myron Gabelein - Location SR 525, Langley - working through Ray Trzynka, Corporate Communications, at this time due to sensitive issues for Whidbey Island.

- Brooks Hill Substation - addr 3450 Brooks Hill Rd., Langley - use for pole storage and other material - this is approximately 3 miles from the County Road Dept Shop.

- Green Bank Substation - right off Hwy 525 located midway between north and south end of Whidbey Island - large grassy area in back of the substation.

NORTH KING

RENTON:
Shuffleton - PSE
Lake Washington Boulevard N & NE Park Drive

MERCER ISLAND:
Shopping Center - South End
SE 68 ST & 84 Ave SE

BELLEVUE:
Factoria - PSE
13230 SE 32 ST

KIRKLAND:(Juanita/Finn Hill)
Bastyr University - Athletic Fields
NE 145 ST & Juanita Drive NE

REDMOND:
Redmond - PSE
18150 Redmond Way

REDMOND:
King County Marymoor Park
NE 65 ST & 176 Ave NE

WOODINVILLE:
Shopping Center - (behind)
Woodinville-Duvall Rd NE & Avondale Rd NE

Site Locations continued...

ISSAQUAH:
Lake Sammamish State Park
NW Sammamish Rd & 15th Place NW

SAMMAMISH:
South Sammamish Park & Ride
SE 30 ST & 228 Ave SE

DUVALL:
Shopping Center
NE Big Rock Rd & Carnation-Duvall Rd NE

CARNATION:
Tolt McDonald Park
NE 40 ST & Fall City-Carnation Rd NE

SNOQUALMIE:
Centennial Park
SE Park St & Meadowbrook Slough

Kittitas County
South Cle Elum toward Easton
Cle Elum Sub with adjacent pole yard and city park
Jack and Main St S
Cle Elum WA 98922

Roslyn/Ronald/Cle Elum area
Cascade sub adjacent to BPA ROW and CleElum High School
1980 SR 903
Cle elum Wa 98922

Kittitas area (owner/operators Steve and Brenda Hart)
Exit 115 mini mart (gas station)
I-90 interchange
Kittitas 98924
(Brenda is a PSE employee and I have not yet had chance to get permission)

Easton
Parkside Cafe (adjacent parking lot gas station camping sites)
2560 Sparks Rd
Easton Wa 98925
(permission has not been requested)

Site Locations continued...

<u>SOUTH KING</u>

Enumclaw Line Headquarters
44720 – 244the Ave SE

Berrydale Substation
6905 – S. 228th
24810 – 156th Ave SE, Kent

Kent
South King Service Center
6905 – S. 228th St., Kent

<u>SOUTHERN</u>

Pierce County
White River Transmission Station
2111 – 169th Ave E, Sumner

Frederickson Transmission Station
Tacoma Industrial Park (E. of Spanaway, Spanaway

Orting Substation
504 Calistoga Ave, Orting

Kapowsin Substation
14321 Kapowsin Highway E, Kapowsin

Gravelly Lake Substation
8304 Washington Blvd., Lakewood

Thurston County
Yelm Substation
Railroad & Middle Streets, Yelm

Blumaer Substation
Hodgedon & Garfield St., Tenino

Rochester Substation
Intersection of Sargent Rd. & Township Rd.,
(183rd Ave SW), Rochester

Griffin Substation
6230 – 41st Avenue NW 9@ Steamboat Island Rd), Olympia

Site Locations continued...

Luhr Beach Substation
46th Ave NE & Meridian, Olympia

Saint Clair Substation
9512 Pacific Highway SE, Lacey

WESTERN

The Operating Base
Pt. Townsend Area

Kingston/Hansville Area
Mall area parking lot
Hwy. 104 & Hansville Rd.

Poulsbo Area
Poulsbo Operating Base with large staging area cross Hwy. 3
22884 Ryen Dr NW, Poulsbo

Bainbridge Area
Murden Cove Substation
9560 Sportsman Club Road, Bainbridge Island

Bremerton Area: Kitsap Operating Base
6522 Kitsap Way, Bremerton

Pt. Orchard Area
Saint Clair Substation, Large area outside the Substation
9512 Pacific Highway SE, Lacey

Local Area Coordination APPENDIX B

Staffing Plan

Names of PSE employees and retirees have been identified to possess the skills and experience to staff each of the following positions at a Local Area Coordination Site.

The Appendix B with names is protected for internal use only and may be found in the PSE EOC in Volume II of the Corporate Emergency Response Plan.

Local Area Coordination APPENDIX C

Site Checklist

Checklist Item	Completed ?	Notes/Who/Location
Site Location		
Staffing:		
Site Manager	________	________
System Coordinator	________	________
Material Coordinator	________	________
Community Relations	________	________
Logistics Coordinator	________	________
Admin. Support	________	________
Logistics:		
Porta Potties		
Security		
Tent		
Trailer		
Showers		
Food		
Water		
Supplies:		
Company Radio(s)		
First Aid Kit(s)		
Storm Bags		
White Boards/Pens		
Generator		
Fuel		
Extension Cord(s)		
Heater		
Lights		
Tables/Chairs		
Phones/Chargers		
Laptop		
Misc. Office Supplies		
Circuit Maps		
Material		

Rev. 10 October 2007

Rec. # 22 & 25 **Local Area Coordination Clearance Procedures**

Rev. 9/27/07

In designated areas where teams have been assigned to place a more localized focus to enhance restoration efforts, the following process enhancements are recommended.

- To maintain continuity of information, coordination and collaboration it is recommended that when possible, a dedicated system operator be assigned to work with the area coordination and restoration team/s. (Likely the Day Operator) To maintain continuity, key stakeholder schedules will need to be synchronized accordingly. (Staff up during productive hours and staff down during rest periods)
- Broader area clearances will be issued on the feeder system where possible. This should allow multiple crews to work under one clearance holder more frequently.
- Self-protection clearances will be encouraged on radial fed system where eligible.

PUGET SOUND ENERGY

Storm Management Policy
06 November 2007

For Internal Use Only

Transmission Restoration Team

Key Words

Transmission Outage

Purpose

The purpose of this document is to formalize a process of centralizing all transmission restoration and prioritization of that restoration when major damage has occurred to the transmission system during a weather-related or other event. This plan covers the restoration of all of PSE's 115Kv and 230Kv high voltage transmission lines.

Discussion

Puget Sound Energy restores facilities so that the greatest numbers of customers are back in service in the least amount of time; however, in events with significant damage to the transmission system, restoration of transmission must be coordinated with the Load Office, System Operations and the Operating Bases to ensure stability of the system. During the December 2006 major windstorm, transmission restoration decisions were centralized out of the EOC by a team called the "T-Pod". In after action reviews it was determined that the creation of such a transmission restoration team was a best practice that should be incorporated into PSE's corporate emergency response plans, particularly for major events where there are significant transmission outages

Definitions

Transmission Only Line Outages: transmission only line outages have no customers out on line; however may be critical for restoration for system stability.

Procedures

Who	Does what
Load Office	▪ When transmission outages company-wide are 5 or fewer, control all transmission patrol and repair, coordinating with the Operating Base.
EOC and Load Office	▪ When transmission outages are significant, the EOC is open and the Load Office requests assistance, the EOC will assign an individual to the EOC to work as a Transmission Liaison.
Transmission Liaison	▪ Responsible to maintain communications between the Load Office and the Operating Bases, coordinate priorities for repair, and keep the Load Office and EOC apprised of restoration progress and estimated restoration times. ▪ Coordinate and communicate with the EOC "EMS Engineer" who is also in communications with the Operating Bases, providing information on transmission restoration plans and estimates.
EOC Manager, Load Office Manager and Service Provider EOC Manager	▪ When the Transmission Liaison requests assistance, meet and determine if the Transmission Restoration Team should be activated. ▪ Identify and notify team members from both PSE and Service Provider.

Who	Does what
Transmission Restoration Team (TRT)	▪ Activate team activities in designated location at Eastside System Operations (10/2007 – training room in basement, above Load Office; old EOC location) ▪ Staff the team 24X7 until deactivation with qualified transmission experienced operations employees, and at least 1 full time administrative assistant ▪ Assign roles ▪ Maintain communication with the Operating Base(s) as to the status of the system repairs and the priority of the repairs. (This allows the operating bases to direct distribution crew repairs to the substation circuits that will be energized first) Communication may be via telephone, email or other. Options may include IT based solutions such as monitors at the Operating Bases and the EOC that show the status of the transmission system, which lines are out, affected substations, status of repairs and estimated completion of repairs. ▪ Work closely with the EOC EMS engineers the Load Office to track all outages and repairs to the system. Responsible to maintain the priority of repairs and to schedule all damage assessments of the transmission system. ▪ NOTE: Prioritization of lines to be restored continues to be the responsibility of the Load Office, supported by the EOC EMS engineers.
Operating Base	▪ Establish contact person for the transmission system with responsibility to maintain contact with the TRT ▪ Transfer control of transmission repair to the Transmission Restoration Team (TRT) ▪ Reassign working crews and damage assessment teams to the TRT (Operating bases will not conduct any repairs on the transmission system once the TRT is activated and will relinquish control of any crews on current repairs.)

REFERENCES:

Load Office Procedure: Transmission Only Line Outages – No Customer Outages Patrol & Repair (dated February 26, 2007)

RESOURCE REQUIREMENTS FOR SITING TRANSMISSION RESTORATION TEAM (TRT):

- Dedicated space for up to 8 people
- Access to the EOC EMS Engineers
- System wide storm T-Line map board
- Phones – 4 minimum
- Computers – 3 minimum
- Dedicated printer
- Fax machine
- GPS coordinate mapping programs on terminals
- Radio with multiple channels to talk to helicopter patrols

Version	Draft SMP-05
Revision date	10 October 2007
Revision date	06 November 2007

8.4.1

8.4.1-A

PUGET SOUND ENERGY

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October 19, 2007

General Info: 1-888-225-5773

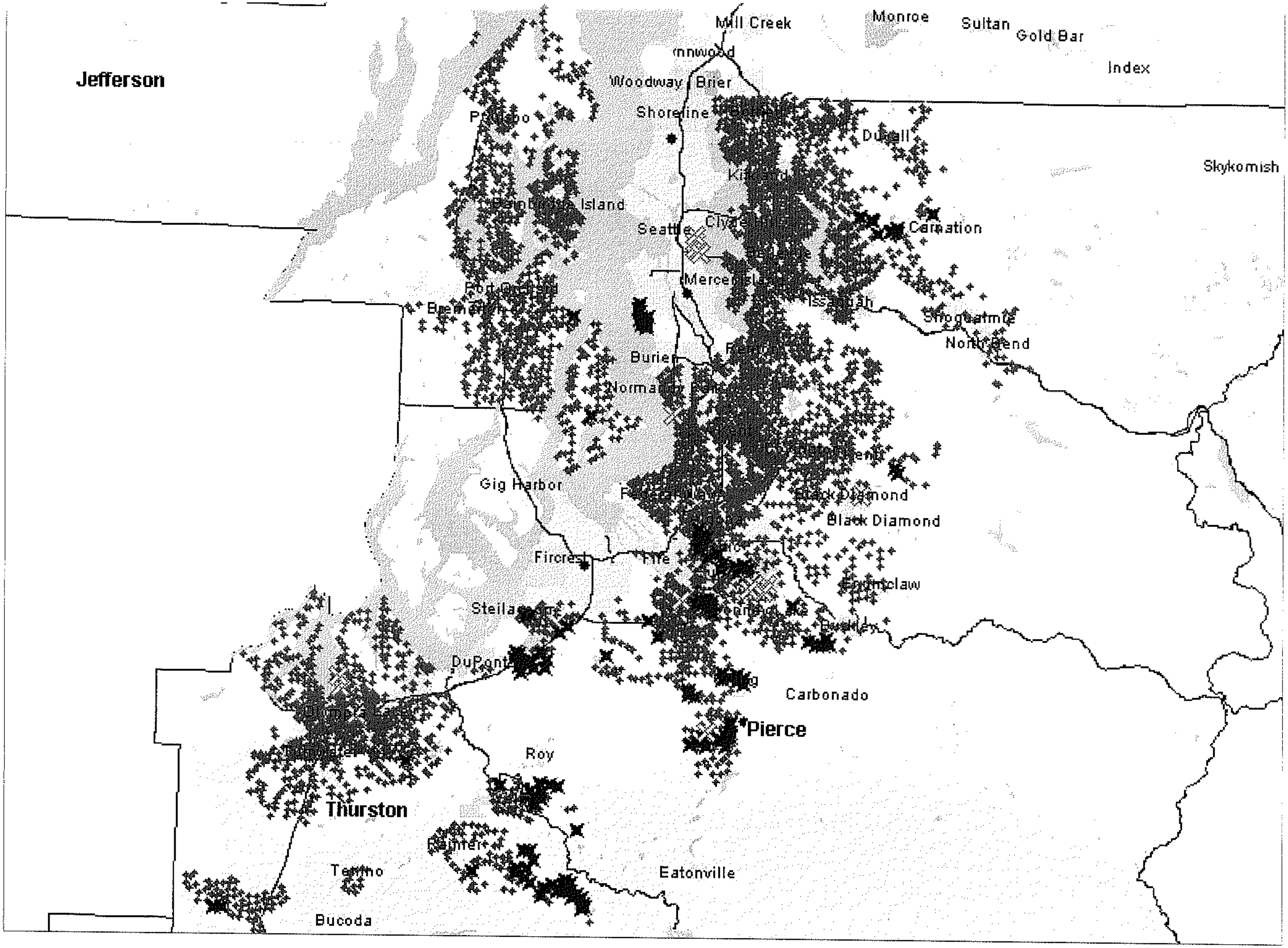
Latest Updates

KING and KIRO TV feature PSE storm preparations

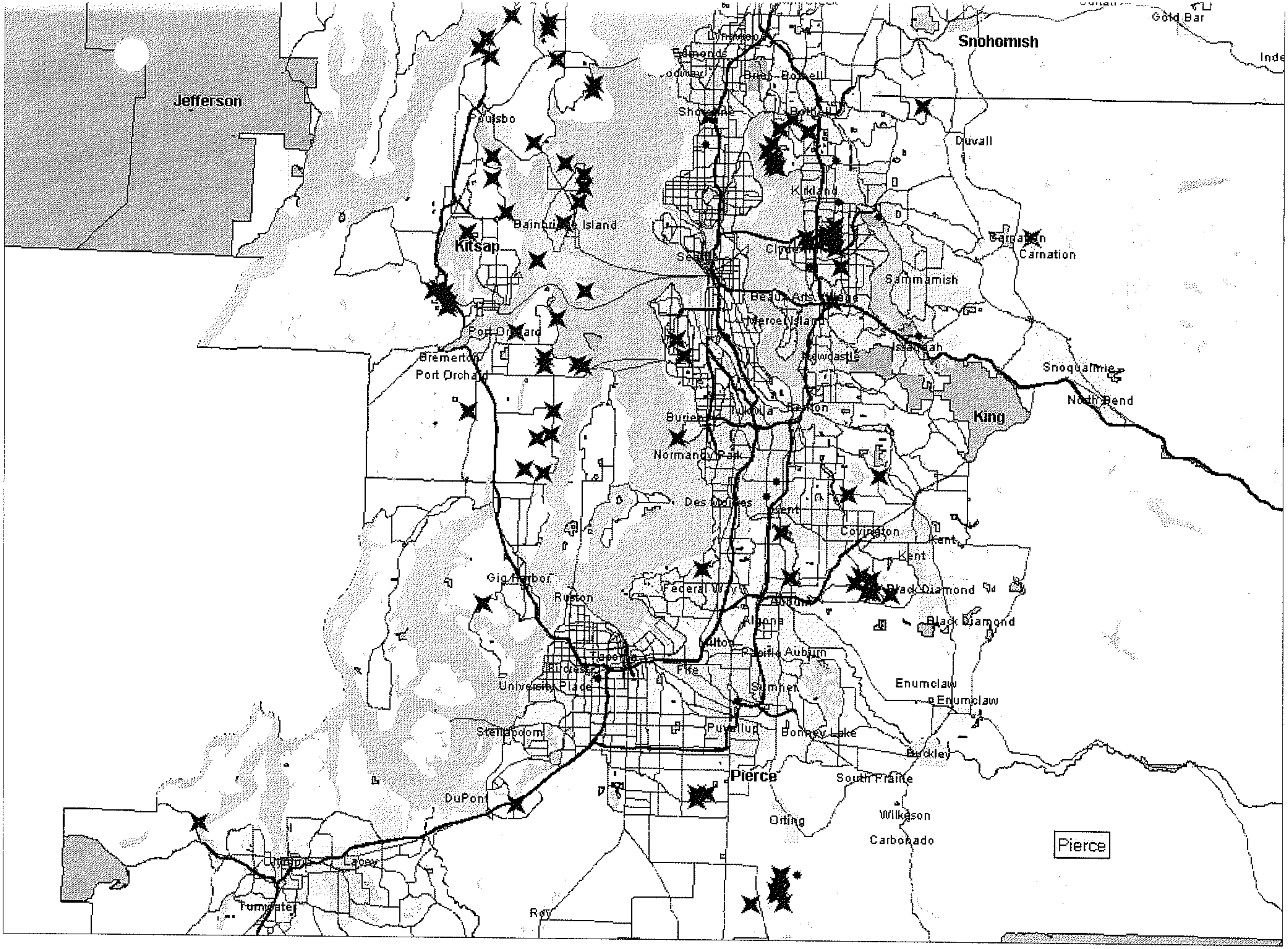
Watch video clips of news coverage: "PSE gets ready for the big wind storm" on KING-5 and "First big storm headed our way" on KIRO.

Service alert update 5 p.m. Oct. 18

- Puget Sound Energy is experiencing scattered power outages affecting thousands of customers in parts of Thurston, Pierce, King, Kitsap, and Island counties as a result of the strong winds hitting Western Washington.
- PSE crews have been in the field restoring power to several thousand customers since this morning, but with strong winds still blowing, new outages continue to occur and no estimate is available at this time on the total number of PSE customers who've lost power.
- Depending on how long the storm lasts and the extent of damage it causes, it is not possible yet to provide an accurate estimate of how long it will take to restore all our customers' service.
- PSE has approximately 80 line crews, together with about 50 tree crews and a full complement of damage-assessment crews, working to restore customers' power. In addition, another 35 to 40 outside line crews are available, if needed, to assist with power-restoration work.
- Within PSE's nine-county electric service area, gusty winds first hit south Puget Sound around midday today, causing scattered outages in Thurston and east Pierce County. Since then, the high winds have moved northward, with scattered outages now occurring in King and Kitsap counties.
- Anyone who encounters a downed power line should stay well clear of the line and call their electric utility. Always assume a downed line is still energized and dangerous.
- Anyone who is without power and has a medical condition for which no electric service is a concern should consider finding alternate accommodations for tonight.



Map Updated: Oct. 18, 2007 2:30 p.m.



Map Updated: Oct. 19, 2007 11:30 a.m.

Latest Updates

Update
Tips for Customers

Service Alert Updates
As of Nov. 12, 2007, 3 p.m.

The windstorm that brought down trees and tree limbs across much of the Puget Sound region this morning knocked out electric service to approximately 77,000 Puget Sound Energy customers by the time the storm peaked in midafternoon. As of 3 p.m. today, PSE line crews had made significant progress restoring power, with electricity back on for more than 33,000 of the affected homes and businesses.

About 55 PSE line crews, with assistance from approximately 30 outside crews being brought in from Eastern Washington and Oregon, will continue the restoration effort until all the homes and business that lost power have had their service restored.

Whatcom and Thurston counties sustained the brunt of the storm's outage totals within PSE's Puget Sound nine-county electric-service area, but numerous scattered outages also occurred in Pierce, King, Kitsap, Jefferson, Island, and Skagit counties.

> PSE expects its crews to have power restored to virtually all customers – with the possible exception of some small, isolated pockets – by around 10 p.m. tonight in King, Skagit, Island, Jefferson, and Kitsap counties, and by around 7 a.m. tomorrow in Pierce County.

Crews this afternoon had not yet completed their assessment of all the extensive storm damage that occurred in Thurston and Whatcom counties, even as line crews there continue restoring power. No restoration-time estimate is yet available for these two counties, but damage repairs definitely will continue into Tuesday.

All "outside" line crews coming in to assist PSE's restoration effort are being dispatched to Thurston and Whatcom counties. In addition, a helicopter was being enlisted this afternoon to assess and pinpoint damage to a high-voltage transmission line serving communities along the Mount Baker Highway east of Bellingham.

Customers in Whatcom and Thurston counties who are without power and have special medical needs or conditions may want to consider finding alternate accommodations, if possible, for tonight.

The National Weather Service is predicting today's high winds (of up to 60 mph) should begin to ease in Western Washington by about 4 p.m.

SERVICE ALERT
Latest Updates
Outages - What to Do
Safety Tips
Service Alert Map

General Info: 1-888-225-5773

Latest Updates

Service Alert Updates
As of Nov. 13, 2007, 4:30 a.m.

Update
» Tips for Customers

Puget Sound Energy crews today are wrapping up the restoration of electric service to customers who lost power from the windstorm that hit Western Washington on Monday.

As of 4:30 a.m. today, about 8,000 PSE customers in Whatcom County -- where winds topped 90 miles per hour yesterday -- and about 3,000 in Thurston County remained without power from Monday's storm. All but scattered pockets of these customers should have their service restored by around noon today, with the rest seeing their lights come back on by late afternoon, at the latest.

In all, about 77,000 homes and businesses served by PSE in Whatcom, Skagit, Island, Jefferson, Kitsap, King, Pierce, and Thurston counties lost electric service from the trees and tree limbs yesterday's storm brought down into power lines.

Within PSE's broad, nine-county electric-service area, Whatcom and Thurston counties sustained the majority of the damage and power outages from Monday's storm. Most of customers elsewhere who lost power had their service restored by late Monday afternoon, with the rest regaining their service last night.

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The energy to do great things

November 13, 2007

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SERVICE ALERT
- Latest Updates
- Outages - What to Do
- Safety Tips
- **Service Alert Map**

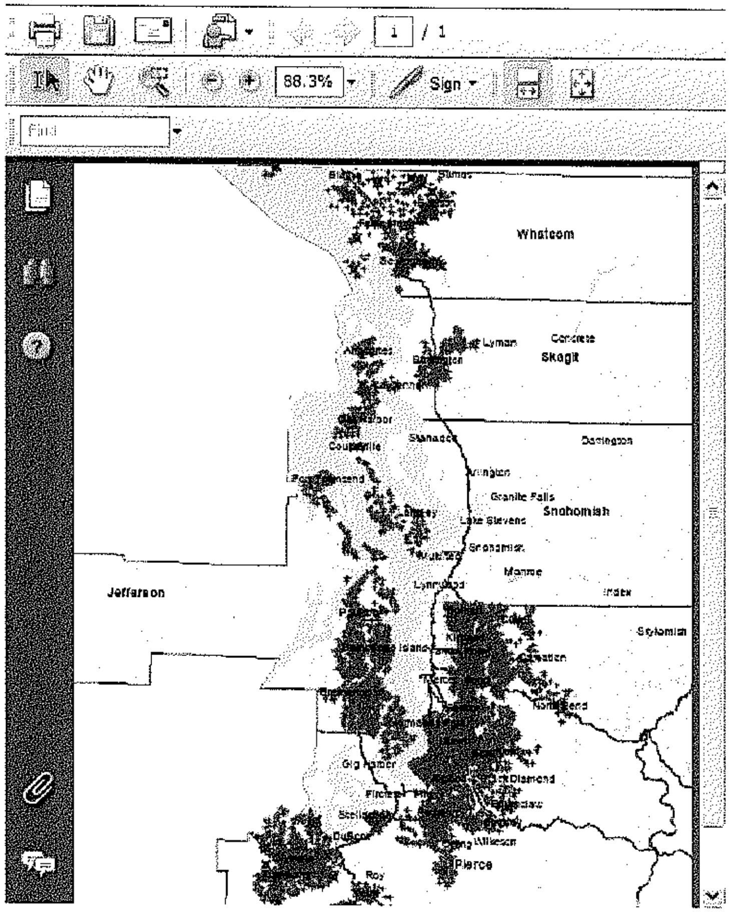
General Info: 1-888-225-5773

PSE Service Alert: Service Alert Map

PSE Service Area and County Restoration Map

This map displays the status of PSE's electrical distribution system as of 7 a.m. Mon., Nov. 13.

Legend: Map Symbols
- with service
- without service



Open PDF Map (357 KB).

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PUGET SOUND ENERGY

Corporate Communications
Windstorm Update – 4:30 a.m. Tuesday, Nov. 12, 2007

Puget Sound Energy crews today are wrapping up the restoration of electric service to customers who lost power from the windstorm that hit Western Washington on Monday.

As of 4:30 a.m. today, about 8,000 PSE customers in Whatcom County and about 3,000 in Thurston County remained without power from Monday's storm. All but scattered pockets of these customers should have their service restored by around noon today, with the rest seeing their lights come back on by late afternoon, at the latest.

In all, about 77,000 homes and businesses served by PSE in Whatcom, Skagit, Island, Jefferson, Kitsap, King, Pierce, and Thurston counties lost electric service from the trees and tree limbs yesterday's storm brought down into power lines.

Within PSE's broad, nine-county electric-service area, Whatcom and Thurston counties sustained the majority of the damage and power outages from Monday's storm. Most of customers elsewhere who lost power had their service restored by late Monday afternoon, with the rest regaining their service last night.

komo 4

November 12, 2007

Another potent windstorm strikes Western Washington

By Scott Sistek

What's New: High Wind warning issued for Puget Sound area; Wind Advisory issued for Southwestern Washington. Updated a few peak wind gusts.

A second strong windstorm of the season is rolling through Western Washington this morning, bringing a dose of heavy rain and very gusty winds to most of the region.

A truck that was struck by a falling tree during a wind gust Monday morning is seen on Novelty Hill Road in Redmond, Wash. The driver was hospitalized.

Thousands of customers were already without power by 7 a.m., and a driver in Redmond was hospitalized when a tree crashed down onto his truck near the intersection of Novelty Hill Road and 206th Avenue.

Seattle City Light reports about 4,000 customers without power in the Burien area, Snohomish PUD says about 1,400 customers have lost power, and Puget Sound Energy says they have scattered outages in Whatcom, Skagit, Kitsap and King counties.

The wind will be the largest impact with this storm, with gusts expected as high as 70 mph along the coast and 60 mph Northwest Interior, and perhaps as high as 50-60 mph in the Puget Sound area.

HIGH WIND WARNINGS are in effect for all of Western Washington, with the exception of Southwestern Washington, which is under a lesser WIND ADVISORY. (A high wind warning means wind gusts over 58 mph are possible. A wind advisory is for gusts over 40 mph). The warning is in effect from now until 1 p.m. for the coast and north interior, and from 10 a.m. to 4 p.m. for the greater Puget Sound area.

Here's some peak gusts already this morning as of 7 a.m., with the storm still offshore:

- Destruction Island: 75 mph
- Tatoosh Island: 73 mph
- Oak Harbor: 62 mph
- Hoquiam: 61 mph
- Bellingham: 55 mph
- Friday Harbor: 58 mph
- Alki Beach: 55 mph
- Hoquiam: 54 mph
- Forks: 52 mph
- Tacoma: 45 mph
- Seattle: 41 mph
- Everett: 39 mph

What's The Timeline? -- New as of Monday morning

As usual with windstorms, the coast gets the wind first, then the Northwest Interior (basically a box from Everett west to Port Townsend, stretching north to the Canadian border, including San Juan, Whidbey, and Camano Islands.), then finally the Puget Sound region.

The strongest winds are already under way along the coast and North Interior as the storm begins to pass by to our northwest. Peak wind gusts are expected to last there until midday or early afternoon. For the coast, we could see wind gusts as high as 70 mph.

For the Northwest Interior, strong winds are expected to continue through midday to perhaps another push in the late morning when the storm passes to the north.

Gusty winds were also already occurring in the Puget Sound area this morning, but this was not the main event as of 6 a.m. A stronger push of wind is expected somewhere in the vicinity of 10 a.m. when the storm passes to our north and the storm's cold front swings through.

The really strong winds won't last long as the storm is moving pretty quickly, but we could see a solid 2-3 hours of wind gusts approaching 60 mph later this morning.

Those winds would be strong enough to cause power outages, knock over trees and make driving across the 520 Bridge oh so fun. In October's storm, the 520 Bridge managed to stay open despite occasional gusts over 50 mph, while the Hood Canal Bridge did have to close for several hours. We could see a repeat of that on Monday -- and this time the 520 bridge could close.

Final note here for our Canadian readers -- while our High Wind Watch ends at the border due to jurisdictional procedures, (i.e., it's up to the Canadian forecasters to issue warnings for their side), this storm is expected to make for strong, gusty winds across southern Vancouver Island and the greater Vancouver area too. Vancouver's version of the National Weather Service (Environment Canada) is calling for wind gusts up to 55 mph (90 km/h) Monday morning.

The Meteorological Lowdown:

A strong area of low pressure is tracking toward north-central Vancouver Island on Monday. This is close to a classic wind storm pattern for us. (If we were to call it a "text book" case, we would want it going ashore either near Neah Bay or along the southern tip of Vancouver Island).

Nonetheless, while the storm is expected to go ashore farther to the north, it is fairly strong and that strength will make up for some of the energy lost to it being farther away.

Buoy reports also have the storm perhaps a bit stronger than the forecasting models think it is, so that's why the High Wind Warning was expanded overnight to include the Puget Sound area. Central pressure of the storm could be in the 968-972mb range by the time it makes landfall on Vancouver Island later this morning.

The storm also now looks to come ashore even farther north than it did on Sunday morning -- the north-central tip of Vancouver Island as opposed to Central Vancouver Island. But on the flipside, as we mentioned, the models have the storm stronger when it comes inland, and the buoys say it could even be a touch stronger than the models.

For us, the fact that the storm will be stronger but farther away will counter-balance each other, so our forecasted wind speeds are still the same. This does probably mean that central Vancouver Island and southern B.C. inland areas (like Vancouver and Whistler) will get stronger winds

How Does This Storm Compare?

(This will be updated later Monday morning when we get more data. Below is from Sunday night.)

It's nowhere near the December of 2006 storm, but it could be in the realm of the storm that hit a few weeks ago in mid-October. That was a 980mb storm, but it came ashore a lot closer to our area. Our big historical windstorms have had central pressures in the 955-970mb range, and have come in much closer to our area.

Note that in the October storm, the far northern areas were somewhat spared from the winds we were expecting, because the storm came in farther south. The Monday storm has a more classical path, so I would actually expect the forecasted wind speeds across that entire region this time. Also, we're not expecting much in the way of east wind through the Cascade foothills this time, as this storm doesn't seem to have a classic east-west set up for winds.

(As an aside, those of you who read my Friday forecast talking about a huge storm in the Pacific for Monday on par with a Category 3 hurricane -- that disappeared from the models the next day, so was an apparent model error. This storm is not related.)

Don't Forget The Rain

Aside from the wind, Monday will be very wet as well as the front brings a good dose of rainfall along for the ride. It's not quite cold enough for mountain pass snow Monday -- snow levels will be around 4,500 feet -- but snow levels do drop to 2,500-3,000 feet Monday night and Tuesday. We won't have much moisture by then, but could make for a little snow in the passes.

Where Do We Go From Here?

Winds will gradually decrease through Monday evening and night, as rain changes to showers, then decrease. We actually calm down quite a bit for Tuesday with showers in the morning then tapering off for the afternoon.

Long range forecasts show a return to generally wet and breezy conditions through the end of the week. The storms will pack a good dose of rain, but not as much wind -- jut the usual 20-30 mph stuff. The wettest periods appear to be Wednesday evening/night; Thursday evening/night; and during the day on next Saturday. In between, we'll see scattered showers. High temperatures through the period will be around 50.

komo 4

November 13, 2007

Power restored to most customers

SEATTLE -- One day after a storm with winds gusting to nearly 100 mph blew through Western Washington, crews had restored power to all but about 11,000 customers.

Puget Sound Energy said most of those still without power were in Whatcom and Thurston Counties, and line crews hoped to have electricity flowing to most of those homes by noon today.

A PSE spokesman said a main transmission line near the town of Glacier in east Whatcom County is down and crews have to build a road to get repair equipment into the area.

Linnette Engler sent in this photo of wind-blown power lines in Bellingham

At the storm's peak midday, about 100,000 people had lost power.

The Rainier School District and Ocean Beach School District cancelled classes Tuesday because of power outages, and in Whatcom County the Meridian School District had to close Reither Primary School and Ten Mile Creek Elementary School.

While the main Puget Sound area was mostly spared the worst, the coast and Northwestern Interior sections of the state had the strongest winds since the December 2006 windstorm.

Clallam Bay reported a gust to 92 mph, while Bellingham had an official gust to 74 mph, and an unofficial gust of 97 mph from a trained spotter six miles northeast of the city (that might have been a localized effect.) Anacortes recorded a gust to 73 mph, while on the coast, wind gusts were between 70 and 79 mph, including 71 mph at Hoquiam.

Here are some peak overall storm gusts.

- Bellingham (trained spotter, but unofficial): 97 mph
- Clallam Bay: 92 mph
- Lake Lawrence: 84 mph
- Tatoosh Island: 78 mph
- Destruction Island: 75 mph
- Bellingham (official): 74 mph (then 71 again at 10 a.m.)
- Anacortes: 73 mph
- Hoquiam: 71 mph (they've hit over 70 a few times)
- Oak Harbor: 70 mph
- Smith Island: 68 mph
- Westport: 67 mph
- East Strait of Juan De Fuca Buoy: 64 mph
- Friday Harbor: 63 mph
- Ferndale: 62 mph
- Port Angeles: 58 mph (early Monday a.m.)
- Point Robinson: 57 mph
- Forks: 57 mph (last observation before power outage at 6 a.m.)

- Seattle (Alki Beach): 55 mph
- Hoquiam: 54 mph
- La Conner: 53 mph
- Tacoma: 53 mph
- Forks: 52 mph
- Seattle (Magnolia): 51 mph
- Orcas Island: 48 mph
- Seattle (Sea-Tac): 47 mph
- Olympia: 46 mph
- Everett: 39 mph

The Meteorological Lowdown:

A strong area of low pressure of at least 967mb made landfall along the northern tip of Vancouver Island around 8 a.m. Monday. This was close to a classic wind storm pattern for us. (If we were to call it a "text book" case, we would want it going ashore either near Neah Bay or along the southern tip of Vancouver Island).

Nonetheless, while the storm went ashore farther to the north, it was fairly strong and that strength made up for some of the energy lost to it being farther away.

That 967mb report came from Solander Island, off the northwest coast of Vancouver Island and near the storm's center. (They also had wind gusts to 79 mph).

The storm's path allowed for strong south winds along the coast, and strong southeast winds along the northern interior. The Olympic Mountains protect the main Puget Sound area from those southeast winds, but usually that area gets the wind when the storm's center passes due north and the associated cold front opens the chute for the due south winds to race toward the low.

However, in this case, the front was aligned to where it allowed some of the building wind surge to push through via the Strait of Juan de Fuca. That alleviated some of the pressure difference so when the front passed through the Puget Sound region, we didn't have as much of a surge left.

We still had wind gusts into the 40-45 mph range (Spots near Puget Sound were over 50 mph) but not as much as we had feared. (The storm making landfall father to the north also helped let Puget Sound region off the hook.)

Southern British Columbia did get hit hard by the storm, as they were closer to the storm's landfall. Gusts around the greater Vancouver area were in the 55-60 mph range.

How Does This Storm Compare?

This storm's central pressure was on par with the December 2006 storm and actually stronger than the Inauguration Day storm of 1993. However, it made landfall much farther north, and that spared the Puget Sound area the bulk of the wind.

This storm was the strongest storm to hit the coast and Northern Interior since the December 2006 storm. In fact, Bellingham, Friday Harbor and Hoquiam had stronger winds with this storm than the December '06 storm.

KING 5

November 13, 2007

Cleanup begins after wind storm hits Northwest

SEATTLE — The cleanup continues this morning after Monday's windstorm knocked out power to thousands around Western Washington.

At the height of the Veterans Day windstorm, winds gusting from 70-95 mph blew trees and branches onto power lines and cut electricity to nearly 85,000 homes and businesses, from the Canadian border all the way south to Vancouver, Wash.

While the storm wasn't as bad as last December's windstorm, it caused a fair amount of damage. In the town of Rainier, high winds blew off part of the roof of a store. In Yelm, winds shattered a barn, and several large trees were uprooted.

Puget Sound Energy reports 11,000 customers are still without power Tuesday morning - 9,000 in Whatcom County and 2,000 in Thurston County. PSE says most of its customers should be back online by noon.

Clallam County has 12,000 without power, but they're expected to also be back up by midday. In other areas, power isn't expected to get back up until Tuesday night.

School closures and delays

Some schools were closed or delayed Tuesday due to damage from Monday's wind storm.

All schools in the Rainier School District in Thurston County are closed because of power problems. In the Ocean Beach District, all schools will now be closed.

The Yelm School District is running two hours late. There's no morning pre-school, no skill center and no out-of-district transportation.

High winds clocked at 97 mph

The National Weather Service said the strongest gust of wind it recorded was 97 mph along the Mount Baker Highway east of Bellingham about 9 a.m. Winds at Bellingham International Airport, about 80 miles north of Seattle, gusted to 74 mph.

A weather station at Bellingham Cold Storage, on Bellingham Bay, recorded a gust of 84 mph. Sustained winds were around 45 mph, and wind speeds alone broke several windows.

Other wind gusts reported by the National Weather Service about noon included 71 mph at Hoquiam, 62 at the Whidbey Island Naval Air Station near Oak Harbor, 56 at Friday Harbor, 55 at Quillayute on the Olympic Peninsula, 53 at McChord Air Force Base near Tacoma, 48 at La Center, 46 in Kelso, 45 at Burlington, and 41 at Olympia and Seattle-Tacoma International Airport.

Widespread power outages

One of the earliest power outages was before dawn around Monroe, where about 8,000 customers lost power for a time after three substations went off line, said Neil Neroutsos, a spokesman for the Snohomish County Public Utility District.

That problem was resolved fairly quickly, but later storm-related problems cut power to about 1,400 customers in the Lake Stevens area, Neroutsos said.

The region's largest utility, Puget Sound Energy, had roughly 37,000 customers in the dark at various times in nine counties, with Whatcom and Thurston counties hit the hardest, spokeswoman Christina Mills said.

More than 15,000 customers were without electricity in the Grays Harbor County Public Utility District, spokeswoman Liz Anderson reported.

At least 9,300 Cowlitz County PUD customers also lost power, along with 8,000 in the Clallam County PUD, utility officials said.

Seattle City Light reported nearly 3,900 customers lost power in the Burien area because of a failure in a feeder line.

Eastern Washington also had problems. Spokane-based Avista Utililties said about 1,140 customers lost power in Eastern Washington and northern Idaho from wind-related power outages.

Windy weather was blamed for outages that hit about 2,000 homes and businesses north of Vancouver, Wash., mostly in and around Yacolt, Amboy and Ridgefield, said Mick Shutt, a spokesman for the Clark County Public Utility District.

Snow in the Cascades

The Weather Service issued a snow advisory for the Cascade mountain passes, with the possibility of four to eight inches falling near Steven's Pass Monday night.

Snoqualmie Pass east of Seattle had wet snow and slush on a 20-mile stretch of Interstate 90 from the summit to Easton, transportation officials said.

Additional snow removal crews were summoned to keep the road clear for holiday traffic.

Oregon

High winds also cut power to tens of thousands of Oregonians Monday including about 15,000 on the north coast and up to 35,000 at a time inland, mostly in Marion, Washington, Clackamas and western Multnomah counties.

Portland General Electric said outages in its area were as high as 35,000 at midday as service was restored to some areas but then failed elsewhere as a powerful Pacific frontal system moved through the area.

About 300 crewmen were working on restoring service.

By late afternoon about 16,000 PGE customers remained without electricity.

The urban science of wind

The wind storm provided the first test of a network of 23 sensors placed atop light poles in Downtown Seattle that use the sound of the wind to measure wind speed and direction.

The wind bounces off buildings and goes all over the place. Now, these microenvironments can be measured.

"We had some winds at 22-23 miles an hour. Parts of Downtown never got above five (miles an hour), because the wind, once it gets into the urban canyons, breaks up and goes every which way," said Bob Royer, director of the Urban Canyons Program.

In this case, the system is providing interesting weather information. But, that data could also prove critical to predicting what direction a plume of hazardous material or even radiation from a terror attack might travel.

PENINSULA DAILY NEWS
Your Peninsula. Your Newspaper.

November 13, 2007

Jefferson weathers 60-mph winds

By Jeff Chew, Peninsula Daily News

Power was expected to be restored to all areas of East Jefferson County today after wind gusts of up to 60 mph hammered the area on Monday.

The early-morning storm knocked trees into power and fiber optic lines and disrupted service from Brinnon to Discovery Bay and Port Townsend.

Some of OlyPen's DSL customers remained off-line Monday evening.

Other Internet and cell phone services for OlyPen's 10,000 customers in Jefferson and Clallam counties were restored Monday afternoon, said Dana Dyksterhuis, a Qwest spokeswoman in Seattle.

The storm had sent a tree onto power lines and a fiber optic cable at Eaglemount Road on state Highway 20 near Discovery Bay, crippling Qwest's long-distance and digital service across the North Olympic Peninsula.

Qwest repair crews had to wait until utility workers could clear electric lines at the site Monday morning.

They were working to splice the fiber optic line Monday afternoon.

Puget Sound Energy spokeswoman Dorothy Bracken said that electricity was expected to be fully restored to 13 east county locations this morning.

1,300 lost power

"As of 2 p.m. [Monday] there were 1,300 customers without power in Jefferson County," Bracken said.

"Most [locations] have been scattered - where trees or tree branches hit power lines."

Although she did not know which communities were hit hardest, Bracken estimated that the largest number of customers affected in any individual area was about 100.

"What's labor intensive is going from location to location to make the repairs," she said.

A total of 77,000 Puget Sound-area customers were affected by the windstorm she said.

The good news is, according to weather forecaster Brad Coleman, "This event's done. We've taken all the warnings down."

"But it is probably pretty safe to say that the gusts were up to 60 mph in Eastern Jefferson County," said Coleman, with the National Weather Service in Seattle.

Dykstерhuis said trees felled some of the company's fiber optic lines, which also affected cell phone service.

Many people found they had dial tones, she said, but could not dial through, as a result of the tree-damaged lines.

She explained that the broken fiber lines diminished the Qwest system's capacity to handle increasing calls.

Lt. Clint Casebolt, State Patrol spokesman, said the law enforcement agency reported trees down so that Department of Transportation crews could clear highways and roads.

Reports of fallen trees came before 6 a.m., especially between Brinnon and Quilcene and on state Highway 19.

Gardiner and Discovery Bay were also hit, but fewer trees fell there, he said, adding, "It was all cleaned up by noon."

Port Townsend Police Detective Jason Greenspane said that several fallen trees were reported around the city, with power lines knocked down at 49th Street near Cook Avenue.

"Several partially blocking trees have been removed," he said Monday afternoon.

A roof was partially blown off an unoccupied former thrift store building on Upper Sims Way adjacent to First Federal Savings & Loan.

Greenspane also reported wind-whipped waves early Monday that crashed up against the bulkheads on the downtown waterfront, but resulted in no significant damage.

THE BELLINGHAM HERALD
November 13, 2007

Ferocious winds create howling havoc

By KIRA MILLAGE

Fall winds whipped through Whatcom County Monday morning, knocking down trees, taking out utility lines and giving many residents a case of déjà vu.

The first major windstorm of the season came a few days shy of the anniversary of the Nov. 15, 2006, windstorm that uprooted trees, caused two buildings to catch fire and knocked out power to large areas across the county.

Wind speeds peaked Monday between 8 and 9 a.m., with the National Weather Service reporting gusts of 97 mph on Mount Baker Highway and 74 mph at Bellingham International Airport. A weather station at Bellingham Cold Storage, on Bellingham Bay, recorded a southwest gust of 84 mph. Sustained winds were about 45 mph.

The winds and falling trees closed roads and took out dozens of power lines. Puget Sound Energy had 15,000 Whatcom County customers without power as of 4:30 p.m. It was unclear how many homes overall lost power at some point Monday. Outages were reported across the county.

"Of our eight counties in Western Washington, Whatcom and Thurston where hardest hit" in terms of number of customers losing power, PSE spokeswoman Dorothy Bracken said.

PSE crews were working through the night to restore power. Most customers should have power restored by daybreak today, she said. Some remote spots might not have power until about noon today.

Some roads might still be closed today as well. Whatcom County Public Works couldn't clear many areas Monday because they were waiting for PSE to clear downed power lines first.

During the peak of the storm, Samish Way-area resident Stanley Emert and his wife received a surprise while sitting in their kitchen eating breakfast. About the top third of a nearby 130-foot tree landed on the carport, porch and roof of their mobile home.

Emert, who moved there about six weeks ago, said they were also without power for several hours, but the house is still habitable.

"This is quite a welcome," the 85-year-old said with a laugh.

Many residents escaped Monday's storm without tree or power damage, but wind speeds alone broke several windows.

Bellingham resident Cathy Leahy had a skylight blow off her kitchen roof in the windstorm. She wasn't too worried or upset — until the wind started dying down and the rain picked up.

"It's raining in my house," she said while trying to mop up the water. "I should probably call the window guys now."

Boats in local marinas received minor damage in the wind, but a small motorboat partially sank about 3 p.m. in Lake Whatcom off a dock near the corner of Lake Whatcom Boulevard and Morgan Street. Firefighters with Whatcom County Fire District No. 2 surrounded the boat with an absorbent boom to isolate gasoline seeping from the boat.

THE NEWS TRIBUNE
November 13, 2007

South Sound spared heavy damage Winds down trees, power lines

By STACEY MULICK

You shouldn't have as hard a time today keeping your hat on or your umbrella under control.

The forecast calls for partly sunny skies with a chance of showers and winds between 10 and 15 mph.

That'll be a relief after Monday's blustery weather knocked down power lines and trees, leaving thousands in the dark.

Nearly 85,000 lost power throughout Western Washington on Monday thanks to winds that gusted to more than 70 mph in some spots. Whatcom, Snohomish and Thurston counties appeared to be among the hardest hit.

At its peak, Puget Sound Energy had roughly 77,000 customers without electricity in nine counties, including Pierce, King and Thurston. The outages in Pierce County occurred in Lakewood, Fife and southern unincorporated areas of the county.

As of 7 p.m. Monday, the utility still had 573 customers in Pierce County without electricity. Power was expected to be restored to them by 7 a.m. today, Puget Sound Energy spokeswoman Dorothy Bracken said.

Seattle City Light reported nearly 3,900 customers without power in the Burien area because of a failure in a feeder line, and more than 100 without power in Seattle for other reasons.

Most of Tacoma Power's customers survived the windstorm unscathed. The utility reported only small outages in pockets throughout its area. At one point in the afternoon, 30 to 40 customers were without power, spokeswoman Sonja Hall said.

"We fared really well so far, so we are pleased with that," she said.

At the height of the storm around noon, the National Weather Service recorded wind gusts of 71 mph at Hoquiam, Grays Harbor County; 68 mph in Bellingham; 62 mph at the Whidbey Island Naval Air Station near Oak Harbor; 56 mph at Friday Harbor, San Juan County; 55 mph at Quillayute on the Olympic Peninsula; 53 mph at McChord Air Force Base; 48 mph at La Center, Clark County; and 41 mph at Olympia and at Sea-Tac Airport.

Snoqualmie Pass had wet snow on a 20-mile stretch of Interstate 90 from the summit to Easton, transportation officials said.

AP Associated Press

November 13, 2007

High winds cut power to more than 13,000 in Washington state

SEATTLE -- Utility crews remained busy Tuesday following windstorms that brought hurricane-force winds to parts of Washington state and cut electricity to more than 130,000 homes and businesses.

The worst of the damage, including cars and houses hit by falling trees and windows shattered by wind, and the bulk of the power outages Monday were west of the Cascade Range, especially along the coast and in the northwest part of the state.

The strongest gusts of wind reported by the National Weather Service and other weather observers were 119 mph at Camp Muir at the 10,100-foot level of Mount Rainier; 98 on Rattlesnake Mountain, west of the Tri-Cities; 97 along State Route 542, the Mount Baker Highway, east of Bellingham; 92 at Sekiu and Clallam Bay on the northern Olympic Peninsula west of Port Angeles, and 84 mph at a business on Bellingham Bay.

Most of the electrical outages were repaired by midnight.

The region's largest utility, Puget Sound Energy, had roughly 77,000 homes and businesses in the dark at various times in its nine-county service area.

By early Tuesday, spokeswoman Dorothy Bracken said, the number was down to 11,000 customers, including 9,000 in Whatcom County, which includes Bellingham, and 2,000 in Thurston County, which includes the state capital of Olympia. She said the vast majority would likely have their lights back on by noon.

About 17,000 customers lost power in the Clallam County Public Utility District, which covers the northern part of the Olympic Peninsula. In the neighboring Grays Harbor County PUD, on the coast, more than 15,000 were in the dark.

Internet and cellular telephone service to about 10,000 customers in Clallam and Jefferson counties was lost for hours after a tree was blown onto power lines and a fiber optic cable on State Route 20 near Discovery Bay, south of Port Townsend, Qwest telecommunications officials said.

Other electrical outages affected about 10,000 customers each in the Snohomish and Cowlitz county PUDs, 4,000 in the Seattle City Light service area and 2,000 in the Clark County PUD.

East of the mountains, Avista Utilities had about 1,140 customers without power in Eastern Washington and northern Idaho and Pacific Power had more than 2,100

The storm also caused a 10-acre brush fire that took 30 firefighters from five agencies about two hours to control in Wapato. Fire officials said the fire started when high winds snapped a tree limb that knocked a power line to the ground.

Blowing dust that cut visibility to near zero was likely a factor in the rollover of a tractor-trailer rig carrying fertilizer on U.S. Highway 97 south of Toppenish, the State Patrol reported, and also resulted in workers at the Hanford nuclear reservation being sent home early Monday afternoon.

The Bellingham Herald

November 12, 2007

Overnight storm blamed for power outages

By ANDY CAMPBELL

An overnight storm has caused outages in Blaine, Lynden and scattered areas in Bellingham this morning, and high winds are expected to continue today.

A Puget Sound Energy spokeswoman said an entire circuit in Lynden was cut, leaving more than 700 without power. She said it is the most widespread outage in Whatcom County this morning, and those people should get power back within the next few hours.

PSE also reported scattered outages around Whatcom, Skagit and King Counties, and KING-TV said three substations near Monroe are off line, cutting off power for about 8,000 utility customers.

The National Weather Service is warning of high winds today on the Washington coast and other parts of Western Washington, including the Puget Sound area. A spokesman said peak winds are hitting 60 to 65 mph, with a sustained wind of 45 mph that will last throughout the morning.

Winds should die down midday, he said.

Forecasters say a front blowing through the rest of the state is packing winds of 30 to 40 mph with gusts to 60. That's enough to knock trees into power lines.

Seattle Post-Intelligencer

More than 20,000 power outages in Western Washington

SEATTLE -- High winds blowing through Western Washington knocked out power this morning for more than 20,000 utility customers.

Three substations went off line near Monroe, putting about 8,000 customers in the dark for a time. A spokesman, Neil Neroutsos (ner-OOT'-soh), says that problem has been resolved. But storm-related outages have cut power to about 1,400 customers in the Lake Stevens area.

Puget Sound Energy reports 9,000 to 10,000 outages in Whatcom, Skagit, Island, Kitsap and King counties.

Seattle City Light reports nearly 3,900 customers without power in the Burien area because of a failure in a feeder line.

KING 5

October 19, 2007

Windstorm tests improvements to PSE

By GLENN FARLEY

DUVALL - The first major winter windstorm that swept through Puget Sound Thursday had power crews scrambling to restore power.

It was the first test of big improvements made to Puget Sound Energy's vegetation management system after last December's big windstorm, which left some customers without power for up to 10 days.

This year, the utility increased its budget for clearing trees away from power lines by an additional $2 million - $12 million total, for what is called "vegetation management."

"It is all tree related outages that occurred yesterday. So anything that keeps a tree limb or a tree clear of the power line is well worth the effort," Bracken said.

By early this Friday evening, Puget Sound Energy still had 9,000 people without power, mostly in north and south King County and Kitsap County. Snohomish County PUD had 7,500 customers out and Tacoma Power was almost fully restored with 250 customers out. Seattle City Light had no outages.

Crews have been out day and night getting the power back on. A map of PSE's power outages shows 160,000 customers out at the peak late Thursday afternoon. But in December of 2006, power was out everywhere it seemed. It was a much stronger storm, but also occurred later in the year when there were fewer leaves on trees like Cottonwoods.

A map from back then shows 700,000 customers in the dark, for as long as nine and 10 days.

"It was the most devastating storm we've ever experienced in our history," said Dorothy Bracken, a spokesperson for PSE.

The utility is at work replacing more power poles, and has designated zones, like Woodinville and Whidbey island, planning to put in back up power lines to keep the juice flowing

"We've also identified some hot spots, where we feel the some of the parts of the utility system need to be strengthened," Bracken said.

THE NEWS TRIBUNE

October 19, 2007

Wind takes trees, power

By IAN DEMSKY

If you're reading this, you survived the first storm of the fall. Luckily, the casualties Thursday were mainly trees, power lines, after-school activities and commutes. The only report of serious injury came from Kent, where a 60- to 75-foot cottonwood tree snapped in high winds and fell on a woman at shopping center just after 2 p.m.

KIRO 7 Eyewitness News reported a power line fell on a school bus in Maple Valley, causing it to be evacuated. And the Hood Canal Bridge linking the Kitsap and Olympia peninsulas closed for nearly three hours due to strong winds.

Weather watchers assure us the worst is over and today will be a bit yucky, but not nearly as severe.

"You'll see some showers and maybe a few thunderstorms as some cold air moves in," said Tim Roche, of Weather Underground forecasting service. "Other than that, it shouldn't be too bad."

What we saw Thursday were the remains of a tropical cyclone, he said, "but this thing that's coming in tomorrow is more your typical winter Pacific storm."

Tens of thousands in Pierce County lost power, but crews brought those numbers down quickly and continued to work late into the night. Figures weren't available from Puget Sound Energy, but Tacoma Power reported that at the worst point, 23,000 customers were without power.

As of 6 p.m. Thursday, the National Weather Service reported the day's highest sustained wind at Sea-Tac Airport was 39 mph, and the highest gust was 53 mph.

The highest gust reported by early evening was 62 mph in Spanaway, said Weather Service meteorologist Carl Cerniglia.

A plea to residents to be prepared with emergency supplies of food, water, batteries and other necessities was issued Wednesday by Gov. Chris Gregoire, who said state emergency management was on alert.

Before the storm hit, Puget Sound Energy crews were trimming trees away from power lines. Officials noted that many trees still had a full load of wind-catching leaves, making them vulnerable to being blown down or losing branches. The utility, which struggled to restore power to 700,000 homes and businesses in December, is spending an extra $2 million on tree trimming, spokeswoman Martha Monfried said.

WHIDBEY
NEWS-TIMES
October 20, 2007

Wind whips Whidbey Island

By Nathan Whalen

As the result of Thursday's first storm of the season, more than 15,000 homes on Whidbey Island lost power due to the high speed winds that buffeted the area that afternoon.

However, as of noon Friday, power had been restored to all but three homes on the island, according to Puget Sound Energy.

Winds reached speeds close to 50 miles per hour, according to information from the Naval Pacific Meteorology and Oceanography Detachment Whidbey.

The fall windstorm apparently spared the area from any significant damage.

Marv Koorn, chief of North Whidbey Fire and Rescue, said firefighters responded to only one call — a downed tree on Silver Lake Road.

"We had it pretty easy," Koorn said.

The high winds did prompt the cancellation of Thursday's swim meet between Oak Harbor and Everett. The Everett swimmers didn't make the trip to Whidbey Island.

On Central Whidbey, firefighters responded to nine calls during the windstorm. Central Whidbey Fire and Rescue Chief Joe Biller said that all those calls were to remove fallen trees that had blocked roads or driveways or had fallen into power lines.

He said that one lady in the Lagoon Point area nearly had to be relocated due to the power outage because she is on oxygen. Fortunately power was restored before she needed to be moved.

High winds wreaked havoc on Whidbey Island last year. Those winds caused numerous power outages, some lasting for days, and snarled traffic during the winter months.

8.4.1-C

From: Lofstrom, Daniel J
Sent: Sunday, November 11, 2007 7:03 PM
To: Storm Declaration - list -; System Managers Report - list -
Subject: High Wind Watch
National Weather Service has issued a High Wind Watch for Monday morning......

URGENT - WEATHER MESSAGE....CORRECTED
NATIONAL WEATHER SERVICE SEATTLE WA
358 PM PST SUN NOV 11 2007

.A 992 MB LOW APPROXIMATELY 700 NM WEST OF NORTH BEND OREGON WILL MOVE NORTHEAST TONIGHT AND DEEPEN. BY LATE MONDAY MORNING THE LOW WILL
MOVE INTO THE MIDDLE OF VANCOUVER ISLAND WITH A CENTRAL PRESSURE NEAR 982 MB. THE LOW WILL CONTINUE TO MOVE NORTHEAST MONDAY AFTERNOON. THE FRONT ASSOCIATED WITH THE LOW WILL REACH THE WASHINGTON COAST MONDAY MORNING AND MOVE THROUGH THE INTERIOR OF WESTERN WASHINGTON LATE IN THE MORNING. STRONG WINDS ARE EXPECTED AHEAD AND WITH THE FRONT ALONG THE COAST AND OVER THE NORTHWEST INTERIOR WITH STRONG WINDS POSSIBLE OVER THE REMAINDER OF THE LOWLAND WITH AND JUST AFTER THE FRONT.

WAZ504-505-507>509-511-512-120815-
/O.NEW.KSEW.HW.A.0006.071112T1200Z-071113T0000Z/
SOUTHWEST INTERIOR-EAST PUGET SOUND LOWLANDS-EVERETT AND VICINITY-
SEATTLE/BREMERTON AREA-TACOMA AREA-HOOD CANAL AREA-
LOWER CHEHALIS VALLEY AREA-
358 PM PST SUN NOV 11 2007

...HIGH WIND WATCH IN EFFECT FROM LATE TONIGHT THROUGH MONDAY AFTERNOON...

THE NATIONAL WEATHER SERVICE IN SEATTLE HAS ISSUED A HIGH WIND WATCH...WHICH IS IN EFFECT FROM LATE TONIGHT THROUGH MONDAY AFTERNOON.

A DEVELOPING STORM SYSTEM OVER THE EASTERN PACIFIC WILL STRENGTHEN TONIGHT AND MONDAY MORNING AS IT MOVES NORTHEAST.

THE FRONT ASSOCIATED WITH THIS LOW IS EXPECTED TO MOVE THROUGH THE AREA LATE MONDAY MORNING WITH STRONG SURFACE PRESSURE RISES BEHIND THE FRONT. SOUTH WINDS OF 30 TO 40 MPH WITH GUSTS TO 60 MPH ARE POSSIBLE WITH AND JUST BEHIND THE FRONT. THE HIGH WINDS ARE NOT EXPECTED TO LAST VERY LONG. AT THIS TIME IT LOOKS LIKE THE STRONGEST WINDS WILL BE IN A THREE HOUR WINDOW BETWEEN 10 AM AND 4 PM MONDAY. WINDS WILL DIMINISH SIGNIFICANTLY AFTER 4 PM.

HIGH WINDS CAN TOPPLE TREES...DOWN POWER LINES...AND DAMAGE SOME STRUCTURES. POWER OUTAGES WILL BE POSSIBLE WITH WINDS THIS STRONG.

HIGH WIND WATCH MEANS THERE IS THE POTENTIAL FOR A HAZARDOUS HIGH WIND EVENT. CONTINUE TO MONITOR THE LATEST FORECASTS FROM THE NATIONAL WEATHER SERVICE.

$$

FELTON
WEATHER.GOV/SEATTLE

PSE PUGET SOUND ENERGY

Emergency Operations Center UPDATE – for External Distribution

This report is provided for the following audiences:
State, County and City Emergency Management Division Staff
Regional Jurisdiction EOC's
Community Trade and Economic Development
Red Cross
Department of Transportation
Other Agencies

EOC e-mail: PSEEOC@pse.com
EOC FAX: 81-4450 or (425) 453-4450
(Revised 10/2007)

Event Name:	Lingering Ling *(remnants of Tropical Storm Ling Ling)*
Time and Date of this Update:	18:00 10/18/2007
Date and Time of Storm Event:	08:00 10/18/2007
Time Puget Sound Energy (PSE) EOC Opened:	14:15 10/18/2007
Time PSE EOC Closed:	

EOC Manager:	Don Yuen
EOC Director:	Jan Senk

Event Overview:

(Describe major problem areas, status of workforce working and en-route, etc.)

Puget Sound Energy is experiencing scattered power outages affecting thousands of customers in parts of Thurston, Pierce, King, Kitsap, and Island counties as a result of the strong winds hitting Western Washington.

PSE crews have been in the field restoring power to several thousand customers since this morning, but with strong winds still blowing, new outages continue to occur and no estimate is available at this time on the total number of PSE customers who've lost power.

Depending on how long the winds continue and the extent of damage it causes, it is not possible yet to provide an estimate of service restoration. We anticipate some restoration information tomorrow morning after assessment is complete.

PSE has approximately 60 line crews, together with about 19 tree crews and a full complement of damage-assessment crews, working to restore customers' power. In addition, another 7 line crews are in transit with others available as needed.

Incident Action Plan:

(System restoration plan at this time; e.g., priority restoration areas.)

We are calling crews in from Eastern Washington and Oregon to assist our restoration efforts. Crews will work through the night along with damage assessors to continue to restore service. Estimated restoration times by areas will be provided when assessment is complete. We anticipate having regional restoration information by mid day tomorrow.

System Status:

Region	Transmission Circuits Out	Substations Out	Distribution Circuits Out	No. Line & Tree Crews	# Cust. Out	Estimated Restoration Date/Time (if known)
Whatcom	0	0	0	9	64	
Skagit	0	0	1	9	2,957	
Island	3	3	10	1	5,171	
N. King	4	2	1	11	6,038	
S. King	2	1	10	14	9,656	
Pierce	4	0	3	8	10,166	
Thurston/ Lewis	1	1	3	11	11,158	
Pt. Townsend	0	0	0	0	206	
Poulsbo/ Kitsap	1	3	8	13	26,561	
Vashon	0	0	0	3	3,018	
Kittitas	0	0	0	0	0	
Totals	15	10	36	79	74,995	

PSE PUGET SOUND ENERGY

Emergency Operations Center UPDATE – for External Distribution

This report is provided for the following audiences:

State, County and City Emergency Management Division Staff
Regional Jurisdiction EOC's
Community Trade and Economic Development
Red Cross
Department of Transportation
Other Agencies

EOC e-mail: PSEEOC@pse.com
EOC FAX: 81-4450 or (425) 453-4450
(Revised 10/2007)

Event Name:	Veteran's Day Storm
Time and Date of this Update:	11/12/07 20:00
Date and Time of Storm Event:	11/12/07 4:30 AM
Time Puget Sound Energy (PSE) EOC Opened:	11/12/07 8:00 AM
Time PSE EOC Closed:	

EOC Manager:	Shamish Patel
EOC Director:	Booga Gilbertson and Harry Shapiro

Event Overview:

Corporate Communications
Windstorm Update – 8:00 p.m. Monday, Nov. 12, 2007

The windstorm that brought down trees and tree limbs across much of the Puget Sound region this morning knocked out electric service to approximately 77,000 Puget Sound Energy customers by the time the storm peaked in midafternoon. As of 8:00 p.m. today, PSE line crews had made significant progress restoring power, with electricity back on for more than two-thirds – about 55,000 – of the affected homes and businesses.

PSE crews have power restored to virtually all customers – with the possible exception of some small, isolated pockets – in King and Pierce Counties. Over the next several hours, we expect to complete most restoration activities in Skagit, Island, Kitsap, and Jefferson Counties.

In Whatcom County, most customers should have their power by daybreak tomorrow, though final restoration work may last until about noon. In Thurston County, the majority of affected PSE customers also should have their electric service back by daybreak, with final restoration work expected to continue until late Tuesday afternoon.

As PSE crews outside of Whatcom and Thurston counties complete their restoration efforts, they are being dispatched to Thurston and Whatcom counties to speed the restoration of customers' power.

Customers in Whatcom and Thurston counties who are without power and have special medical needs or conditions may want to consider finding alternate accommodations, if possible, for tonight.

Incident Action Plan:

Please see below table for an overview of the number of crews working in the field, and for estimated restoration times. All Storm Bases still open expect to complete restoration activities either with personnel already at the storm base, or with additional crews that are either traveling into the area, or being released as other storm bases close.

System Status:

Region	Transmission Circuits Out	Substations Out	Distribution Circuits Out	No. Line & Tree Crews	# Cust. Out	Estimated Restoration Date/Time (if known)
Whatcom	3	2	3	17	12,092	80% by 08:00 11/13
Skagit			1	7	509	11/12 24:00
Island				5	19	11/12 24:00
N. King	1			10	74	Closed
S. King				0	83	Closed
Pierce				9	243	Closed
Thurston/ Lewis	2		7	17	11,686	70% by 08:00 11/13
Pt. Townsend				11	594	11/13 02:00
Poulsbo/ Kitsap				2	28	11/13 02:00
Vashon				1	3	
Kittitas				0		
Totals	6	2	11	79	25,331	

9.4.1

Levels	Description	Electric Criteria	Gas Criteria	Level of Response	Customer Service, Corporate Communications, Community and Government Relations Actions
Green	Level 0 – Normal	Nominal conditions across system	Nominal conditions across system	Normal daily response activity.	Areas work with System Operations leadership to manage customer issues or needs.
Yellow	Level 1 - Regional	Event localized to individual geographic areas; resources within region adequate for response.	Localized event managed with regional resources.	Operations base(s) open; coordination with system operations or gas control. Gas Planning Strategy Center open for gas emergencies.	Operating bases will assign a "communications lead" as required to be a central point of contact for customer or community information. These individuals have past storm room experience, and the ability to find the information without disturbing storm base operations management who are focused on restoration. Logistics to support the process include the establishment of the Bothell Emergency Center (PSE's Call Center) with a formal escalation process and specifically trained personnel on point to manage customer calls, and the identifcation of qualified staff for PSe corporate headquarters. PSE's Industrial, major business customer and school/hospitals account representatives will work out of the EOC and gather information from System Operations.
Orange	Level 2 – Significant	Multiple regions affected; requires resources from other PSE regions and/or outside PSE service territory.	Multiple regions affected; requires resources to be allocated to other PSE regions.	EOC open; multiple operating bases and may activate local area coordination. Employees with emergency response assignments mobilized.	Operating bases will assign a "communications lead" as required to be a central point of contact for customer or community information. These individuals have past storm room experience, and the ability to find the information without disturbing storm base operations management who are focused on restoration. Logistics to support the process include the establishment of the Bothell Emergency Center (PSE's Call Center) with a formal escalation process and specifically trained personnel on point to manage customer calls, and the identifcation of qualified staff for PSe corporate headquarters. PSE's Industrial, major business customer and school/hospitals account representatives will work out of the EOC and gather information from System Operations.
	Level 3 - Major	Most or all regions affected; maximum level response required; need extensive resources from outside area.	Most or all regions affected; may request operator qualified resources from outside PSE.	EOC open; most or all operating bases open; external logistics support may be employed; full corporate response to support restoration efforts.	Operating bases will assign a "communications lead" as required to be a central point of contact for customer or community information. Depending on the volume of escalation in a major event, Base Operations may provide a point person in the Call Center to assist with information gathering. Officers of PSE have been provided emergency response roles for "major" events, including a group identified to support escalated calls at the Call Center. PSE's Industrial, major business customer and school/hospitals account representatives will work out of the EOC and gather information from System Operations.

11.4.1

PUGET SOUND ENERGY

Operations
Conference Call Agenda *(Rev. 10-5-07)*

SCHEDULE INITIATED BY EOC

(Calls tentatively scheduled at 06:30 and 14:30 (or close to shift changes at bases)

Subject	Responsibility	Est. Time
Weather Update	EOC	1 min.
Storm Base Reports ▪ # outages ▪ Subs out ▪ Transmission out ▪ Estimated overall damage *(% of area hit; % assessed)* ▪ # crews working and on-site ▪ # crews en route/time expected ▪ Resources needed??? *(damage assessment, CLX, tree/line crews, flaggers, materials, etc.)* ▪ Restoration plan ▪ Staffing plan; *shift change (who and when)*	Potelco Base Manager & EFR Supervisor	5 min/base
Storm Characterization – *for customer communications*	All	3 min.
Priority Issues	All	3 min.

12.4.1

Lodging Coordinator

Provide lodging coordination for regional operating bases, working with the Emergency Operations Center (EOC) to ensure adequate bed capacity for foreign crews and operating/storm base personnel. Manage local lodging arrangements (assign/track personnel and their lodging assignments) throughout emergency event. Coordinate with the EOC to request added lodging locations when additional beds are not available at locations already arranged by the EOC. Coordinate with hotel staff to arrange net additions/reductions in beds as needed throughout event, including providing hotel staff lists of personnel assigned to each facility, number of nights for each room, etc. Work with hotel staff as necessary to resolve lodging issues. Track and provide regular updates to the EOC on lodging utilization throughout the event.

PSE Liaison – County/City EOC(s)

Represent Puget Sound Energy (PSE) at assigned County or City Emergency Operations Centers (EOCs). Serve as liaison and focal point for communications between County EOC staff and PSE. Provide routine updates to County EOC staff on impacts to PSE's energy distribution system(s) and current restoration timelines. Identify key coordination issues between PSE and County (public works, police/fire, roads, parks, transit) DOT or Telco's and facilitate discussions to resolve. Collaborate with the Puget Suond Energy EOC and County Public Information Officers on community messaging. Coordinate with County staff to obtain additional resources if required. Participate in scheduled PSE conference calls. (City EOC's will be staffed on request of the jurisdiction for specific events affecting local areas. These requests are made to the Emergency Planning Manager or Manager Operations Continuity and will be staffed on an as needed basis.) Work schedules may vary, but are anticipated to be a minimum of 12-hour shifts during daytime hours, to be coordinated with the County EOCs.

PSE Liaison – State of WA EOC

Represent Puget Sound Energy at the State of Washington Emergency Operations Center (EOC), located at Camp Murray. Serve as liaison and focal point for communications between State of WA Emergency Management Division (EMD) staff and PSE. Provide routine updates to State of WA EMD staff on impacts to PSE's energy distribution system(s) and current restoration timeline. Identify key coordination issues between PSE and State of WA and facilitate discussions to resolve. Coordinate with appropriate State agencies to obtain temporary rules exemptions where restrictive regulation may adversely affect response efforts. Coordinate with EMD staff to obtain additional resources, as required. Work schedules may vary, but are anticipated to be a minimum of 12-hour shifts during daytime hours, to be coordinated with the State EOC.

12.4.2

PUGET SOUND ENERGY

PURCHASING EMERGENCY RESPONSE MANUAL

In the event of a Seasonal Storm or Major Disaster, such as fire, earthquake, or major storm, organized interaction between Purchasing and Material Distribution and Planning personnel will be crucial.

Organized interaction will assure that required material is issued to recovery crews in an expeditious manner.

Confidential

Updated: October 26, 2007

PO Box 90868 (PSE-10N)
Bellevue, WA 98009-0868
Phone: 425-462-3015
Fax: 425-462-3214
www.pse.com

Dale Brokaw
(Office)

EMERGENCY PURCHASES MATRIX

Material requested by MDP to route to Purchasing

Emergency or Storm Name:

In the yellow columns A - E: MDP enters their requests for materials needed for an Emergency or Storm Recovery. MDP enters a priority ranking number (1-5).

MDP sends this spreadsheet to the Manager of Purchasing or designee.

Since the material needed is for an emergency this spreadsheet is in lieu of a multi-line SAP purchase requisiton to expedite the sourcing process.

MID	Quantity Requested by MDP	Special instructions to purchasing from MDP	Date MDP created request	MDP Priority # 1 - 5	Assign to Buyer No.

Legend Below

MDP priority ranking number (1-5).

1) Needed ASAP - Next flight out (e.g. special air forwarding). Or via ground, same day truck, via local supplier's truck, local cartage company, or dedicated truck.

2) Required next day - AM Delivery (delivery by 8:00 AM preferred) via Air or truck (LTL or FTL ground shipment).

3) Required within 3 days - two or three day air service. Or via ground (LTL, FTL, or package delivery) from a West Coast supplier.

   If an expedited FTL (out-of-state) truck shipment is required, such as for overhead XFR's, request a two driver truck.

4) Required within 3 to 5 days - Regular ground freight, package delivery, LTL, or FTL (out of state).

5) Replenishment item - regular lead-times are adequate using regular shipping method (typically selected by supplier).

MDP can insert a buyer number if they request a specific buyer they want to source a designated Line Item (Optional)

13.4.1

Rec #	Major Recommendation	Recommendation Source
A	**Emergency Response Planning and Structure**	
1	Enhance PSE employees emergency response planning and execution capability (add 1-2 FTE's to Operations Continuity to support storm plan improvement recommendations)	Storm Team
2	**Enhance emergency response training**	KEMA 4 1
	a) damage assessor training	
	b) contract crew coordinator training	
	c) 911 call taker training	
	d) CLX training	
	e) Lodging coordinator training - new 2007/08	
	f) County/State EOC liaison training - new 2007/08	
3	Clarify ownership of emergency response responsibilities	KEMA 4 1
4	Expand PSE participation in County EOCs	KEMA 4 1
5	Develop succession plan for key positions	KEMA 4 1
6	Stock additional radios for foreign crews at storm bases	Internal Debrief
7	Increased radio frequency channels	Other Int Debrief
8	Increase radio capacity	Visioning
9	Provide additional cell phones that will work when power supplies are out	Visioning
10	Stock adequate quantities of storm bags in operating bases	Internal Debrief
11	Develop checklist for staging areas	Internal Debrief
12	Develop checklist for foreign crew contracting: materials, equipment, etc)	Internal Debrief
13	Develop plan for opening Whidbey Operating Base as appropriate: (staffing & triggers)	Internal Debrief
14	Formalize role of lodging coordinators in plan	Internal Debrief
15	Develop a storm categorization methodology and tailor aspects of the CERP to the various levels of storms.	KEMA 5.1
16	Build a storm database that tracks damage and restoration	KEMA 5.1
17	Document historical damage by area	KEMA 5.1
18	Develop initial process for early storm restoration estimates	KEMA 5 1
19	Develop process for early storm restoration estimates	KEMA 5 1
20	Increase the number of trained system operators to improve switching times	Visioning
21	Reinforce management support for employee participation in storm restoration	Visioning
22	Identify and train additional qualified and skilled employees for key emergency response roles including damage assessors, crew coordinators, dispatchers, system operators data entry, customer service representatives, and community representatives	Visioning
23	Provide more circuit map books to Operations Bases	Other Int Debrief
24	Provide more PSE all-wheel drive SUV's	Other Int Debrief
25	Assemble a list of electrical contractors who can do weather head or homeowner emergency type of work to not leave customers hanging on weekends or holidays in future	Other Int Debrief
26	Provide Company issued gear (hats/coats, etc) for all employees working storm	Other Int. Debrief

Rec #	Major Recommendation	Recommendation Source
27	Develop plan for fueling equipment when emergencies make it difficult to get gas	Other Int Debrief
28	For accountability, hire local people to work in their communities (don't make someone drive to Bremerton to do damage assessment who lives in Puyallup	Customer Focus Groups
B	**Emergency Restoration Execution**	
1	Enhance Damage Assessor training	KEMA 6 1
2	Revise DA process for estimating restoration and crew requirements	KEMA 6 1
3	Formalize field DA process to produce more consistent and actionable information	KEMA 6 1
4	Enhance PSE DA support capability	Team
5	Benchmark DA process best practices	Team
6	Streamline safety orientations for foreign crews	Internal Debrief
7	Expand use of GPS for crews damage assessors, crew coordinators	Internal Debrief
8	Enhance 911 call taker training and process to triage 911 calls	Internal Debrief
9	Develop plan to deploy additional helicopters for patrolling, damage assessment	Internal Debrief
10	Develop strategy to increase # of qualified flaggers available	Internal Debrief
11	Pursue WA State flagging certification exemption	Internal Debrief
12	Formalize utility road clearing task force" with DOT County/City Roads PSE Potelco and Asplundh	Governor's AAR
13	Request HOV lane exemption from State Patrol	Governor's AAR
14	Work with State EMD to obtain Governor's Declaration of Disaster	Governor's AAR
15	Review operating base management process	KEMA 7 1
16	Establish emergency restoration perfomance metrics	KEMA 7 1
17	Clarify emergency response roles of PSE and SP	KEMA 7 1
18	**Formalize local area coordination and transmission restoration priority activities.**	KEMA 7 2
19	Formalize and document local area coordination	KEMA 7 2
20	Develop Local Area Coordination Plan	KEMA 7 2
21	Establish triggers to launch Local Area Coordination	KEMA 7 2
22	Develop Local Area Coordination clearance procedures	KEMA 7 2
23	Develop process for triggering "transmission restoration priority teams" including communications to field and operations bases	Internal Debrief
24	Investigate increasing use of self-protected clearance to relieve system operations congestion	Visioning
25	Investigate using a qualified local area crew coordinator to call in clearances for multiple crews	Visioning
C	**External Communications**	
1	**Create an integrated corporate and local communication strategy that is scalable to storm severity.**	KEMA 8 1
2	~~Staff County and State EOC's~~	Governor's AAR
3	Make use of local media and enlist them as partners with a public service perspective	Visioning
4	Identify local media outlets in advance	Visioning
5	Send out electronic messages directly from the EOC to media channels	Visioning
6	Develop culture of openly presenting the picture and setting reasonable outage length estimates, especially in the larger events	Visioning
7	Proactively build pre-storm relationships with local media and elected officials	Visioning
8	Provide early, broad estimates of restoration times for customers	Visioning
9	Provide outage dashboard presentations to cities/counties during storm event (source: CRM debriefing)	Other Int. Debrief
10	Continually update map on pse website showing the progress of work crews	Customer Focus Groups
11	Provide a web-accessible tool for customers to enter an address to get the latest news	Customer Focus Groups
12	Provide ability for customers to send damage information to PSE	Customer Focus Groups

Rec #	Major Recommendation	Recommendation Source
13	Help build community networks to disseminate information through fire stations or put up signs in neighborhoods	Customer Focus Groups
14	Develop a "winter storm warning" best tips magnet for customers to put on refrigerators	Customer Focus Groups
15	Inform customers what substation they depend on and use that when speaking through the media as an efficient way of communicating which areas are up and timelines for others	Customer Focus Groups
16	Assist in setting up local shelters	Customer Focus Groups
17	Use local radio to communicate with customers	Customer Focus Groups
18	Provide outage information and estimated restore times from day 1 in local areas	Customer Focus Groups
19	Post PSE flyers and PSE representatives at police or fire stations	Customer Focus Groups
20	Supply PSE brochures on weather heads and storm restoration flyers in crew trucks	Other Int Debrief
21	Establish times that PSE representative will be on local radio shows to take call-in questions	Customer Focus Groups
D	**Customer Service**	
1	**Formalize a customer escalated call process.**	KEMA 9 1
2	Formalize a customer call/contact escalation process that does not distract resources from restoration efforts and provides a path for communicating to and from field operations and EOC.	Visioning
3	**Use local carrier phone network in front of CLX/IVRU to enhance call-taking capacity and capabilities.**	KEMA 9.2
4	Increase PSE call taking capacity for varying magnitude of storms	Visioning
5	Develop a system that calls customer numbers with updates on a daily basis	Customer Focus Groups
6	Provide an automated call number to put in your phone number to get a progress report and or a nightly call back	Customer Focus Groups
7	Expand call handling to better accommodate requests for specific information and to more fully collect customer comments	Customer Focus Groups
8	Figure out a way to "deputize" the public to help (i e : cut trees etc) for true community partnership	Customer Focus Groups
9	Cut rates or reimburse public for inconvenience because PSE wouldn't give restoration times	Customer Focus Groups
10	Train most employees as reserves to help call center in disaster so they are prepared in advance of storm	Customer Focus Groups
11	At beginning of phone tree, begin by asking if a customer needs to immediately speak with a representative to press zero now (before long phone message)	Customer Focus Groups
12	Provide a voice mail option so you don't have to wait on hold and can get a call back in two hours	Customer Focus Groups
13	Offer low-cost financing for generator operation and maintenance	Customer Focus Groups
14	State on the call center line the state where the call center is located	Customer Focus Groups
E	**Emergency Response - Information Systems**	
1	**Establish enterprise-level technology, data and integration architecture for outage management related processes.**	KEMA 10 1
2	**Develop end-to-end information and business process flows for outage management and emergency restoration processes.**	KEMA 10 2
3	**Enhance existing technology and systems to close functionality gaps and with the strategy of migrating them toward the final architecture.**	KEMA 10 3
4	Accelerate expansion of SCADA coverage and distribution automation	KEMA 10 3
5	Bridge functionality gaps of Cellnet AMI system	KEMA 10 3
6	Integrate low-cost technology (GPS, digital cameras)	KEMA 10 3
7	**Deploy new systems to close the functionality gaps and build out the outage management architecture.**	KEMA 10 4
8	Select and implement an OMS	KEMA 10 4
9	Select and implement a GIS	KEMA 10 4
10	Implement an electronic storm board	KEMA 10 4
11	Select and implement automated switching and restoration workflow tools	KEMA 10 4
12	**Develop a phased implementation plan for outage management related information system and processes.**	KEMA 10.5

Rec #	Major Recommendation	Recommendation Source
13	Identify and implement interim high-value IT enhancements to existing systems	KEMA 10 5
14	Implement key element of final architecture	KEMA 10.5
15	Use commercially available technology to improve restoration estimates and communications.	Visioning
16	Implement an outage management system	Visioning
17	Enhance current AMR technology to provide connectivity with the OMS and better outage information	Visioning
18	Develop electronic storm boards tied to AMR, OMS, and mobile work force	Visioning
19	Automatically interface SCADA into the electronic storm board	Visioning
20	Increase distribution automation and SCADA	Visioning
21	Develop capability to provide restoration information for individual customers	Visioning
22	Develop an automated Emergency Operations Center report with real-time data	Visioning
23	Develop capability to translate outage data into relevant information for customers	Visioning
24	Develop ability to tie multiple outages to one event.	Visioning
25	Develop ability to flag key or critical service customers	Visioning
26	Document, track, prioritize and schedule service orders for secondary lines	Visioning
27	Incorporate damage assessment and repair information into a system that would assist with material acquisition and dispersion	Visioning
28	Implement a system to document track, and prioritize 911 calls for improved response time	Visioning
29	Provide simplified screens for infrequent users of the emergency response tools	Visioning
30	Allow electronic entry when re-energizing a line and completing the job	Visioning
31	Allow damage assessment information to be input directly into a laptop in the field	Visioning
32	Use interactive video feed from Damage Assessors in the field to report specific damage.	Visioning
F	**Service Provider Emergency Response Contract and Processes**	
1	**Refine the ESERSC contract to add the planning, training, communication and evaluation roles necessary to plan for and implement major restoration efforts.**	KEMA 11 1
2	Identify restoration priorities for each operating base	KEMA 11 1
3	Clarify in ESERSC the required communications between EOC and Operations Bases	KEMA 11.1
4	Define SP and PSE roles in the ESERSC to support the CERP	KEMA 11 1
5	Develop SP emergency restoration metrics in the ESERSC	KEMA 11 1
6	Identify information needs for outage restoration estimates	KEMA 11 1
7	Enhance restoration planning training, and drills	KEMA 11.1
8	Include restoration planning, training, and drills in ESERSC	KEMA 11 1
9	Identify specific logistics responsibilities	KEMA 11 1
10	Develop a process to exchange lessons learned	KEMA 11.1
G	**Logistics and Support Services**	
1	**Enhance logistics to better support the number of crews supporting the restoration.**	KEMA 12 1
2	Document logistics support processes	KEMA 12 1
3	Build a formal logistics process map	KEMA 12 1
4	Incorporate logistics support into CERP	KEMA 12 1
5	Identify EOC party responsible for logistics	KEMA 12 1
6	Identify Operations Bases party responsible for logistics	KEMA 12 1
7	Ensure vendor update process is adequate	KEMA 12 1
8	**Document material management policies and processes created to support storm levels.**	KEMA 12 2
9	Document processes to procure materials on short lead time basis	KEMA 12 2
10	Review storm material stocking levels	KEMA 12 2
11	Arrange to store critical materials on site as vendor stock	KEMA 12 2
12	Prearrange expedited shipping	KEMA 12 2
13	Develop plan for resourcing local area coordination centers (trailers tents heat PC s light etc.)	Internal Debrief
H	**Infrastructure Conditions**	

Rec #	Major Recommendation	Recommendation Source
1	**Enhance PSE's transmission vegetation management policy and standards for ROW width.**	KEMA 13 1
2	Foster change in public perception and regulatory policy	KEMA 13 1
3	Map the transmission system problem areas	KEMA 13 1
4	Develop a plan to expand ROWs in hard hit areas	KEMA 13 1
5	Expand TreeWatch to hard hit areas	KEMA 13 1
6	Increase vegetation management in hard hit areas b4 2007-08	KEMA 13 1
7	Increase vegetation management in hard hit areas	KEMA 13 1
8	Ensure access to cross country ROWs b4 2007-08	KEMA 13 1
9	Ensure access to cross country ROWs	KEMA 13 1
10	**Aggressively develop and maintain cross country transmission access roads.**	KEMA 13 2
11	Catalog all existing access roads	KEMA 13 2
12	Develop and fund an access road program	KEMA 13 2
13	Coordinate access road and veg mgt programs	KEMA 13 2
14	**Evaluate hardening opportunities for both transmission and distribution.**	KEMA 13 3
15	**Conduct a system hardening study to determine:**	KEMA 13 3
16	Additional opportunities for UG	KEMA 13 3
17	Use of different towers in hard hit areas	KEMA 13 3
18	Review materials and design standards to match weather	KEMA 13 3
19	Locate transmission lines underground	Customer Focus Groups
20	Increase tree-trimming	Customer Focus Groups

14.4.1

Outside Right-of-Way Tree Risk Along Electrical Transmission Lines

Siegfried Guggenmoos and Thomas E Sullivan

Abstract—For power transmission systems compliant with safety codes and reliability standards there remains a risk of tree-caused interruptions from the in-fall of trees from outside the right-of-way. This paper reports on the quantification of tree exposure outside National Grid's transmission corridors and examines the variables impacting the risk of a line contact by trees. Correlations between the variables and National Grid's tree-caused interruption experience were tested. Regression analysis was applied to a calculated risk factor and the annual interruption frequency.

Two mitigation approaches are compared for cost and efficacy in improving line security. One is based on a regulator suggested use of minimum right-of-way width, while the other is site specific, based on specific site risk versus the voltage class mean risk.

Index Terms-- Power transmission lines, power transmission reliability, prediction methods, reliability management, reliability modeling, tree failure, tree risk, vegetation.

I. Nomenclature

Utility forest: the land base supporting tree growth, which could now or in the future interfere with the transmission or distribution of electricity.

Clear width: the distance from the outside conductor to the tree boles at the forest edge.

Danger tree: any tree which, on failure, is capable of interfering with the safe, reliable transmission of electricity.

Hazard tree: a danger tree that has both a target and a noticeable defect that increases the likelihood of failure.

II. Introduction

THE possibility of a cascading outage event impacting millions of people is a feature intrinsic to the transmission system. The risk of such an event has increased over the last 20 years for several reasons. Foremost among these are that the addition of new lines has all but ceased and transmission systems originally designed to optimize system security on a state or provincial level are now commonly deployed in regional transmission organizations and involved in inter-regional electricity flows. The effect is, there is little or no redundant capacity to tap when a line fails, and lines connecting to other systems, originally designed to protect local systems, are now heavily used for the import/export of electricity.

Trees are a major concern in transmission system reliability. This is powerfully illustrated by the fact that tree-conductor contact (flashover to a tree) was the root cause of these cascading outage events: July 2, 1996 on western grid, 2.2 million customers affected [1]; August 10, 1996 on western grid, 7.5 million customers affected [2]; August 14, 2003 on northeast grid, 50 million customers affected [3]; September 28, 2003 intertie-line between Switzerland and Italy, 60 million customers affected [4].

This history and the August 2003 northeast blackout specifically, have brought considerable scrutiny to utility vegetation management. While it was removed from the final report, one of the questions raised by regulators examining transmission company vegetation management programs following the 2003 blackout was whether there ought to be mandated right-of-way widths based on line voltage [5][6]. We demonstrate by work performed on the National Grid transmission system that while such a requirement may increase line security, it constitutes a very inefficient use of resources. Similar or greater gains in reliability can be achieved for substantially less cost with a program responsive to specific field conditions of above average tree risk.

III. Background Conditions

National Grid owns transmission facilities in New York, Massachusetts, Rhode Island, New Hampshire and Vermont. The lines are located on approximately 7,360 kilometers (4,600 miles) of rights-of-way; 2240 km (1,400 mi) in New England (NE) and 5120 km (3,200 mi) in New York (NY), respectively. Most of these rights-of-way are fully cleared. The rights-of-way contain from one to several circuits, with a voltage range from 69 kV to 345 kV AC and 450 kV DC.

National Grid's vegetation management program has been operated under the centralized control of the Transmission Forestry Department since 1993. The vegetation management program has focused on bringing order and control to vegetation within the rights-of-way (the floor) while removing hazard

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trees from the sides. Reliability of the system has been improved and by a concerted effort to push maintenance operations to the early stages of tree succession, cost efficiencies have been gained. Outage data indicates that tree-caused interruption incidents are due to the failure of trees outside the right-of-way. The incidence of tree-conductor conflicts arising from trees within the right-of-way is virtually non-existent at less than one per year with occurrence restricted to the lower transmission voltages (69 kV and 115 kV).

National Grid's experience is what would be expected for a transmission company compliant with the National Electric Safety Code (NESC) and good utility practice. The NESC requires transmission companies to consider line sag, line swing, flashover and tree growth to maintain adequate clearance between conductors and tree parts so as to avoid any phase-to-ground or phase-to-phase faults. A further focus on right-of-way floor vegetation offers National Grid minimal opportunity for further improvements in system reliability. If National Grid is to achieve a meaningful reduction in tree-caused service interruptions, it needs to better understand the variables affecting off right-of-way tree risk.

The Transmission Forestry Department at National Grid undertook a risk assessment study focused on quantifying the size and characteristics of the utility forest outside the electric utility right-of-way. The goal of the Transmission Forestry Department is to minimize tree-caused interruptions, balanced against financial resources, to improve overall system reliability as measured by number of tree caused incidents and loss of supply to customers. Within this goal, there is a particular focus on higher voltage transmission lines (230 & 345 kV) where National Grid seeks a management plan that results in no tree-caused outages due to the major impact the loss of such a line could have and the associated risk of system instability. This goal is consistent with the reliability standards emerging in response to the 2003 northeast blackout. The project was designed to provide the Transmission Forestry Department the data required to quantify the current level of tree risk and thereafter to develop and assess the cost of a range of mitigation options.

IV. Methods

The project involved a number of phases. The key aspects can be summarized as the random selection of 400 right-of-way points where the percent of treed edge, right-of-way characteristics such as line height, tree height, clear width and adjacent forest characteristics were collected. The percent of forested edge was derived from aerial photographs within National Grid's GIS. Aerial photographs were available for 377 of the 400 random sample points. Literature on major storm damage to trees was researched to assess tree failure modes and identify what species represent the largest risk to transmission service in the US northeast. Weather events from 1950 through 2003 were compiled by county, to determine the frequency of tree damaging events. The frequency of tree damaging weather events and the specifics of tree species vulnerabilities are not presented in this article.

The fieldwork collected data on 131 sample points in New England (NE) and 178 points in New York (NY). Some of the 400 random sampling points could not be used, as there was no adjacent forest. There was no 69 kV sampled in NY. For the forest data, which identified the tree species, measured the diameter at breast height (dbh) of trees falling within a BAF10 prism sample and identified the cover type, over 22,000 records were generated.

Field data collection occurred from January 2004 through mid-July. Due to the timing of data collection and that National Grid experiences peak loads in response to air conditioning demand, the vast majority of the measured line heights do not reflect a maximum sag condition.

Analysis involved the use of the Optimal Clear Width Calculator [7] (OCWC), which through triangulation determined whether off right-of-way trees were capable of interfering (danger trees) with the transmission system, and provided a measure of the extent of the risk. In this way distinctions could be made between the total tree exposure and the tree exposure comprised of trees tall enough to strike a conductor on failure, thereby constituting a current risk to the transmission system. Also assessed and analyzed were forest cover types, species composition, and the incidence of emergent (dominant) trees. Data on forest cover types and species composition are not presented in this article with one exception relevant to emergent (dominant) trees. The measured variables of line height, tree height, clear width and the derived tree risk are examined in relation to the history of tree-caused outage incidents.

The quantification of a particular vulnerability, that of forest stands where a tree species is emergent (dominant) above the general tree canopy (co-dominant), was an identified focus of the study. Trees emergent to the canopy are more susceptible to lightning strikes; wind; wet snow and ice stress loadings and, therefore, are more susceptible to failure.

V. Results

In both NE and NY White Pine was the predominant current emergent species, occurring along 12.4% and 8.5% respectively, of the right-of-way edge. The risk posed by emergent trees has the potential to expand substantially over the next 30 years, especially in the NY service area, as the amount of the utility forest containing White Pine is 20.4% in NE and 27.2% in NY.

A. Utility Forest Beyond the Right-of-Way

Total current tree exposure was determined from the size of the utility forest times the tree density. One of the variables necessary to estimate the size of the utility forest is a measure of length or the extent of treed (forested) edge. The other, the measure of depth was derived by triangulation using mean tree height, line height and clear width.

The percent of treed right-of-way edge is 77.46 ± 3.1 in NE and 61.83 ± 2.93 in NY. The total treed right-of-way edge is 3456 ± 138 km (2160 ± 86 mi) in NE and 6336 ± 300 km (3960 ± 188 mi) in NY. The land base for the utility forest beyond the right-of-way is 1390 ha (3447 acres) in NE and 2108 ha (5227 acres) in NY. Not all of the treed edge is a current liability. The utility forest component with current potential for tree-conductor conflicts is 1931 km of right-of-way edge of 4621 km (1,207 miles of 2,888) in NE and 2488 km of right-of-way edge of 10,246 km (1,555 miles of 6,404) in NY.

Tree density was found to be 491 ± 15 trees per ha (198 ± 6 trees per acre) (Table I). Using this finding, the total danger tree exposure was calculated to be 642,874 trees in NE and 795,770 in NY at the estimated maximum conductor sag position. At the maximum conductor sag position the number of danger trees per kilometer of right-of-way edge is 148 (236 mi^{-1}) in NE and 77 (123 mi^{-1}) in NY. Annual mortality was derived using stand data for the closest permanent sample plots (Allegheny Forest in Pennsylvania) used in the Forest Vegetation Simulator (FVS) [8] in a mortality modeling algorithm [7]. Hazard tree development based on the derived annual mortality rate is 1.9 (3 mi^{-1}) trees in NE and 1.3 (2 mi^{-1}) trees in NY per kilometer of right-of-way edge. If the average number of hazard trees identified and removed on an annual basis falls below the expected mortality, then it is likely that there is an increasing but as yet unrecognized population of hazard trees. Over time, this unrecognized hazard will become susceptible to failure under progressively less stress loading [9].

TABLE I
TREE DENSITY BY OPERATING AREA (TREES/HECTARE)

	Trees Per hectare	Trees Per hectare (>10 cm dbh)
NE	1218 ± 149	491 ± 25
NY	1074 ± 92	489 ± 20
All	1131 ± 82	491 ± 15

Fig. 1 provides the size of National Grid's off right-of-way utility forest in both hectares and trees per km. The hectares of utility forest are derived from the number of hectares per km times the number of km for the voltage class. The data in Fig. 1 provides National Grid with measures of the scale of the undertaking if the risk associated with trees beyond the right-of-way is to be managed.

Variable means were compared by voltage class within each operating area (Student-Newman-Keuls, p=0.05). Fig. 2 shows the mean clear width, with the associated confidence interval. Letters above the bars provide the results of significance tests. Means for NE are tested independent of NY means. The data for NE shows an overlap in the clear width for 115 kV, 230 kV and 345 kV lines and there is no significant difference. The data indicates that while right-of-way widths and thereby, clear widths are greater for higher voltage lines, significant differences in mean clear widths occur only relative to the lowest voltage class.

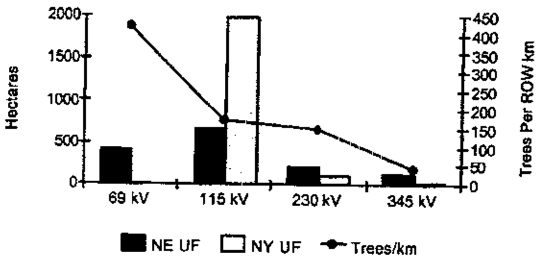

Fig 1 Utility Forest Beyond ROW

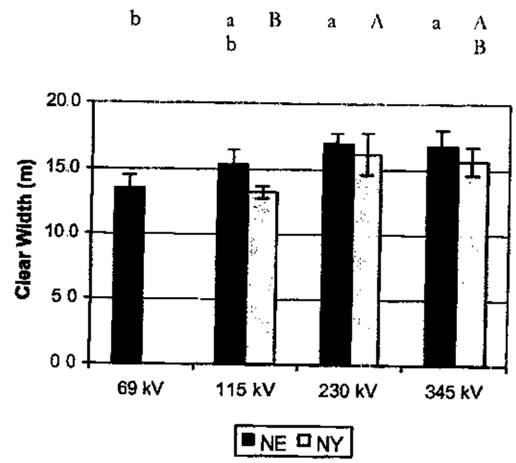

Fig 2 National Grid Transmission Clear Width

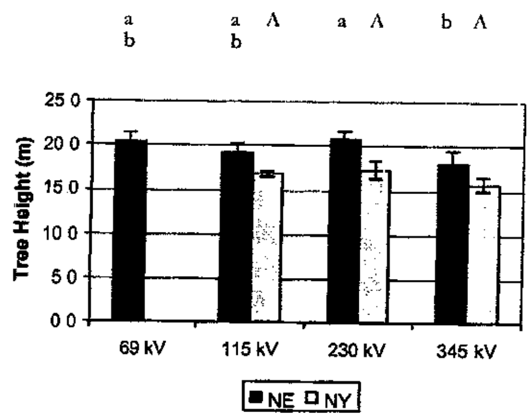

Fig 3. Mean Tree Height

One would not expect significant differences in mean tree height between voltage classes as the choice of line voltage installed is based on needs independent of tree height along the route (Fig 3).

There is a clear trend of increasing line height for higher voltages in NE and the 345 kV lines in NY were found to have a significantly greater ground clearance (Fig. 4).

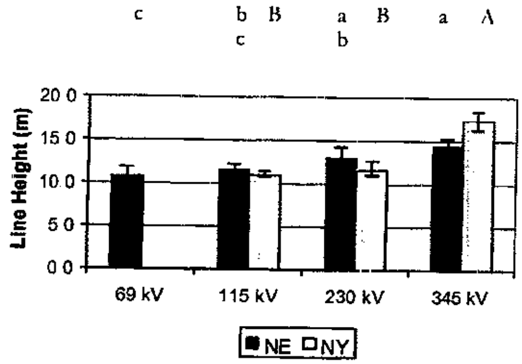

Fig 4. Mean Line Height

Examining where significant differences between means for line height, tree height and clear width occur, it is difficult to assess the extent of difference in risk exposure and whether such differences would yield significantly different interruption incidents between voltage classes.

TABLE 2
AVERAGE TREE RISK FACTOR (%) AT FOUND SAG

	NE	NY
All voltages	5.99	4.98
69 kV	10.28 a	-
115 kV	6.02 b	6.19 A
230 kV	3.78 bc	2.30 B
345 kV	2.12 c	0.19 B

The use of the Risk Factor (RF) generated by the OCWC reduces these three variables plus tree density to one value. The RF (Table 2, Fig. 5) shows a very orderly decrease in tree risk with increasing voltage. These differences, however, are not large enough to provide a distinct risk profile for each voltage class (Table 2).

The correlation between variables and voltage class was determined. The correlation between voltage class and the variables of clear width (r=0.1669), line height (r=0.2705) and Risk Factor (r=0.2934) (Fig. 5) were significant. There was no significance found for the correlation of voltage class to tree height (-0.0592) and trees per acre (-0.0048). The correlations confirm expectations. Higher voltage lines are constructed with greater ground clearance within wider right-of-ways. The magnitude and need for electrical load arises independent of forest characteristics such as tree height and density.

Tree-caused interruption experience was examined. In NE nine years of data was available while NY had only 4 years of data. Of the 72 incidents recorded, 97% occurred on the 69 kV and 115 kV circuits. The remaining 3% occurred on 230 kV in NE. There were no tree incidents on NE 345 kV, NY 230 kV and NY 345 kV lines.

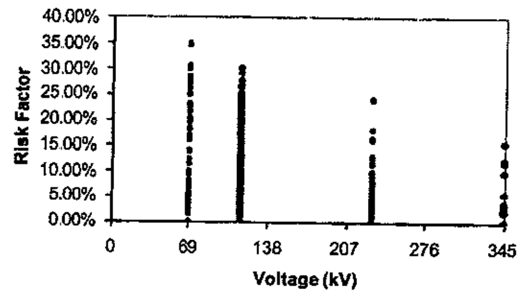

Fig. 5 Scatter Diagram Risk Factor vs. Voltage

VI. DISCUSSION

A Variable Correlation to Outage Experience

National Grid's objective for this study was to gain insight into mitigating tree-caused service interruptions arising from tree failures outside the right-of-way. This requires both a means to rate the current vulnerability of a specific line or location to tree-caused interruptions and to reasonably predict interruption frequency after treatment. National Grid has used the OCWC to assess current and future tree risk. Tree risk after treatment had not been correlated to interruption frequency.

The magnitude of the voltage class RF means in Table 2 are aligned with National Grid's tree-caused outage experience. To further test the viability of a number of variables as predictors of future transmission system performance the correlation between their means and National Grid's tree-caused interruption experience was tested. Different time frames of outage history between operating areas, necessitated the tree-caused outage data to be expressed as an annual interruption frequency. The results are presented in Table 3.

TABLE 3
VARIABLE RELATION TO INTERRUPTION EXPERIENCE

Variable (means)	Correlation Coefficient (r)	P(r=0)
Tree Height	0.0833 ns	0.8591
Line Height	-0.6003 ns	0.1541
Clear Width	-0.9128 **	0.0041
Total Tree Exposure	0.8441 *	0.0169
Trees/km ROW Edge	0.5770 ns	0.1750
Risk Factor	0.8124*	0.0264

ns not significant

Generally, the correlation coefficients in Table 3 meet expectations. Line height and clear width are negatively correlated as increases in these variables reduce the line exposure to trees. The weak and non-significant correlation of mean tree height to interruption experience is unexpected. However, no data on tree height for actual the outage incidents was provided. It is not known if mean tree heights used in this analysis accurately represent the height of failed trees giving rise to outage incidents

Measures of the tree exposure, such as total exposure and tree per km of ROW edge, serve to bring some clarity to the magnitude of the danger tree risk and the operational challenges. Of these two variables, only total tree exposure was found to be significantly correlated to the total number of tree-caused incidents (Table 3).

Comparing trees per km of ROW edge to tree-caused interruption frequency, however, fails to consider the length of line per voltage class To put both the trees and tree incidents on a unit length basis it was necessary to transform the data to yield the number of tree-caused outage incidents per unit line length. In this case the chosen unit is per 1,000 kms. A significant correlation between annual outage incidents per 1000 kms and trees per km of ROW edge exists, with r =0.8691 and P(r=0)=0.0111. The implications are that the number of tree-caused interruptions is directly related to the amount of tree exposure.

RF, which incorporates the variables of line height, tree height, clear width and tree density, was found to have a significant correlation to tree-caused interruptions, with an r-value of 0.8124 (Table 3). Due to regional differences in the extent of tree cover the data was segregated by operating area prior to regression of the RF for annual outage incidents per 1000 kms. Various regression equations were tested, with the Exponential regression form yielding the lowest P in ANOVA (P=0.0035) and the smallest residuals. Regression analysis was undertaken only for the more comprehensive outage data set of NE, yielding (1).

$$F_{AI} = 0.13424751\ 967 \times e^{(40.2108865\ 236 \times \mathrm{RF})} \qquad (1)$$

where F_{AI} is annual interruption frequency and RF is Risk Factor as produced by the Optimal Clear Width Calculator [7]

The annual interruption frequency for 230 kV is 0.22yr^{-1} An interruption is expected to occur once in 4 to 5 years. No tree-caused outages have been experienced on the 345 kV lines. The 345 kV lines are not devoid of tree risks as indicated by the found RF of 0.0212. If the RF 0.0321 based on maximum conductor sag of the NE 345 kV lines is used, the expectation for tree-caused outages is F_{AI}=0 136659 or 1 incident in 8 years.

B. Mitigation

Although, the RF ratings (Table 2) indicate an operational responsiveness to the adjacent forest conditions, one of the main observations of this work is the wide range of variability in the RF within any given voltage class. An examination of the data for 345 kV lines illustrates the variability in tree risk There are 83 sample records. Of these, 72 records have a tree RF of 0% There are 8 records where the RF exceeds 2.5% (Table 4). This led to an examination of the potential impact on line security of addressing only the areas of high tree risk with comparisons of efficacy and costs to a suggested regulatory approach of a specified minimum right-of-way width based on voltage The strong correlation found between National Grid's interruption experience and mean clear width segregated by voltage class (Table 3), indicates the suggested regulatory approach of specifying a minimum right-of-way width to manage tree-caused outages is supported, on National Grid's transmission system.

TABLE 4
VARIABILITY IN TREE RISK FACTOR FOR 345 KV

Operating Area	Sample Pt. No.	Line No.	Risk Factor (%)
NE	2	303	3.80
NE	8	394	15.46
NE	44	343	12.16
NE	64	394	11.64
NE	99	394	11.81
NE	131	394	3.23
NE	139	315	5.69
NY	37	4	9.69

TABLE 5
TREE FREE CLEAR WIDTH FOR MEAN CONDITIONS

Voltage	Mean Risk Factor (%) At Maximum Sag	Current Mean Clear Width (m)[1]	Tree Free Clear Width (m)[2]	Tree Free Based On Tallest Tree Found Clear Width (m)[3]
69 kV	11 95	13.3	25.5	34.8
115 kV	7.39	14.2	20.3	32.4
230 kV	4.34	16.3	23.6	29.7
345 kV	1.71	15.8	20.3	31 5

[1] For right-of-way width double the clear width and add the distance between outside conductors i.e. for 69 kV = 13 3 X2 + 3 7 = 30 3m
[2] This is the clear width required to achieve tree free on the average line. Lines facing above average tree exposure will not be tree free.
[3] The clear width that would actually achieve a tree free condition based on data of tallest trees found within the samples.

In undertaking this comparison it is necessary to assume what the minimum regulator specified right-of-way width might be. This assumption is made using the data from the National Grid system (Table 5). Using 345 kV lines to explore the merits of the approaches to managing tree risk, a clear width of 20 3 m (67 ft) (Table 5) would make the average 345 kV line tree free. Setting the clear width based on the average condition found for 345 kV lines does not reduce the risk of tree incidents to zero. Based on tallest tree encountered in the sampling a zero tree risk is only achieved at a 31.5 m (104 ft) clear width (Table 5), which equals a right-of-way width of 63 m (208 ft) plus the distance between outside conductors Any new tree growth will serve to increase the required clear width. It was assumed that regulators might require all the 345 kV lines to have a minimum clear width of 21.2 m (70 ft). On this basis of this assumption, 89% of National Grid's 345 kV transmission system requires widening. However, 69% of the samples with a clear width of less than 21.2 m, currently have a RF rating of 0%. While the overall improvement in line security of increasing the clear width to 21.2 m from the current 15.8 m (52 ft) (Table 5) is 78%, the majority of this widening (i.e 69%) will yield no improvement.

Using the RF ratings, a site-specific treatment approach was developed. It is comprised of reducing the tree risk of all spans to the voltage class average RF, which is 1.71% (NE & NY) at estimated maximum sag for 345 kV lines Only 20% of the samples had a RF above the average. However, the average RF for these anomalous sites is 8.27%, with F_{AI}=3.7336. Increasing clear width, line height or reducing tree height to bring the RF at these sites down to the average will improve overall line security 79% and in so doing, reduce the voltage class average RF to 0.36%. The F_{AI} is shifted to 0.1552 (under normal operating conditions) or an expected tree-caused incident frequency of 1 in 23 years.

Similar analysis of the other voltage classes leads to the same conclusion. On National Grid's transmission system, managing tree risk through the use of minimum clear widths based on voltage class constitutes an inefficient use of resources, costing 30-70% more than using site-specific prescriptions, which reduce the RF to at least the voltage class average

The use of a tree RF provides a quantifiable approach to managing tree risk. One of the key findings of the work to assess the beyond right of way tree exposure of National Grid's transmission system is that there are areas of anomalous tree risk, substantially higher than the average for the voltage class. This observation is a product of having produced a RF rating for each sample point edge. Because the RF is responsive to the actual field conditions, it identifies where a dedication of resources will yield the greatest return in avoided tree-caused interruptions.

Aspects of this work may be extended to other utilities. For example, given the range of possible variability in tree height and density and, to a lesser extent in clear width and line height, the finding that the economics of a site-specific approach to managing tree risk proves superior to the use of standardized clear widths based on voltage, will hold true. The RF is a measure of tree exposure, while the outage experience provides the information on vegetation failure rates. This work has demonstrated a strong correlation between the RF produced by the OCWC and tree-caused interruptions. The methodology is transferable to other utilities. However, due to differences in tree species and their associated failure rates and modes of failure, the regression equation (1) cannot be expected to be applicable to other utilities, unless they are located in the same geographic area as the National Grid transmission system. For other utilities the relationship between a measure of the tree risk, which reflects local tree conditions, and the tree-caused interruption experience will need to be established.

VII REFERENCES

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VIII. BIOGRAPHIES

Siegfried Guggenmoos received the honors B.Sc. degree in agriculture, horticulture major, from the University of Guelph, Guelph, ON in 1977.

He is the president of Ecological Solutions Inc., a vegetation management and biotic greenhouse gas sequestration consultancy in Sherwood Park, AB, Canada. He has been in the vegetation management field for over 30 years with roles in research, management of a vegetation management contracting company, utility forestry and consulting.

Mr Guggenmoos is a member of the Alberta Institute of Agrology, the Agricultural Institute of Canada, the International Society of Arboriculture, the Utility Arborist Association, the Industrial Vegetation Management Association of Alberta and IEEE

Thomas E. Sullivan received a MA in biology in 1977 from Boston University Boston, MA and a B.Sc in Forestry, from State University of New York, Syracuse, NY in 1978,

He is the Manager Transmission Forestry National Grid, in Westborough, MA.

Mr Sullivan is a member of the Society of American Foresters, the International Society of Arboriculture, the Utility Arborist Association, and the Nature Conservancy

EXHIBIT B

Data Request #54

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-072300 and UG-072301
Puget Sound Energy, Inc.'s
2007 General Rate Case

WUTC STAFF DATA REQUEST NO. 054

"CONFIDENTIAL" Table of Contents

DR NO.	"CONFIDENTIAL" Material
054	The ______________ in WUTC Staff Data Request No. 054 is CONFIDENTIAL/HIGHLY CONFIDENTIAL per Protective Order in WUTC Docket No. UE-072300 / UG-072301 and per WAC 480-07-160

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Docket Nos. UE-072300 and UG-072301
Puget Sound Energy, Inc.'s
2007 General Rate Case

WUTC STAFF DATA REQUEST NO. 054

WUTC STAFF DATA REQUEST NO. 054:

Re: Hanukah Storm Report Exhibit No. __(GJZ-9) (Witness: Greg Zeller)

On pages 136 through 140 of 146 under Recommendation 13.4.1, PSE provides a master task list of recommendations that came from PSE's internal storm debriefs, the Governor's After Action Review and from customer focus groups and survey input. Please sort these recommendations based on the description of categories found at the top of page 20 of 146, *i.e.*, actions that could be accomplished for the 2007-08 storm season, what may be accomplished by the 2008-09 storm season, and those that are longer term initiatives. Please indicate which recommendations were completed or implemented as listed and those yet to be implemented.

Response:

Attached as Attachment A to Puget Sound Energy, Inc.'s ("PSE's") Response to WUTC Data Request No. 052 is the Recommendations Matrix for 13.4.1 with columns added noting which tasks were anticipated by the internal team working on recommendations 1) to be accomplished for the 2007-08 storm season, 2) under consideration for accomplishment by our 2008-09 storm season, and 3) those that are under consideration for longer-term initiatives.

Those noted on the Attachment A to PSE's Response to WUTC Data Request No. 052 are highlighted in grey have been completed.

Date of Response: February 13, 2008
Person who Prepared the Response: Mary Robinson
Witness Knowledgeable About the Response: Greg Zeller

ATTACHMENT A to PSE's Response to WUTC Staff Data Request No. 054

Recommendations Matrix
Grey Highlight = Completed

Rec #	Major Recommendation	Recommendation Source	To Accomplish by 2007-08 Storm Season	Under Consideration for Accomplishment by 2008-09 Storm Season	Under Consideration for Longer Term Initiative
A	**Emergency Response Planning and Structure**				
1	Enhance PSE employees emergency response planning and execution capability (add 1-2 FTE's to Operations Continuity to support storm plan improvement recommendations)	Storm Team	X (not yet approved)		
2	**Enhance emergency response training**	KEMA 4.1	X		
	a) damage assessor training				
	b) contract crew coordinator training				
	c) 911 call taker training				
	d) CLX training				
	e) Lodging coordinator training - new 2007/08				
	f) County/State EOC liaison training - new 2007/08				
3	Clarify ownership of emergency response responsibilities	KEMA 4.1	X		
4	Expand PSE participation in County EOCs	KEMA 4.1	X		
5	Develop succession plan for key positions	KEMA 4.1		X	
6	Stock additional radios for foreign crews at storm bases	Internal Debrief	X		
7	Increased radio frequency channels	Other Int. Debrief	X		
8	Increase radio capacity	Visioning	X		
9	Provide additional cell phones that will work when power supplies are out	Visioning	X		
10	Stock adequate quantities of storm bags in operating bases	Internal Debrief	X		
11	Develop checklist for staging areas	Internal Debrief	X		
12	Develop checklist for foreign crew contracting: materials, equipment, etc.)	Internal Debrief	X (in progress 1/31/08)		
13	Develop plan for opening Whidbey Operating Base as appropriate: (staffing & triggers)	Internal Debrief	X		
14	Formalize role of lodging coordinators in plan	Internal Debrief	X		
15	Develop a storm categorization methodology and tailor aspects of the CERP to the various levels of storms.	KEMA 5.1	X		

Rec #	Major Recommendation	Recommendation Source	To Accomplish by 2007-08 Storm Season	Under Consideration for Accomplishment by 2008-09 Storm Season	Under Consideration for Longer Term Initiative
16	Build a storm database that tracks damage and restoration	KEMA 5.1		X	
17	Document historical damage by area	KEMA 5.1		X	
18	Develop initial process for early storm restoration estimates	KEMA 5.1	X		
19	Develop process for early storm restoration estimates	KEMA 5.1		X	
20	Increase the number of trained system operators to improve switching times	Visioning		X	
21	Reinforce management support for employee participation in storm restoration.	Visioning	X		
22	Identify and train additional qualified and skilled employees for key emergency response roles including damage assessors, crew coordinators, dispatchers, system operators, data entry, customer service representatives, and community representatives.	Visioning	X		
23	Provide more circuit map books to Operations Bases	Other Int. Debrief	X		
24	Provide more PSE all-wheel drive SUV's	Other Int. Debrief	X		
25	Assemble a list of electrical contractors who can do weather head or homeowner emergency type of work to not leave customers hanging on weekends or holidays in future	Other Int. Debrief		X	
26	Provide Company issued gear (hats/coats, etc) for all employees working storm	Other Int. Debrief			X
27	Develop plan for fueling equipment when emergencies make it difficult to get gas	Other Int. Debrief		X	
28	For accountability, hire local people to work in their communities (don't make someone drive to Bremerton to do damage assessment who lives in Puyallup)	Customer Focus Groups		X	
B	**Emergency Restoration Execution**				
1	Enhance Damage Assessor training	KEMA 6.1	X		

Recommendations Matrix
Grey Highlight = Completed

Rec #	Major Recommendation	Recommendation Source	To Accomplish by 2007-08 Storm Season	Under Consideration for Accomplishment by 2008-09 Storm Season	Under Consideration for Longer Term Initiative
2	Revise DA process for estimating restoration and crew requirements	KEMA 6.1		X	
3	Formalize field DA process to produce more consistent and actionable information	KEMA 6.1	X		
4	Enhance PSE DA support capability	Team		X	
5	Benchmark DA process best practices	Team			X
6	Streamline safety orientations for foreign crews	Internal Debrief	X		
7	Expand use of GPS for crews, damage assessors, crew coordinators	Internal Debrief	X		
8	Enhance 911 call taker training and process to triage 911 calls	Internal Debrief	X		
9	Develop plan to deploy additional helicopters for patrolling, damage assessment	Internal Debrief	X		
10	Develop strategy to increase # of qualified flaggers available	Internal Debrief	X		
11	Pursue WA State flagging certification exemption	Internal Debrief		X (with Disaster Declaration by Governor)	
12	Formalize "utility road clearing task force" with DOT, County/City Roads, PSE, Potelco and Asplundh	Governor's AAR	X (still in progress 1/31/08)		
13	Request HOV lane exemption from State Patrol	Governor's AAR	X		
14	Work with State EMD to obtain Governor's Declaration of Disaster	Governor's AAR	X		
15	Review operating base management process	KEMA 7.1	X		
16	Establish emergency restoration perfomance metrics	KEMA 7.1		X	
17	Clarify emergency response roles of PSE and SP	KEMA 7.1	X		
18	**Formalize local area coordination and transmission restoration priority activities.**	KEMA 7.2	X		
19	Formalize and document local area coordination	KEMA 7.2	X		
20	Develop Local Area Coordination Plan	KEMA 7.2		X	
21	Establish triggers to launch Local Area Coordination	KEMA 7.2	X		

Rec #	Major Recommendation	Recommendation Source	To Accomplish by 2007-08 Storm Season	Under Consideration for Accomplishment by 2008-09 Storm Season	Under Consideration for Longer Term Initiative
22	Develop Local Area Coordination clearance procedures	KEMA 7.2	X		
23	Develop process for triggering "transmission restoration priority teams" including communications to field and operations bases	Internal Debrief	X		
24	Investigate increasing use of self-protected clearance to relieve system operations congestion	Visioning	X		
25	Investigate using a qualified local area crew coordinator to call in clearances for multiple crews	Visioning	X		
C	**External Communications**				
1	**Create an integrated corporate and local communication strategy that is scalable to storm severity.**	KEMA 8.1	X		
2	Staff County and State EOC's (See A4)	Governor's AAR	X		
3	Make use of local media and enlist them as partners with a public service perspective.	Visioning	X		
4	Identify local media outlets in advance.	Visioning	X		
5	Send out electronic messages directly from the EOC to media channels.	Visioning		X	
6	Develop culture of openly presenting the picture and setting reasonable outage length estimates, especially in the larger events.	Visioning	X		
7	Proactively build pre-storm relationships with local media and elected officials.	Visioning	X		
8	Provide early, broad estimates of restoration times for customers.	Visioning	X		
9	Provide outage dashboard presentations to cities/counties during storm event (source: CRM debriefing)	Other Int. Debrief	X		

Recommendations Matrix
Grey Highlight = Completed

Rec #	Major Recommendation	Recommendation Source	To Accomplish by 2007-08 Storm Season	Under Consideration for Accomplishment by 2008-09 Storm Season	Under Consideration for Longer Term Initiative
10	Continually update map on pse website showing the progress of work crews	Customer Focus Groups	X (map available; progress of work crews still under consideration)		
11	Provide a web-accessible tool for customers to enter an address to get the latest news	Customer Focus Groups			X
12	Provide ability for customers to send damage information to PSE	Customer Focus Groups			X
13	Help build community networks to disseminate information through fire stations or put up signs in neighborhoods	Customer Focus Groups		X	
14	Develop a "winter storm warning" best tips magnet for customers to put on refrigerators	Customer Focus Groups			X
15	Inform customers what substation they depend on and use that when speaking through the media as an efficient way of communicating which areas are up and timelines for others	Customer Focus Groups			X
16	Assist in setting up local shelters	Customer Focus Groups			X
17	Use local radio to communicate with customers	Customer Focus Groups	X		
18	Provide outage information and estimated restore times from day 1 in local areas	Customer Focus Groups		X	
19	Post PSE flyers and PSE representatives at police or fire stations	Customer Focus Groups		X	
20	Supply PSE brochures on weather heads and storm restoration flyers in crew trucks	Other Int. Debrief	X (to move to 2nd 1/2 year 2008)		
21	Establish times that PSE representative will be on local radio shows to take call-in questions	Customer Focus Groups			X

Rec #	Major Recommendation	Recommendation Source	To Accomplish by 2007-08 Storm Season	Under Consideration for Accomplishment by 2008-09 Storm Season	Under Consideration for Longer Term Initiative
D	**Customer Service**				
1	**Formalize a customer escalated call process.**	KEMA 9.1	X		
2	Formalize a customer call/contact escalation process that does not distract resources from restoration efforts and provides a path for communicating to and from field operations and EOC.	Visioning	X		
3	**Use local carrier phone network in front of CLX/IVRU to enhance call-taking capacity and capabilities.**	KEMA 9.2	X (to move to 2nd 1/2 year 2008)		
4	Increase PSE call taking capacity for varying magnitude of storms	Visioning	X		
5	Develop a system that calls customer numbers with updates on a daily basis	Customer Focus Groups			X
6	Provide an automated call number to put in your phone number to get a progress report and or a nightly call back	Customer Focus Groups			X
7	Expand call handling to better accommodate requests for specific information and to more fully collect customer comments	Customer Focus Groups	X		
8	Figure out a way to "deputize" the public to help (i.e.: cut trees, etc) for true community partnership	Customer Focus Groups			X
9	Cut rates or reimburse public for inconvenience because PSE wouldn't give restoration times	Customer Focus Groups			X
10	Train most employees as reserves to help call center in disaster so they are prepared in advance of storm	Customer Focus Groups	X		
11	At beginning of phone tree, begin by asking if a customer needs to immediately speak with a representative to press zero now (before long phone message)	Customer Focus Groups		X	
12	Provide a voice mail option so you don't have to wait on hold and can get a call back in two hours	Customer Focus Groups			X

Rec #	Major Recommendation	Recommendation Source	To Accomplish by 2007-08 Storm Season	Under Consideration for Accomplishment by 2008-09 Storm Season	Under Consideration for Longer Term Initiative
13	Offer low-cost financing for generator operation and maintenance	Customer Focus Groups			X
14	State on the call center line the state where the call center is located	Customer Focus Groups			X
E	Emergency Response - Information Systems				
1	**Establish enterprise-level technology, data and integration architecture for outage management related processes.**	KEMA 10.1			X
2	**Develop end-to-end information and business process flows for outage management and emergency restoration processes.**	KEMA 10.2			X
3	**Enhance existing technology and systems to close functionality gaps and with the strategy of migrating them toward the final architecture.**	KEMA 10.3		X	
4	Accelerate expansion of SCADA coverage and distribution automation	KEMA 10.3		X	
5	Bridge functionality gaps of Cellnet AMI system	KEMA 10.3		X	
6	Integrate low-cost technology (GPS, digital cameras)	KEMA 10.3		X	
7	**Deploy new systems to close the functionality gaps and build out the outage management architecture.**	KEMA 10.4			X
8	Select and implement an OMS	KEMA 10.4			X
9	Select and implement a GIS	KEMA 10.4			X
10	Implement an electronic storm board	KEMA 10.4			X
11	Select and implement automated switching and restoration workflow tools	KEMA 10.4			X
12	**Develop a phased implementation plan for outage management related information system and processes.**	KEMA 10.5			X
13	Identify and implement interim high-value IT enhancements to existing systems	KEMA 10.5			X

Recommendations Matrix
Grey Highlight = Completed

Rec #	Major Recommendation	Recommendation Source	To Accomplish by 2007-08 Storm Season	Under Consideration for Accomplishment by 2008-09 Storm Season	Under Consideration for Longer Term Initiative
14	Implement key element of final architecture	KEMA 10.5			X
15	Use commercially available technology to improve restoration estimates and communications.	Visioning	X (determined to be longer term project)		
16	Implement an outage management system	Visioning			X
17	Enhance current AMR technology to provide connectivity with the OMS and better outage information.	Visioning			X
18	Develop electronic storm boards tied to AMR, OMS, and mobile work force.	Visioning			X
19	Automatically interface SCADA into the electronic storm board.	Visioning			X
20	Increase distribution automation and SCADA	Visioning			X
21	Develop capability to provide restoration information for individual customers.	Visioning			X
22	Develop an automated Emergency Operations Center report with real-time data	Visioning			X
23	Develop capability to translate outage data into relevant information for customers	Visioning	X		
24	Develop ability to tie multiple outages to one event.	Visioning		X	
25	Develop ability to flag key or critical service customers.	Visioning		X	
26	Document, track, prioritize and schedule service orders for secondary lines.	Visioning			X
27	Incorporate damage assessment and repair information into a system that would assist with material acquisition and dispersion	Visioning		X	
28	Implement a system to document, track, and prioritize 911 calls for improved response time.	Visioning		X	
29	Provide simplified screens for infrequent users of the emergency response tools.	Visioning		X	
30	Allow electronic entry when re-energizing a line and completing the job.	Visioning			X

Rec #	Major Recommendation	Recommendation Source	To Accomplish by 2007-08 Storm Season	Under Consideration for Accomplishment by 2008-09 Storm Season	Under Consideration for Longer Term Initiative
31	Allow damage assessment information to be input directly into a laptop in the field.	Visioning		X	
32	Use interactive video feed from Damage Assessors in the field to report specific damage.	Visioning			X
F	**Service Provider Emergency Response Contract and Processes**				
1	**Refine the ESERSC contract to add the planning, training, communication and evaluation roles necessary to plan for and implement major restoration efforts.**	KEMA 11.1	Per PSE Report to UTC filled 11/28/07, PSE did not accept KEMA's recommendation.		
2	Identify restoration priorities for each operating base	KEMA 11.1	X		
3	Clarify in ESERSC the required communications between EOC and Operations Bases	KEMA 11.1	see F1		
4	Define SP and PSE roles in the ESERSC to support the CERP	KEMA 11.1	see F1		
5	Develop SP emergency restoration metrics in the ESERSC	KEMA 11.1	see F1		
6	Identify information needs for outage restoration estimates	KEMA 11.1		X	
7	Enhance restoration planning, training, and drills.	KEMA 11.1	X		
8	Include restoration planning, training, and drills in ESERSC	KEMA 11.1	see F1		
9	Identify specific logistics responsibilities	KEMA 11.1		X	
10	Develop a process to exchange lessons learned	KEMA 11.1		X	
G	**Logistics and Support Services**				
1	**Enhance logistics to better support the number of crews supporting the restoration.**	KEMA 12.1	X		

Rec #	Major Recommendation	Recommendation Source	To Accomplish by 2007-08 Storm Season	Under Consideration for Accomplishment by 2008-09 Storm Season	Under Consideration for Longer Term initiative
2	Document logistics support processes	KEMA 12.1	X		
3	Build a formal logistics process map	KEMA 12.1	X		
4	Incorporate logistics support into CERP	KEMA 12.1	X		
5	Identify EOC party responsible for logistics	KEMA 12.1	X		
6	Identify Operations Bases party responsible for logistics	KEMA 12.1	X		
7	Ensure vendor update process is adequate	KEMA 12.1	X		
8	**Document material management policies and processes created to support storm levels.**	KEMA 12.2	X		
9	Document processes to procure materials on short lead time basis	KEMA 12.2	X		
10	Review storm material stocking levels	KEMA 12.2	X		
11	Arrange to store critical materials on site as vendor stock	KEMA 12.2			X
12	Prearrange expedited shipping	KEMA 12.2	X		
13	Develop plan for resourcing local area coordination centers (trailers, tents, heat, PC's, light, etc.)	Internal Debrief	X		
H	**Infrastructure Conditions**				
1	**Enhance PSE's transmission vegetation management policy and standards for ROW width.**	KEMA 13.1		X	
2	Foster change in public perception and regulatory policy	KEMA 13.1			X
3	Map the transmission system problem areas	KEMA 13.1		X	
4	Develop a plan to expand ROWs in hard hit areas	KEMA 13.1		X	
5	Expand TreeWatch to hard hit areas	KEMA 13.1		X	
6	Increase vegetation management in hard hit areas before 2007-08	KEMA 13.1	X		
7	Increase vegetation management in hard hit areas	KEMA 13.1		X	
8	Ensure access to cross country ROWs before 2007-08	KEMA 13.1	X (See PC DR 107)		
9	Ensure access to cross country ROWs	KEMA 13.1		X	
10	**Aggressively develop and maintain cross country transmission access roads.**	KEMA 13.2		X	

Recomme..dations Matrix
Grey Highlight = Completed

Rec #	Major Recommendation	Recommendation Source	To Accomplish by 2007-08 Storm Season	Under Consideration for Accomplishment by 2008-09 Storm Season	Under Consideration for Longer Term Initiative
11	Catalog all existing access roads	KEMA 13.2	X (determined to be longer term project)		
12	Develop and fund an access road program	KEMA 13.2		X	
13	Coordinate access road and veg mgt programs	KEMA 13.2		X	
14	**Evaluate hardening opportunities for both transmission and distribution.**	KEMA 13.3			X
15	**Conduct a system hardening study to determine:**	KEMA 13.3			X
16	Additional opportunities for UG	KEMA 13.3			X
17	Use of different towers in hard hit areas	KEMA 13.3			X
18	Review materials and design standards to match weather	KEMA 13.3			X
19	Locate transmission lines underground	Customer Focus Groups			X
20	Increase tree-trimming	Customer Focus Groups			X

EXHIBIT C

List of Damage Assessors

Potelco Damage Assessors for 2008/09 Storm Season

1	[redacted]
2	[redacted]
3	[redacted]
4	[redacted]
5	[redacted]
6	[redacted]
7	[redacted]
8	[redacted]
9	[redacted]
10	[redacted]
11	[redacted]
12	[redacted]
13	[redacted]
14	[redacted]
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38	[redacted]
39	[redacted]
40	[redacted]
41	[redacted]
42	[redacted]
43	[redacted]
44	[redacted]

Puget Sound Energy Employees with Damage Assessment assignments (Primary and Secondary)

Last Name	First Name	CG Title	Primary ER Assign	Primary ER Location	Secondary ER Assign	Secondary ER Location
			Substation Technical Support - Lead	EST-05E	Damage Assessor	SKC-SVC
			Storm Board Coordinator	KSP-SVC	Damage Assessor	KSP-SVC
			Storm Board Analyst	SKC-SVC	Damage Assessor	SKC-SVC
			Storm Board Analyst	NOK-SVC	Damage Assessor	
			Storm Board Analyst	NOK-SVC	Damage Assessor	NOK-SVC
			Storm Board Analyst	SKC-SVC	Damage Assessor	SKC-SVC
			Storm Board Analyst	KSP-SVC	Damage Assessor	KSP-SVC
			Materials Management	SHU-WHS	Damage Assessor	SKC-SVC
			Flagger	SKC-SVC	Damage Assessor	SKC-SVC
			Flagger	SKC-SVC	Damage Assessor	SKC-SVC
			Flagger	SKC-SVC	Damage Assessor	SKC-SVC
			ESO System Ops	ESO-EOC	Damage Assessor	
			EOC Resouce Coordinator	ESO-EOC	Damage Assessor	SKC-SVC
			EOC Resouce Coordinator	ESO-EOC	Damage Assessor	SKC-SVC
			EOC EMS Specialist	ESO-EOC	Damage Assessor	NOK-SVC
			EOC EMS Specialist	ESO-EOC	Damage Assessor	NOK-SVC
			EOC Director	ESO-EOC	Damage Assessor	SKC-SVC
			EOC Data Specialist	ESO-EOC	Damage Assessor	NOK-SVC
			Environmental Spills	KSP-SVC	Damage Assessor	KSP-SVC
			Environmental Spills	SKC-SVC	Damage Assessor	NOK-SVC
			EFR Supervisor	NOK-SVC	Damage Assessor	
			Driver		Damage Assessor	
			Driver		Damage Assessor	
			Driver	KSP-SVC	Damage Assessor	KSP-SVC
			Driver	WHA-SVC	Damage Assessor	SKA-SVC
			Driver	WHA-SVC	Damage Assessor	SKA-SVC
			Driver	NOK-SVC	Damage Assessor	NOK-SVC
			Driver	SKA-SVC	Damage Assessor	WHA-SVC
			Driver	SKA-SVC	Damage Assessor	WHA-SVC
			Driver	SKA-SVC	Damage Assessor	WHA-SVC
			Driver	KSP-SVC	Damage Assessor	KSP-SVC
			Driver	WHA-SVC	Damage Assessor	SKA-SVC
			DDD Specialist	NOK-SVC	Damage Assessor	NOK-SVC
			Damage Assessor	SKC-SVC	Medic/Flagger	NOK-SVC
			Damage Assessor	NOK-SVC	Medic/Flagger	NOK-SVC
			Damage Assessor	OLY-SVC	Lodging Coordinator	SKC-SVC
			Damage Assessor	PUY-SVC	Flagger	PUY-SVC
			Damage Assessor	SKC-SVC	Flagger	PUY-SVC

Last Name	First Name	CC Title	Primary ER Assign	Primary ER Location	Secondary ER Assign	Secondary ER Location
			Damage Assessor	NOK-SVC	Flagger	PUY-SVC
			Damage Assessor	NOK-SVC	EOC EMS Specialist	ESO-EOC
			Damage Assessor	PUY-SVC	Driver	PUY-SVC
			Damage Assessor	KSP-SVC	Driver	KSP-SVC
			Damage Assessor	KSP-SVC	Driver	KSP-SVC
			Damage Assessor	NOK-SVC	Driver	NOK-SVC
			Damage Assessor	SKC-SVC	Driver	SKC-SVC
			Damage Assessor	PUY-SVC	Driver	SKC-SVC
			Damage Assessor	NOK-SVC	Driver	NOK-SVC
			Damage Assessor	PUY-SVC	Driver	SKC-SVC
			Damage Assessor	NOK-SVC	Driver	NOK-SVC
			Damage Assessor	SKA-SVC	Damage Assessor	WHA-SVC
			Damage Assessor	NOK-SVC	Damage Assessor	SKA-SVC
			Damage Assessor	NOK-SVC	Damage Assessor	SKC-SVC
			Damage Assessor	SKC-SVC	Damage Assessor	NOK-SVC
			Damage Assessor	SKA-SVC	Damage Assessor	WHB-SVC
			Damage Assessor	WHA-SVC	Damage Assessor	SKA-SVC
			Damage Assessor	PUY-SVC	Damage Assessor	SKC-SVC
			Damage Assessor	KSP-SVC	Coordinator	KSP-SVC
			Damage Assessor	NOK-SVC	Crew Coordinator	NOK-SVC
			Damage Assessor	SKC-SVC	Crew Coordinator	SKC-SVC
			Damage Assessor	SKA-SVC	Crew Coordinator	SKA-SVC
			Damage Assessor	NOK-SVC	Crew Coordinator	NOK-SVC
			Damage Assessor	PUY-SVC	Crew Coordinator	PUY-SVC
			Damage Assessor	NOK-SVC	Crew Coordinator	NOK-SVC
			Damage Assessor	NOK-SVC	Crew Coordinator	
			Damage Assessor	SKC-SVC	Crew Coordinator	
			Damage Assessor	SKC-SVC	Crew Coordinator	
			Damage Assessor	NOK-SVC	Crew Coordinator	NOK-SVC
			Damage Assessor	PUY-SVC	Crew Coordinator	PUY-SVC
			Damage Assessor	SKC-SVC	Crew Coordinator	SKC-SVC
			Damage Assessor	PUY-SVC	Crew Coordinator	PUY-SVC
			Damage Assessor	SKC-SVC	Crew Coordinator	SKC-SVC
			Damage Assessor	NOK-SVC	Crew Coordinator	NOK-SVC
			Damage Assessor	PUY-SVC	Crew Coordinator	PUY-SVC
			Damage Assessor	PUY-SVC	Crew Coordinator	PUY-SVC
			Damage Assessor	WHB-SVC	Crew Coordinator	SKA-SVC
			Damage Assessor	SKC-SVC	Crew Coordinator	SKC-SVC
			Damage Assessor	SKA-SVC	Crew Coordinator	WHB-SVC
			Damage Assessor	NOK-SVC	Crew Coordinator	NOK-SVC

Last Name	First Name	CC Title	Primary ER Assign	Primary ER Location	Secondary ER Assign	Secondary ER Location
			Damage Assessor	NOK-SVC	Crew Coordinator	NOK-SVC
			Damage Assessor	SKC-SVC	Crew Coordinator	SKC-SVC
			Damage Assessor	OLY-SVC	Crew Coordinator	OLY-SVC
			Damage Assessor	SKC-SVC	Crew Coordinator	SKC-SVC
			Damage Assessor	NOK-SVC	Crew Coordinator	NOK-SVC
			Damage Assessor	SKC-SVC	Crew Coordinator	SKC-SVC
			Damage Assessor	NOK-SVC	Crew Coordinator	NOK-SVC
			Damage Assessor	SKC-SVC	Crew Coordinator	SKC-SVC
			Damage Assessor	OLY-SVC	Crew Coordinator	OLY-SVC
			Damage Assessor	NOK-SVC	Crew Coordinator	NOK-SVC
			Damage Assessor	NOK-SVC	Crew Coordinator	NOK-SVC
			Damage Assessor	PUY-SVC	Crew Coordinator	PUY-SVC
			Damage Assessor	SKC-SVC	Crew Coordinator	SKC-SVC
			Damage Assessor	NOK-SVC	Crew Coordinator	NOK-SVC
			Damage Assessor	WHB-SVC	County EOC Liaison	SKA-SVC
			Damage Assessor	KSP-SVC	Back-up Dispatcher	KSP-SVC
			Damage Assessor			
			Damage Assessor			
			Damage Assessor	WHA-SVC		
			Damage Assessor			
			Damage Assessor	NOK-SVC		
			Damage Assessor	PUY-SVC		
			Damage Assessor	SKC-SVC		
			Damage Assessor	SKC-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor	SKC-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor	SKC-SVC		
			Damage Assessor	SKA-SVC		
			Damage Assessor	SKC-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor	WHA-SVC		SKA-SVC
			Damage Assessor	PUY-SVC		
			Damage Assessor			
			Damage Assessor	NOK-SVC		
			Damage Assessor	SKA-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor			

Last Name	First Name	CC Title	Primary ER Assign	Primary ER Location	Secondary ER Assign	Secondary ER Location
			Damage Assessor	PUY-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor	KSP-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor	WHA-SVC		
			Damage Assessor	PUY-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor	SKC-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor	PUY-SVC		
			Damage Assessor	SKC-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor	WHA-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor	NOK-SVC		
			Damage Assessor	SKC-SVC		
			Crew Coordinator	OLY-SVC	Damage Assessor	OLY-SVC
			Crew Coordinator	PUY-SVC	Damage Assessor	PUY-SVC
			Crew Coordinator	WHA-SVC	Damage Assessor	
			Crew Coordinator	SKC-SVC	Damage Assessor	SKC-SVC
			Crew Coordinator	KSP-SVC	Damage Assessor	KSP-SVC
			Crew Coordinator	KSP-SVC	Damage Assessor	KSP-SVC
			Crew Coordinator	SKC-SVC	Damage Assessor	SKC-SVC
			Crew Coordinator	KSP-SVC	Damage Assessor	KSP-SVC
			Crew Coordinator	SKA-SVC	Damage Assessor	SKA-SVC
			Crew Coordinator	SKC-SVC	Damage Assessor	SKC-SVC
			Crew Coordinator	SKC-SVC	Damage Assessor	SKC-SVC
			Crew Coordinator	OLY-SVC	Damage Assessor	OLY-SVC
			Crew Coordinator	PUY-SVC	Damage Assessor	PUY-SVC
			Crew Coordinator	OLY-SVC	Damage Assessor	OLY-SVC
			Crew Coordinator	WHB-SVC	Damage Assessor	WHB-SVC
			Crew Coordinator	SKC-SVC	Damage Assessor	SKC-SVC
			Crew Coordinator	KSP-SVC	Damage Assessor	KSP-SVC
			Crew Coordinator	NOK-SVC	Damage Assessor	NOK-SVC
			Crew Coordinator	SKC-SVC	Damage Assessor	SKC-SVC
			Crew Coordinator	OLY-SVC	Damage Assessor	OLY-SVC

Last Name	First Name	CC Title	Primary ER Assign	Primary ER Location	Secondary ER Assign	Secondary ER Location
			Crew Coordinator	WHB-SVC	Damage Assessor	SKA-SVC
			Crew Coordinator	SKC-SVC	Damage Assessor	SKC-SVC
			Crew Coordinator	WHA-SVC	Damage Assessor	SKA-SVC
			Crew Coordinator	KSP-SVC	Damage Assessor	KSP-SVC
			Crew Coordinator	WHA-SVC	Damage Assessor	SKA-SVC
			Crew Coordinator	KSP-SVC	Damage Assessor	KSP-SVC
			Crew Coordinator	SKC-SVC	Damage Assessor	SKC-SVC
			Crew Coordinator	SKA-SVC	Damage Assessor	SKA-SVC
			Crew Coordinator	SKC-SVC	Damage Assessor	SKC-SVC
			Crew Coordinator	SKC-SVC	Damage Assessor	SKC-SVC
			Crew Coordinator	PUY-SVC	Damage Assessor	PUY-SVC
			Crew Coordinator	OLY-SVC	Damage Assessor	OLY-SVC
			Crew Coordinator	WHA-SVC	Damage Assessor	SKA-SVC
			Crew Coordinator	KSP-SVC	Damage Assessor	KSP-SVC
			Crew Coordinator	OLY-SVC	Damage Assessor	OLY-SVC
			Crew Coordinator	NOK-SVC	Damage Assessor	NOK-SVC
			Crew Coordinator	WHA-SVC	Damage Assessor	WHA-SVC
			Crew Coordinator	WHA-SVC	Damage Assessor	SKA-SVC
			Crew Coordinator	SKA-SVC	Damage Assessor	WHA-SVC
			Crew Coordinator	PUY-SVC	Damage Assessor	PUY-SVC
			Crew Coordinator	NOK-SVC	Damage Assessor	NOK-SVC
			Crew Coordinator	PUY-SVC	Damage Assessor	PUY-SVC
			Crew Coordinator	KSP-SVC	Damage Assessor	KSP-SVC
			Crew Coordinator	PUY-SVC	Damage Assessor	PUY-SVC
			Crew Coordinator	NOK-SVC	Damage Assessor	NOK-SVC
			Crew Coordinator		Damage Assessor	WHA-SVC
			Crew Coordinator	SKC-SVC	Damage Assessor	SKC-SVC
			Crew Coordinator	WHB-SVC	Damage Assessor	SKA-SVC
			Crew Coordinator	SKA-SVC	Damage Assessor	WHB-SVC
			Crew Coordinator	SKC-SVC	Damage Assessor	SKC-SVC
			Crew Coordinator	SKC-SVC	Damage Assessor	NOK-SVC
			Crew Coordinator	SKA-SVC	Damage Assessor	WHA-SVC
			Crew Coordinator	SKC-SVC	Damage Assessor	SKC-SVC
			Crew Coordinator	OLY-SVC	Damage Assessor	OLY-SVC
			Crew Coordinator	WHA-SVC	Damage Assessor	SKA-SVC
			911 Call Coordinator	SKC-SVC	Damage Assessor	SKC-SVC
					Damage Assessor	
					Damage Assessor	
					Damage Assessor	
					Damage Assessor	

Last Name	First Name	CC Title	Primary ER Assign	Primary ER Location	Secondary ER Assign	Secondary ER Location
[redacted]					Damage Assessor	OLY-SVC
					Damage Assessor	
					Damage Assessor	WHA-SVC
					Damage Assessor	

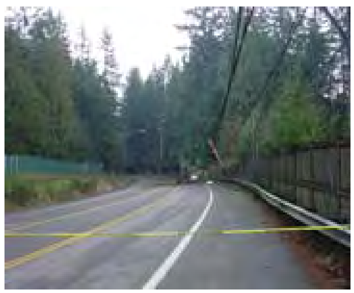
EXHIBIT D

Damage Assessment Training Guide

DAMAGE ASSESSOR GUIDE

2008





PSE PUGET SOUND ENERGY

The Energy To Do Great Things

Puget Sound Energy
Operations – Emergency Planning
P.O. Box 90868 EST-05E
Bellevue, WA 98009-0868
425-454-6363

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Purpose of This Book

This manual is a reference book for Puget Sound Energy (PSE) & Quanta Contract Crew Coordinators, and is part of PSE's Emergency Response Plan.

During a storm or other emergency, it can be difficult to remember all of Puget Sound Energy's policies and procedures when working as a Damage Assessor. This book contains information and tips to help you in your role as a PSE Damage Assessor, as part of PSE's Emergency Response Plan. This book is designed to be used in conjunction with the Damage Assessment Form (2050).

Comments

Direct any suggestions, additions, or corrections to Operations & Emergency Planning, ext. 81-3962.

How to Order

To order additional copies, contact Operations & Emergency Planning, ext. 81-3962.

Notes:

Introduction

Background

PSE's electric system can be damaged by windstorms, ice and snow storms, earthquakes, floods, and events such as car-pole accidents. Any time there is damage to PSE's system, it needs to be assessed prior to dispatching a line crew for repairs.

PSE's Electric First Responders (Service Linemen) generally handle damage assessment for minor wind events, car-pole accidents, and other "single" type events.

However, for medium to large storms and other major events, Damage Assessment teams are deployed to perform an initial assessment and communicate their findings back to the appropriate storm management center (storm board).

You As a Damage Assessor

While you are acting as a Damage Assessor, it is important to keep in mind that you may move on into a Contract Crew Coordinator role, and as such, you may end up working in areas that you've damage assessed. As a Contract Crew Coordinator, you will want to take your crew to a job with all the materials and equipment needed. You will appreciate a job well done by the Damage Assessor.

Therefore, it is suggested that you go about your duties as a Damage Assessor as if you will be returning to the area with a contract crew.

What You Can Expect

When called out for Damage Assessment duty, you may be away from home for long periods of time, even several days. There are a few things you should consider before storm season.

- Have a discussion with family members regarding your storm duty and possible impacts on them.
- Provide family members with contact information, including your cell number and the operating base phone number.
- Should the neighbors be notified that you will be away for awhile?
- Do arrangements need to be made for child care?
- You may need to purchase meals while away, so plan to bring some money and/or a credit card.
- Don't forget prescription or other medications and an extra pair of eyeglasses.

Continued on next page

What You Can Expect, *Continued*

Personal Preparedness Bag

During a storm, you may be on duty for an extended time. It's a good idea to plan ahead and make up your own personal preparedness storm duty bag. Below are some suggestions of items to include in your bag.

Clothing Supplies	Work Gear	Nice to Have
Extra coat	Hard hat and liner	Thermos
Extra shirt	Leather gloves/glove liners	Cooler
Extra jeans	Disposable gloves	Handwarmers
Extra underwear	Safety glasses	Snacks/Beverages
Extra socks	Ear plugs	Money and credit card
Warm hat (knit or wool)	Rain gear	
Gloves	Waterproof footwear	
Insulated underwear	Safety Vest	
Towel(s)	Toiletries and medications	

Figure 1 Example of a Personal Preparedness Bag

Reporting For Duty

Required Equipment

When you are called to damage assessment duty, you will most likely be directed to a local operating base. You may also be directed to an Area Coordinator in a more remote location. In either case, you must report with the following:

- Hard Hat
- Reflective Safety Vest
- Safety Glasses
- Sturdy Shoes
- Cell phone with charger

Optional Equipment

Additionally, the following items can make your job easier:

- Rain gear, warm jacket, gloves, hat
- Binoculars
- Hearing protection
- GPS Device

Equipment/ Materials Provided by Operating Base

The operating base will provide the Damage Assessor with a pre-packaged "storm kit" containing the following:

▪ 3 cell flashlight	▪ 50 pack - Caution: Abnormal Condition tags	▪ Spiral note pad
▪ 6 pack of D cell batteries	▪ 50 pack – Danger: Do Not Operate tags	▪ Clipboard
▪ Battery operated strobe light	▪ 50 pack – Storm Damage tags	▪ 12 pack of 3″ sticky note pads
▪ Portable Spot Light	▪ Pad of oil spill forms	▪ Ball point pens
▪ Roll of caution tape	▪ Pad of pole/transformer replacement forms	▪ Permanent Marker
▪ 3-way 12 V outlet	▪ Pad of self protection clearance forms	

Additionally, the operating base will provide you with:

- Local circuit maps
- Local area maps
- Contact phone numbers

Key Information

Make sure you find out and keep the following key information with you.

- Operating base telephone numbers.
- Damage Assessment Coordinator's telephone number.
- Warehouse telephone number.
- Electric Dispatch phone number.
- Local radio communications channel (if you have a company radio).

Communication

The primary method of communication while damage assessing is by cell phone. Always take your cell phone with you when called to duty as a damage assessor. Be sure to bring both wall outlet and vehicle chargers to keep your cell phone battery charged in the event you are working away from home for an extended period.

If you are damage assessing out of cell phone range, you may either drive to within cell phone range, or drive back to the operating base to hand deliver the damage assessment reports. The operating base supervisor will work with you to decide which method is best.

Some PSE and Quanta vehicles are equipped with two-way radios. Use this method only to communicate if assistance is needed or you are reporting an emergency. Otherwise, the airwaves need to be kept clear for switching communication.

Emergencies

Always know the address, city, and county where you are assessing. In an emergency or injury situation this information is critical.

If an emergency arises, use your cell phone to call for help whenever possible. If you have a company radio, you can use it to alert others in the area who could lend assistance. See PSE Standard 0100.0990, "Radio Operating and Help Procedures for PSE Electric Operations," which contains procedures for emergency radio use.

Call the operating base as well to let them know of the situation.

For additional information on calling for help, see "Responding to Medical Emergencies" in the *Safety* tab.

Checking In

When reporting to the operating base, it is important to sign in first and introduce yourself to the Damage Assessment Coordinator, who will assign you a work area and provide any pertinent information.

Patrolling

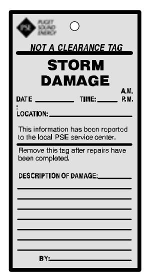
The operating base will deploy damage assessment teams to various areas. A team may assigned to patrol one or more circuits, and at times several teams may be used in one general area.

Patrolling may either be the entire line, from the substation to the end, or just a specific section of line. In either case, make sure you patrol the whole line that you are assessing. There can be multiple cases of damage on a given section of line. Some laterals run for several miles.

Storm Damage Tags

These bright pink tags are designed to alert other assessors that a damage assessment has been completed. When you have completed assessing an area and reported your findings to the storm base, fill out a Storm Damage tag and nail or otherwise attach it to a pole near the beginning of the assessed area.

Figure 1 Storm Damage Tag



MID 9996116

The Damage Assessment Form

A Damage Assessment (D/A) Form (2050) must be filled out for each case of damage.

For simple, easy-to-assess cases, such as a single-phase lateral with just a few spans, all the damage and required material may be recorded on one form.

However, in most cases, a separate D/A form will be required for each pole. This includes:

1. Poles with equipment (reclosers, sectionalizers, transformers, etc.).
2. Corner poles.
3. Poles with lateral taps.
4. Transmission poles with distribution underbuild.
5. Poles with underground terminations, etc.

Figure 2 Damage Assessment Form, Page 1

PSE PUGET SOUND ENERGY
The Energy To Do Great Things

DAMAGE ASSESSMENT

USE REVERSE FOR NOTES.

Use back if needed.

ASSESSOR'S NAME	DATE	INCIDENT NO.	SITE NO.
CELL NO.	TIME	☐ SERVICEMEN JOB ☐ TREE CREW JOB ☐ LINE CREW JOB	
CIRCUIT OR T-LINE NAME	OH CIRCUIT MAP	GRID/STRUCTURE NO.	

DANGER TO PUBLIC? ☐ YES ☐ NO **OIL SPILL PRESENT?** ☐ YES ☐ NO **TRANSITE RISER PIPE?** ☐ YES ☐ NO

DESCRIBE: **IF "YES" REPORT IMMEDIATELY TO SERVICE CENTER**

ADDRESS SITE (DETAIL DESCRIPTION)

IS THE SITE ACCESS RESTRICTED? ☐ YES ☐ FLOOD ☐ SLIDE ☐ WASHOUT ☐ DOWNED TREES ☐ WALK-IN JOB

ARE FLAGGERS REQUIRED? ☐ YES ☐ NO ____ QUANTITY DAY JOB ONLY? ☐ YES

☐ TREES IN LINE ☐ BRANCHES ACROSS PHASES ☐ WIRE DOWN ☐ OTHER (DESCRIBE)

☐ BROKEN POLE/ARM ☐ SERVICE DOWN ☐ OPEN CUTOUT

WHAT KIND OF POLE? *(CHECK ALL EQUIPMENT AT SITE)*

VOLTAGE	TRANSMISSION STRUCTURE		DISTRIBUTION STRUCTURE	
☐ SEC/SVC	☐ HPA	☐ DISTRIBUTION UNDERBUILD	☐ POLE TOP PIN 1PH	☐ LATERAL
☐ 4KV	☐ HPD	☐ VERTICAL TURN	☐ POLE TOP PIN 3PH	☐ FIBERGLASS ARM 3PH
☐ 12KV	☐ 2-POLE "H" FRAME	☐ VERTICAL DEADEND	☐ DEADEND	☐ WINGARM
☐ 34KV	☐ 3-POLE "H" FRAME	☐ WISHBONE	☐ CORNER 3PH	☐ DOUBLE CIRCUIT
☐ 115KV			☐ PRIMARY NEUTRAL 3PH	
☐ 230KV			☐ OTHER (DESCRIBE):	

WHAT IS BROKEN? *(FILL IN ALL AVAILABLE INFORMATION)* ☐ STREET LIGHT ON POLE? INTO-LIGHT TAG NO. ____ ☐ CELL NET EQUIPMENT? CELL NET UNIT NO. ____

POLES SIZE/CLASS/QUANTITY		ARMS SIZE/CLASS/QUANTITY	BRACES	BOLTS
STEEL PIN	POLE TOP PIN	INSULATORS	DEADENDS	RIGID CLEVIS
DOWN GUY	SPAN GUY	GUY GUARDS	STRAIN INSULATOR	GUY HOOK

TRANSFORMER ________ KVA ☐ 1PH ☐ 3PH ☐ 120/208 ☐ 120/240 ☐ 277/480 ☐ BUSHINGS ____ ☐ BANKED 2 OR 3

TRANSFORMER CO. ID NO. ☐ PADMOUNT

CONDUCTOR SIZE | TYPE ☐ TREE WIRE ☐ COPPER ☐ ACSR / AAC ☐ TRIPLEX | LENGTH | SEC / SVC SIZE & LENGTH

SPLICES ____#4CU ____#6CU ____#4ACSR ____#2ACSR ____#4/O ACSR ____#336 ACSR ____#397 AAC

SWITCH NO. ________ ☐ LINK BREAK ☐ LOAD INTERRUPTER ☐ SOLID BLADE ☐ GANG-OPERATED

TERMINATION ☐ 1PH ☐ 3PH *(INSERT QUANTITY)* ☐ 750____ ☐ 1/O____

RISER *(IF TRANSITE, REPORT IMMEDIATELY TO SERVICE CENTER)* NOTE QUANTITY FOR EACH SIZE/TYPE

DB120 ____ 2" ____ 3" ____ 4" ____ 6"

SCH 80 ____ 2" ____ 3" ____ 4" ____ 6"

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Continued on next page

Figure 3 Damage Assessment Form, Page 2

PUGET SOUND ENERGY
The Energy To Do Great Things

DAMAGE ASSESSMENT

2050 08/07

PAGE 2 OF 2

Filling Out the D/A Form

When assessing damage, you are collecting information to be communicated back to the operating base. Fill out the D/A form as completely as possible. Not all fields will require an entry, but remember, the more completely you fill out the form, the easier it will be for the Contract Crew Coordinator and responding line crew to arrive with the proper materials, equipment, and personnel.

The D/A form is fairly self-explanatory, but here are a few hints to help you properly fill out the form.

Block Title	Information
Incident No.	Can be used to record the Incident Number, if one has been assigned by System Operations. This is helpful for the operating base folks.
Site No.	May be used by you as a Damage Assessor to help relate the form to a particular area on a map, by creating your own unique numbering system, noting this on the D/A Form, and also on a copy of a circuit map. This method can help the operating base in their crew assignments.
Type of Job	Used to denote the type of crew to be deployed: A **Serviceman Job** is typically only service and secondary work. A **Tree Crew Job** is used when a tree crew is required to either accompany the line crew or to clear an area for a line crew to have accessibility. A **Line Crew Job** is for most work, when a line crew is required to restore damaged transmission and distribution lines.
Circuit or T-Line Name	Very important information that needs to be included for each location.
Address Site	Include the street address and a reference to an existing switch number, if available. This helps the crew find the location on a circuit map. Note any accessibility issues and provide driving directions for the crew.

On the rest of the form, check applicable boxes and fill in quantities. Use the reverse of the form when more space is needed, or to help explain different circumstances.

Important Considerations for the D/A Form

The following fields are of critical importance:

- **Oil Spill:** Is there an oil spill? If so, this needs to be reported to the storm base immediately
- **Address:** Look for an address on a mailbox; the nearest intersection; some type of notable landmark; a pole, switch, or grid number; or a description of the location (e.g., 6 spans east of ______)
- **Access:** Any unusual access obstacles, including washed out roads, trees down across the road, or walk-in locations.
- **Flaggers:** Will flaggers be needed to control traffic once a crew arrives on site?
- **Transite Pipe (primary and secondary risers):** Notify the operating base early so environmental clean up can be arranged.

Making a Material List

Typically, storeroom personnel at the local operating base will be knowledgeable enough to read material lists on D/A forms and issue the correct items for a particular application (e.g., a single phase tangent pole with pole-top pin).

However, during especially large events, there might not be enough “seasoned” storeroom people to fully staff the warehouse, necessitating the use of personnel that are not familiar enough with “construction units” and so forth, to be able to issue the correct material.

For these larger events, the Damage Assessor may be asked to include Material Identification Numbers (MIDs) with the lists of material that are submitted. It may be useful for a Damage Assessor to take a copy of the Electric and Gas Materials Catalog (MatCat) along on damage assessment duty. This Damage Assessment Guide includes examples of some of the more common applications, including MIDs.

NOTE: Unless specifically asked, do not include MIDs when filling out D/A forms.

How to Report Damage

There are two ways to report damage after assessing an area:

- You may be asked to call the damage in to the operating base; or,
- You may be asked to deliver your completed damage reports to the operating base.

Make sure you understand what is expected at your location.

If/when you call in a damage assessment report, give your name and location, and the damage you’ve noted on your D/A form. The operating base will have someone taking damage assessment reports. That person may ask additional questions, so it is best if you can report the damage from the actual site before moving on to another site.

If communications are poor or out, you may need to hand-deliver assessment information to the operating base.

The Damage Assessment Team

Partner Up

Make sure you are assigned a driver. Drivers may or may not have damage assessment experience, so spend a few minutes discussing the assignment and your expectations of the driver. As Damage Assessor, you will be focused on looking for damage. The driver's first responsibility is to watch the road.

Driver's Duties and Responsibilities

When working on a Damage Assessment Team, the driver shall:

- Follow Damage Assessor's instructions – the Damage Assessor is the Team Leader.
- Make sure the vehicle is functional.
- Maintain an appropriate speed and obey speed limits.
- Watch out for other traffic and road hazards.
- Watch fuel gauge as fuel may not be easy to obtain in some areas.
- Keep track of extra equipment and supplies (flashlights, flares, etc.).
- Stay with the vehicle unless the Damage Assessor specifies otherwise.

General Safety

When assessing damage, your number one objective is to protect yourself.

- Stay clear of downed equipment.
- Use caution when coming across downed poles and wire. Poles and trees may appear down, but can still move unexpectedly.
- Lines lying on the ground may still be energized or can become reenergized.
- Trees may be leaning into overhead conductors which may break under strain and fall down, resulting in injury.
- Stay in your vehicle whenever possible.

Electrical

Many PSE employees with engineering, planning, or management backgrounds may be assigned duties as a Damage Assessor. Some of these employees are not qualified electrical workers under the requirements of WAC 296-45, and may not perform electrical work. Safety requirements for non-electrical workers, covered under WAC 296-155 and WAC 296-800-280, include:

- Do not violate the ten foot rule (WAC 296-155) for approaching exposed conductors.
- Do not touch covered or insulated conductors such as tree wire or underground cables.
- Learn to recognize the electrical equipment you could encounter in the field, and know the associated hazards.
- Know what to do in the event of an electrical contact. ***Any employee, regardless of classification, who has an electrical contact shall immediately seek emergency medical treatment***.

In the Field

Keep in mind the following safety items when working in the field:

- Always wear your hard hat.
- Reflective vests must be worn when working in or near the roadway.
- Your vehicle is not an emergency vehicle. Obey all traffic laws.
- Be aware of falling trees, limbs, and debris.
- Be aware of traffic. Cones cannot stop cars.
- Do not contact lift equipment or line trucks.
- Wear your safety glasses.
- Use vehicle flashers and/or strobe light when on shoulder.

Downed Lines

Stay away from all downed lines. Let the journeymen on the crew handle any downed lines, whether or not they are power lines. NEVER attempt to move a downed line yourself. Report it to the local service center.

Keep the public away from downed lines. Use cones and caution tape as a barricade

Do not assume lines with black insulation on them are phone or cable TV. The tree wire PSE uses for primary voltages in many areas can look just like communication lines.

Lines identified as TV or phone could be tangled up with electric conductor farther away and could become energized.

Witnessing Unsafe Actions

Unsafe Actions by the General Public

If you observe the public acting or working in an unsafe manner around downed lines, warn them of the danger and ask them to stop their unsafe activity. WAC safety rules do not apply to the general public, so the Department of Labor and Industries cannot require the public's compliance.

If the situation is endangering the crew, call 911.

Unsafe Actions by Line Crews and/or Contractors

If you observe line crews or other contractors (flaggers, etc.) working in an unsafe manner, contact the operating base.

Responding to Medical Emergencies

Medical Emergency Procedures

Step	Action
1	From a safe location, dial area emergency number (911).
2	State that you are in need of medical aid and be ready to report the following information: ▪ "This is Puget Sound Energy" or "This is Potelco/Quanta." ▪ "I am at (give exact address)." ▪ Type of problem or injury. ▪ Individual's present condition and age. ▪ Sequence of events leading to the emergency. ▪ Medical history, medication if known.
3	Avoid moving the injured or ill person.
4	Until medical personnel arrive, render first aid/CPR within training and qualification limits without endangering the victim or others.
5	Contact Eastside System Supervisor at 81-4681 or (800) 383-1759 or (425) 882-4681 or radio through dispatcher.
6	Immediately notify the employee's supervisor of the emergency.

Providing Emergency Aid

If available, trained and certified PSE/Quanta first aid providers may provide emergency first aid and life support until relieved by aid crews. Whenever an aid car is called, the employee can be transported as recommended by aid personnel to the appropriate emergency medical facility for further treatment.

Providing Non-Emergency Aid

In circumstances requiring non-emergency care, PSE and/or Quanta personnel trained in first aid may render appropriate care. Should the injured employee require further medical treatment and assistance is warranted, you may drive the employee to the nearest emergency medical facility or, if they prefer, to the employee's medical provider.

⚠ NOTICE!

Notify the operating base of any events where emergency or non-emergency aid has been administered.

Responding to Critical Incidents

A critical incident is defined as:

- Any serious employee injury (an injury that results in hospitalization or a fatality); or
- Any workplace violence or threat; or
- Any natural disaster that significantly impacts PSE, Quanta employees or contractors' establishments.

Critical Incident Procedure

Any PSE or Quanta employee who becomes aware that a critical incident has occurred shall do the following in accordance with their training.

Step	Action
1	Attend to injured people as appropriate/needed (e.g. calls 911, provides first aid/CPR as trained). Ensure injured employees are transported properly and note the hospital that they are transported to.
2	Secure incident site to the greatest extent possible as appropriate/needed.
3	Initiate and/or facilitate evacuation as trained to ensure life safety.
4	Contact the Eastside System Supervisor, 81-4681 or (800) 383-1759 or (425) 882-4681 or radio dispatcher. ***NOTE:*** System Supervisor will notify appropriate company personnel including department management.
5	Contact the operating base.
6	Eastside System Supervisor immediately contacts: ▪ Managers of each affected department (including Quanta Management) ▪ PSE Human Resources ▪ PSE Safety and Operations Training ▪ In the event of any workplace violence or threat, calls PSE Security 24–hour Cell Phones: (425) 766–9595 or (425) 766-9430.

Notes:

Power Poles

Poles are categorized by length and class.

- Guy stub poles and service poles are 30′ – 35′ tall.
- Distribution poles are in the 40′ – 45′ range. Occasionally they are a little taller when there are clearance issues.
- Transmission poles are in the 65′ – 85′ range, though some are taller (see the *Transmission System* tab for detailed information on transmission poles).

Pole class is determined by the diameter of the pole. The length and class can be found on the pole identification tag affixed to the pole gain. Note this information if it is safe to approach the downed pole and the pole identification tag is readily accessible.

If the downed pole is in an unsafe location, or it is broken too badly to determine its length and class, look to the pole on either side of the downed pole. They are likely the same size.

Figure 1 Typical Pole Tag in Pole Gain

Distribution Crossarms

NOTE: For transmission crossarms, see the *Transmission System* tab in this book.

Wooden Crossarms

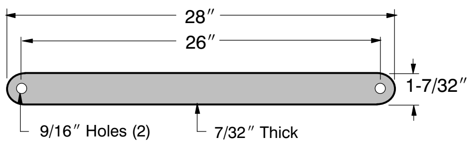
These crossarms come in various lengths. The most common are 9′ and 11′, though 13′ arms are used for double circuits.

If a damaged wood crossarm is still in the air, it is difficult to tell the length of the arm from the ground. Look at the cross arm braces.

- If there are two flat braces (per arm), the arm is 9′ in length.
- If there is a one-piece angled V-shaped brace, the arm is 13′ (MID 8761700).

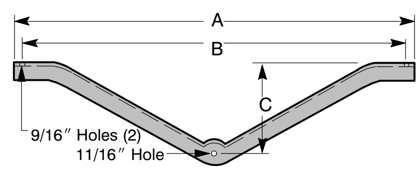
Although 11′ arms can use either type of brace, they usually use an 11′ V brace (MID 8761600).

Figure 2 Flat Crossarm Brace



MID 8763700

Figure 3 Typical Double Span Angle Iron Crossarm Brace



Dimensions

A	B	C	Steel Angle Size	Material ID
63″	60″	18″	1-1/2″ x 1-1/2″ x 3/16″	8761600
75″	72″	22″	1-3/4″ x 1-3/4″ x 3/16″	8761700

In general:

- 1 phase primary neutral = 9′ arm
- 3 phase, common neutral = 9′ arm
- 3 phase, primary neutral = 11′ arm
- 3 phase wing arm = 11′ arm (uses a different type of brace)
- 3 phase double circuit = 13′ arm

Figure 4 Double Circuit

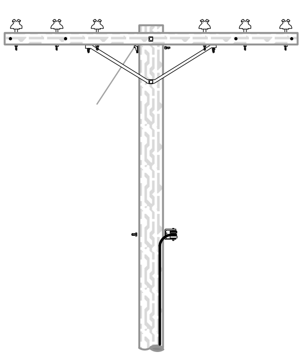


Figure 5 Single-Phase, Primary Neutral

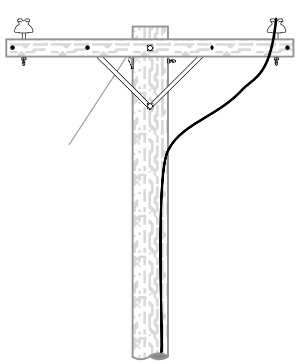


Figure 6 Three-Phase, Pole Top Pin

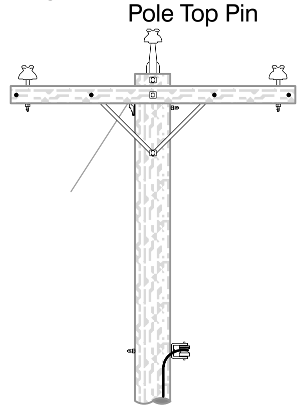
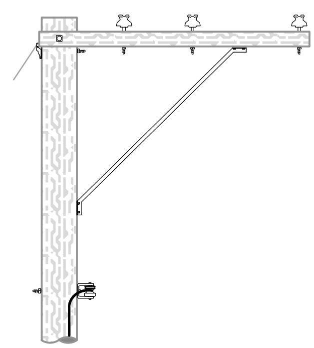


Figure 7 Wingarm

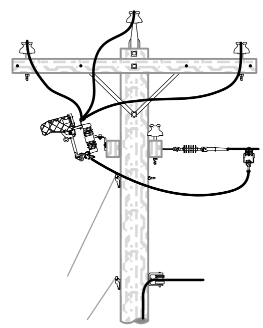


Multiple Crossarms

Often conductors are "double deadended," meaning there are two crossarms back to back. This construction is often used for angle poles, when the lines are not tangent (straight).

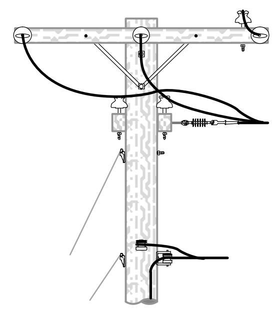
A lower set of double arms is used for a single-phase line tap off of a three-phase line.

Figure 8 Tap



For corner poles, a second set of double arms may be added at approximately 90 degrees to the top arms.

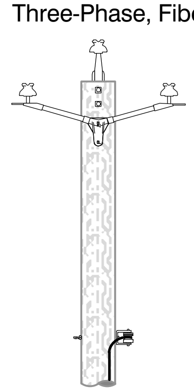
Figure 9 Three-Phase Corner Pole



Fiberglass Crossarms

In some cases where there are right-of-way issues, fiberglass crossarms are used in a "compact construction technique." These fiberglass arms come in single-, double-, triple-, and deadend-arm configurations. They are also used for replacing old steel arms.

Figure 10 Three-Phase, Fiberglass Arm



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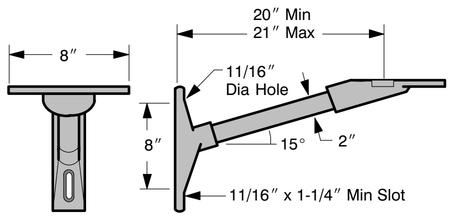
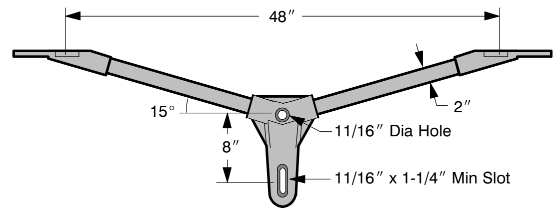
Fiberglass Crossarms, *continued*

Figure 11 Single Bracket Arm



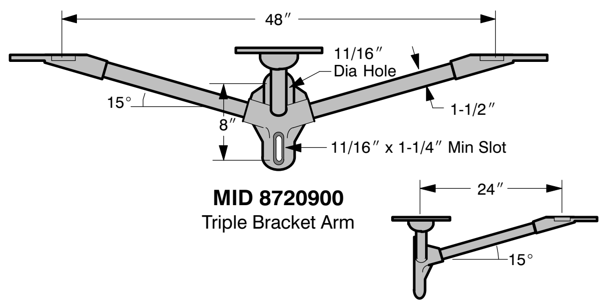
MID 8721100

Figure 12 Double Bracket Arm



MID 8721000

Figure 13 Triple Bracket Arm



MID 8720900
Triple Bracket Arm

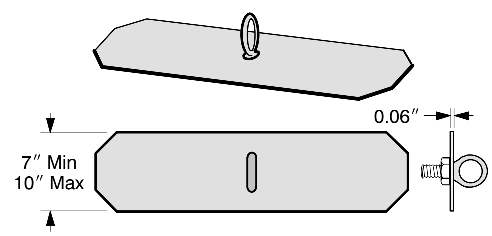
Triple bracket arms are used for three-phase, 1/0 cable termination brackets.

Pole Grounds

Every new pole installed on PSE's system, whether distribution or transmission, is required to have a pole ground installed.

- Distribution poles – run the pole ground up the pole and connect it to the common or primary neutral.
- Transmission poles with distribution underbuild – install as described above for distribution poles.
- Transmission poles without distribution underbuild – cut the ground wire off just below the ground surface so it will be available if an underbuild system is installed in the future.

Figure 14 Ground Plate



MID 8969401

Copper ground plates are attached to a pole butt.

A **Ground Wire Moulding (MID 8920300)** is required to be installed at the base of the pole, covering the first 8 feet of the pole ground wire.

Order plenty of **Ground Wire Molding Staples (MID 9058100)**. PSE is currently applying more staples than usual to discourage wire theft.

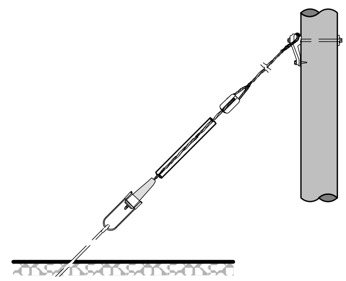
The following is a typical list of material needed for a pole ground.

POLE GROUND

DESCRIPTION	MID	QTY
Ground Plate	8969401	1
Pole Ground Wire	8459000	45′
Moulding	8920300	1
1/2″ Staples	9058100	Bin Stock
1 1/2″ Staples	1391100	Bin Stock

Guy Wires

Figure 15 Example of 3/8″ Down Guy



Description	MID	Qty
3/8 Guy Wire	8585200	40
3/8 Guy Whip	8847700	3
3/8 Auto Grip	8846700	1
Guy Hook	8877400	1
Insulator	9391100	1
Guy Guard	9000500	1

Down Guys

In most cases, when a pole goes over, one or more guy wires break. However, the anchor rarely gets pulled out of the ground and can be reused. Guy wires are stocked in three basic sizes: 3/8″, 7/16″, and 1/2″ diameters. Broken guy wire may be spliced together using an automatic guy wire splice.

Figure 16 Guy Wire Splices

Guy Wire Size	Material ID
5/16″	2224000
3/8″	2224100
7/16″	2224200

Typical
Automatic Splice for Guy Wire

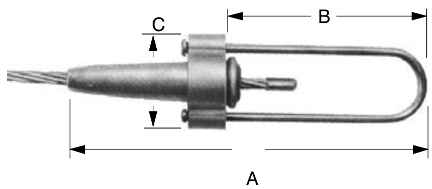
Continued on next page

Down Guys,
continued

However, it is often easier to attach a new guy wire. There may be more than one guy wire attached to a pole. These are sized and placed by an engineer to provide proper support. Make sure you order enough material to replace each guy wire.

When installing new guy wire, an automatic guy grip will be required for each guy wire.

Figure 17 Automatic Guy Grips



Typical
Automatic Guy Grip

Wire Size	Bail Length	Dimensions A	B	C	Material ID
3/8″	Short	10-1/8″	6-7/8″	1-5/8″	8846700
3/8″	Long	17″	12″	1-5/8″	8846800
7/16″	Short	14-3/4″	8″	2-1/4″	8846900
7/16″	Long	22″	15-1/4″	1-15/16″	8847000

This guy grip is used only for attaching guy wire to anchor rods. The grip is supplied with a solid stainless steel bail.

Span Guys

Not all guy wires are down guys. PSE also uses span guys on occasion. These will be stretched between two poles using the same hardware and wire as down guys.

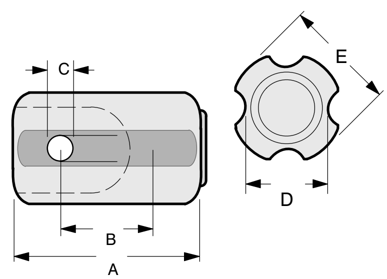
Guying Insulators

Every down or span guy will require one or more insulators, depending on the application.

Strain insulators are used for insulating down and span guys.

Figure 18 Typical Strain Insulator

Dimensions A	B	C	D	E	Material ID
4-1/4″	2-1/4″	7/8″	2-1/8″	2-7/8″	9391100
5-1/2″	3-1/8″	1″	2-3/8″	3-1/8″	9391200



MID 9391100

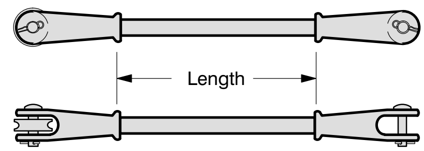
Continued on next page

Guying Insulators, *continued*

Guy strain clevis-clevis insulators are used to insulate guy wires which may inadvertently become energized.

Figure 19 Typical Guy Strain Clevis-Clevis Insulator

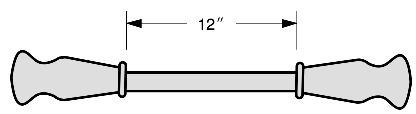
Length	Min Breaking Strength (lbs)	Material ID
12″	30,000	9395900
144″	15,000	9396400
144″	30,000	9396500
96″	15,000	9396600
96″	30,000	9396700



These insulators are used to insulate guy wires which may inadvertently become energized.

Guy strain thimble-thimble insulators are used to insulate guy wires for 34.5 kV distribution.

Figure 20 Typical Guy Strain Thimble-Thimble Insulator

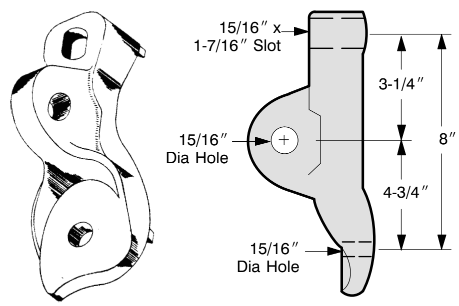


MID 9397000

Guying Pole Hardware

There are a number of different pieces of hardware to attach a guy wire to a pole. Remember to try to replace damaged hardware with like hardware. Listed below is some typical guy pole hardware.

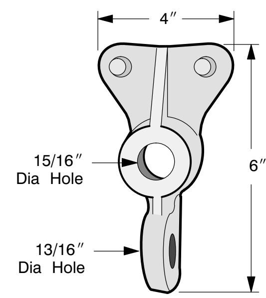
Figure 21 Pole Eye Plate



MID 8969300

Pole eye-plates attach guy wires to poles.

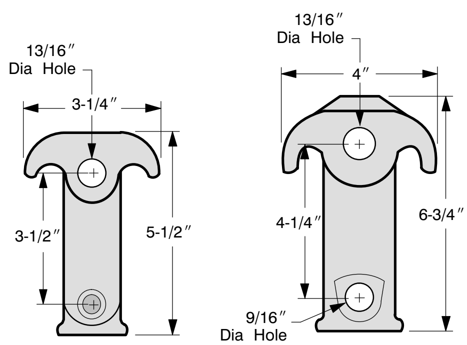
Figure 22 Clevis-Type Guy Plate



MID 8877700

Clevis-type guy plates attach guy wires to poles.

Figure 23 Guy Hooks



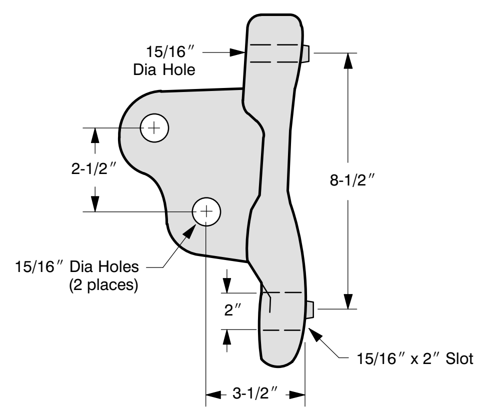
8877400
5/16″ to 3/8″ Guy Hook

8877300
7/16″ to 1/2″ Guy Hook

Guy Wire Size	Material ID
5/16″	8877400
3/8″	8877400
7/16″	8877300
1/2″	8877300

Guy hooks attach guy wires to poles.

Figure 24 Double-Eye Pole Plate



MID 8969000

Double-eye plates typically attach guy wires to transmission deadend structures.

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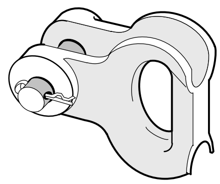
Guying Pole Hardware, *continued*

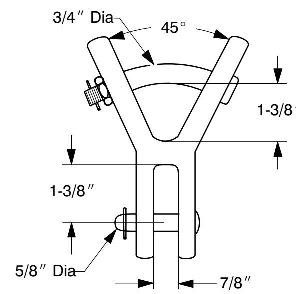
Figure 25 Thimble Clevis



MID 9995638

The thimble clevis is used with chain links and anchor shackles to attach guy wire to pole-eye plates.

Figure 26 Y-Clevis



MID 9997083

The Y-Clevis Clevis is used to attach guy wires to pole eye plates.

Bolts, Screws, and Washers

New bolts, screws, washers, nuts, etc. will be required when framing new poles.

Conductor Sizes and Types

Over the years, PSE has used a variety of copper and ACSR overhead conductors in various sizes. You can expect to encounter several different sizes of wire when damage assessing. PSE does not stock replacement wire for most of the uncommon sizes. Splices, however, are usually available to join two different sizes of wire.

NOTE: For transmission conductor types and sizes, see the *Transmission System* tab in this book.

Distribution Conductor

While it is usually pretty easy to differentiate the type of wire material, determining its size can be a challenge. Overhead primary conductor is manufactured of two types of material: copper wire and aluminum wire.

Copper wire is found in two basic types – bare and covered (insulated). Copper wire ranges in size from #6 to #2 (smaller to larger) single strand, and 2/0 and 4/0 stranded. Bare copper wire that has been installed for quite a while and exposed to the elements will typically turn a greenish color.

Table 1

Copper wire sizes

Size AWG or kcmil	Number of Strands	Material ID
4/0	7	8482200
2/0	7	8482300
2	1	8483500
4	1	8483700

There are two types of **aluminum wire.** The most common is known as ACSR (Aluminum Conductor, Steel Reinforced), which is stranded wire with a steel core. Sizes commonly found on PSE's distribution system include sizes from #2 (smaller) to 2/0, 4/0, 336 kcmil, 397 kcmil, and 795 kcmil.

Table 2

Aluminum wire sizes

Size AWG or kcmil	Strand Design (Alum/Steel)	Material ID
336	18/1	9995547
4/0	6/1	8310300
2	6/1	8310800

Distribution Conductor

The other type of aluminum wire is known as All Aluminum Conductor (AAC) which is also stranded wire, but without a steel core. Although not very common, the main size of AAC found on PSE's distribution system is 397.5 kcmil.

Table 3

AAC size

Size (kcmil)	Number of Strands	Material ID
397.5	19	8311700

The only way to visibly tell the difference between ACSR and AAC is to look at an end view, where the ACSR wire's steel core will be evident.

Tree wire is either 336 kcmil or #2 ACSR with a 1/8″ thick covering of black polyethelene. This is typically used in locations with a lot of trees to help cut down on phase-to-phase and phase-to-ground faults.

Size AWG or kcmil	Strand Design (Alum/Steel)	Material ID
336.4	18/1	8309750
#2	6/1	8309730

NOTE: When replacing or repairing tree wire conductor, covered tie wire or special preformed ties must be used and attached to specific insulators designed for tree wire (see page 3 for more information).

Overhead Service Wire is available in various sizes and configurations. It is composed of one or more insulated conductors with one uninsulated neutral conductor as the supporting member.

Table 4

Duplex Wire for Streetlights

Phase Conductors		Bare ACSR Neutral		
Size	Strands	Size	Strands	Material ID
4	7	4	6/1	8319000

Table 5

Triplex Wire for 1/0 Services

Phase Conductors		Bare ACSR Neutral		
Size	Strands	Size	Strands	Material ID
2	7	4	6/1	8318100
2	7	4	6/1	8318101
1/0	7	2	6/1	8318500
4/0	19	2/0	6/1	8318400

Table 6

Quadruplex Wire for 3/0 Services

Phase Conductors		Bare ACSR Neutral		Material ID
Size	Strands	Size	Strands	
2	7	2	6/1	8319100
1/0	19	1/0	6/1	8319500
4/0	19	4/0	6/1	8319700

Tie Wire

Tie wire is required to "tie" conductors to insulators.

For "tying in" all aluminum conductors to standard 12.5 kV distribution insulators, use aluminum tie wire (MID 8313400), or the appropriately sized preformed helical-grip tie. See page 1100-33 of the Electric and Gas Materials Catalog (MatCat).

For "tying in" all copper conductors to standard distribution insulators, use Dead Soft Drawn bare copper wire (MID 8483700).

For "tying in" 34.5 kV wire, preformed ties must be used. See pages 1100-33 and 34 of the MatCat.

Figure 1 Covered Tie Wire

MID 8309760

With the exception of nonmetallic preformed ties, this is the only wire approved to tie tree wire to high-density polyethylene pin-type insulators *(MID 9346050)*.

Covered Flexible Copper Wire

Covered flexible copper wire is used to make ground connections to primary lightning arresters.

Figure 2 Covered Flexible Copper Wire

MID 8441900

AWG #2 insulated flexible copper wire is used when making ground connections to primary lightning arresters. The flexible wire allows the arrestor isolator to hang down after operating indicating the arrester needs replacing.

The conductor is annealed, tin-coated, or uncoated copper with bunched wires and rope-lay stranding. The covering is a minimum of 60 mils thick. The maximum rated circuit voltage is 600 volts.

Primary Splices

Splices are available in PSE's warehouse system to repair most sizes of wire. Make sure you order adequate and appropriate sized splices for each case of damage requiring new insulators and for splicing existing or new conductors. The most common types of automatic tensioning splices are listed below.

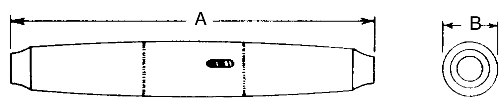
Figure 3 Automatic Tension Splicing Sleeve for Aluminum Conductors

Typical
Automatic Tension Splicing Sleeve for
Aluminum Conductors

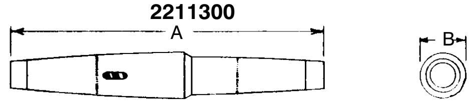
Conductor Size	Strand	Material ID
1/0	7	2214000
4/0	7	2214100
397.5	19	2215400

This sleeve is used for splicing aluminum overhead conductors. The sleeve is high-strength aluminum and is filled with an inhibitor compound.

Figure 4 Automatic Tension Splicing Sleeve for Copper Conductors



2211300



2212300

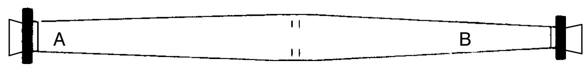
Sleeve	Conductor Range Solid	Strand	Material ID
Automatic	6	8	2211300
Automatic	4	6	2211400
Automatic	2	3	2211500
Automatic	1	2	2211600
Automatic	1/0	1	2211700
Automatic	2/0	1/0	2211800
Automatic	3/0	2/0	2211900
Automatic	4/0	3/0	2212000
Automatic		4/0	2212100
Automatic		500	2212800

Sleeve	Material ID
Reducing 4 Sol to 6 Sol	2212300
Automatic 4/0 Str to 4/0 Sol	2212400

Continued on next page

Primary Splices, *Continued*

Figure 5 Automatic Dual Range Tension Splicing Sleeve for ACSR Conductors

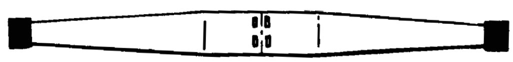


MID 2219100

ACSR Wire Size	Color End A	Color End B	Material ID
#4 - #2	Red/Orange	Red/Orange	2219100

This sleeve is used for splicing #2 ACSR to #4 ACSR overhead conductors in any combination. The sleeve is high-strength aluminum and is filled with an inhibitor compound. It can be used to replace *MIDs 2215000, 2215100, and 2219000*.

Figure 6 Automatic-Tension Splicing Sleeve for ACSR Conductors



Typical
Automatic Tension Splicing Sleeve for ACSR Conductors

ACSR Wire Size	Color	Material ID
#4 (6/1)	Orange	2215000
#2 (6/1)	Red	2219100
2/0 (6/1)	Grey	2215200
4/0 (6/1)	Pink	2215300
336.4 (18/1)	Green	2215400
397.5 (18/1)	Blue	2215500

This sleeve is used for splicing ACSR overhead conductors. The sleeve is high-strength aluminum and is filled with an inhibitor compound. The ends are capped with a color-coded strand-guide cap.

Primary Splices, *Continued*

Figure 7 Service Connectors

Typical
Service Connector

Opening A			Opening B			
ACSR	**Al. or Cu**	**Color**	**ACSR**	**Al. or Cu**	**Color**	**Material ID**
4	4 Str – 2 Sol	Orange		10 Str-8 Sol	Brown	2257200
	3 Str			8 Str-6 Sol	Green	2256300
			6	6 Str-4 Sol	Blue	2257100
			4	4 Str-2 Sol	Orange	2256200
2	2 Str – 1 Sol	Red		8 Str-6 Sol	Green	2257300
			6	6 Str-4 Sol	Blue	2256600
			4	4 Str-2 Sol	Orange	2256500
			2	2 Str	Red	2256400
1/0	1/0	Yellow		8 Str-6 Sol	Green	2255700
			6	6 Str-4 Sol	Blue	2256700
			4	4 Str-2 Sol	Orange	2256800
			2	2 Str	Red	2256900
			1/0	1/0 Str (Al. only)	Yellow	2257000
	2/0	Grey	2	2-1 Str	Red	2257400
			1/0	1/0 Str	Yellow	2257500
			2/0	2/0 Str	Grey	2258800
	3/0	Black	2	2 Str	Red	2257600
			1/0	1/0 Str	Yellow	2257700
				2/0 Str	Grey	2249800
	4/0	Pink	2	2-1 Str	Red	2257800
			1/0	1/0 Str	Yellow	2257900
				2/0 Str	Grey	2250000
				3/0 Str	Black	2249900
				4/0 Str	Pink	2258900

Distribution Insulators

Puget Sound Energy uses a variety of insulator types on the distribution system.

NOTE: For insulators on the transmission system, please see the *Transmission System* tab in this book.

PSE's distribution voltages are 12.5 kV and 34.5 kV. Insulators and pins are coded for each voltage. Note that most insulators are designed for bare wire (copper and ACSR); however, there are different insulators designed for "tree wire."

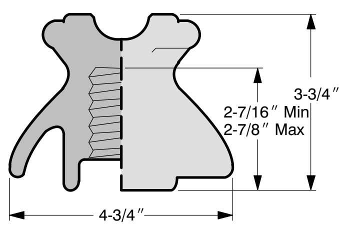
NOTE: Some of PSE's areas have a limited amount of 4 kV, which is being phased out and replaced with 12.5 kV. If you encounter damaged to poles insulated for 4 kV, they should be rebuilt to 12.5 kV standards.

Pin Insulators

Pin insulators are supported by either a wood (old style) or steel pin. In most damage cases, the pin will need to be replaced along with the insulator. There are a variety of pins available, so make sure to choose the correct pin for the application.

Below are examples of the different types of pins and pin insulators.

Figure 1 12.5 kV Insulator



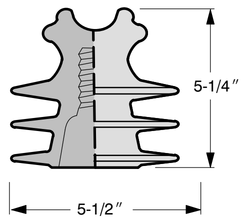
MID 9350300

This porcelain insulator is used on 12.5 kV phase wires. Insulator is installed on a 1-inch diameter pin.

Continued on next page

Pin Insulators,
continued

Figure 2 12.5 kV Insulator for Tree Wire



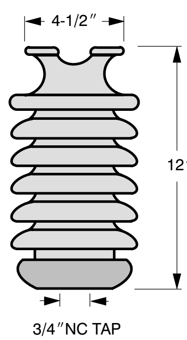
MID 9346050

This insulator is used on 12.5 kV phase wires. Insulator is installed on a 1-inch diameter pin.

The only approved application of this insulator is with tree wire. Tree wire should only be installed with polyethylene insulators, covered tie wire, and/or plastic pre-formed ties.

NOTE: Covered tie wire or plastic pre-formed ties are required to be used when securing tree wire to these insulators.

Figure 3 34.5 kV Insulator

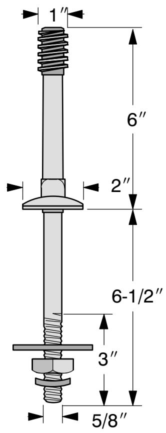


MID 9382100

This tie-top porcelain post insulator is used on 34.5 kV phase wires. Insulator is installed on a 3/4-inch diameter pin.

Pins for Distribution Insulators

Figure 4 6″ Pin with 6-1/2″ Shank

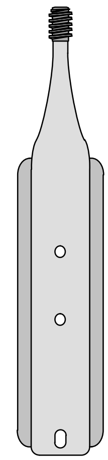


MID 8950700

This insulator pin attaches porcelain or polymer insulators to wood crossarms.

The shank is **not** long enough for the 11-foot heavy-duty deadend arm *(MID 8722400),* or the 13-foot double-deadend arm *(MID 8722000)*. Use *MID 8950800* instead.

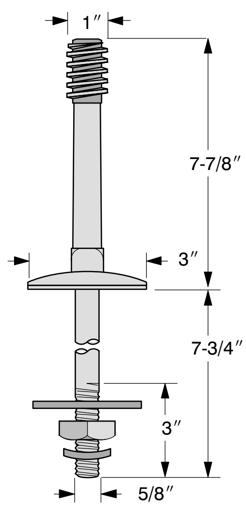
Figure 5 20″ Pole Top Bracket for 12.5 kV Insulators



MID 8960800

This bracket attaches porcelain or polymer insulators to the tops of poles.

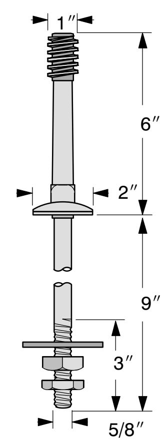
Figure 6 7″ Pin with 7-3/4″ Shank



MID 8950701

This insulator pin is for use on crossarms with a depth of 4-3/4- or 5-3/4-inches, and for insulators requiring a pin with a 7-inch height.

Figure 7 6″ Pin with 9″ Shank



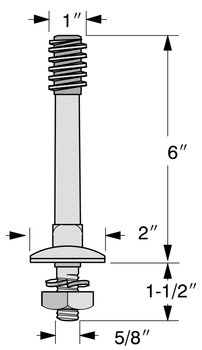
MID 8950800

This insulator pin attaches porcelain or polymer insulators to the 11-foot heavy-duty deadend arm *(MID 8722400),* and the 13-foot double-deadend arm *(MID 8722000)*.

Continued on next page

Pins for Distribution Insulators, *Continued*

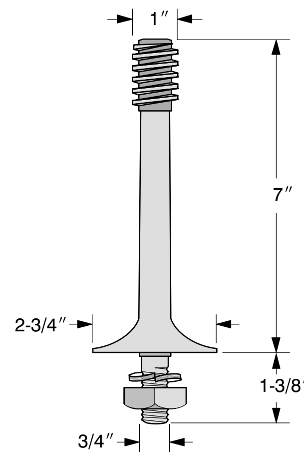
Figure 8 6″ Pin with 1-1/2″ Shank



MID 8950500

These steel pins are used on overhead distribution with fiberglass arms when two insulators are required on angle construction.

Figure 9 7″ Pin with 1-3/8″ Shank

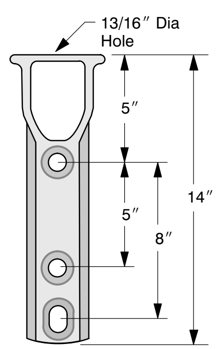


MID 8951300

This insulator pin attaches porcelain or polymer insulators to epoxirod sidemount arms or 34.5 kV pole top brackets.

Some insulators are mounted on the top of a pole on a bracket called a Pole Top Pin.

Figure 10 14″ Pole Top Bracket for 34.5 kV Insulators



MID 8768700

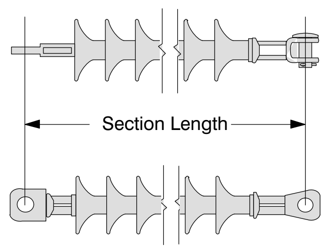
This insulator pin adapter uses porcelain or polymer insulators with 1-inch internal threads, and 5/8-inch diameter bolts to support down leads and jumpers.

Distribution Suspension Insulators

Suspension insulators used on the distribution system are made of silicone rubber, and are used for dead-end and corner applications.

There are two coded distribution suspension insulators.

Figure 11 Suspension Insulators



12.5 kV — MID 9389100
34.5 kV — MID 9389000

Other Insulators

Rigid Clevis

The rigid clevis is used to support the neutral when it is in the common (lower) position, and is also used to deadend or support overhead services and secondaries.

Figure 12 Rigid Clevis

MID 9257200

Service Knob

The service knob is used to support or deadend 600 volt or less overhead services.

Figure 13 Service Knob

MID 9412900

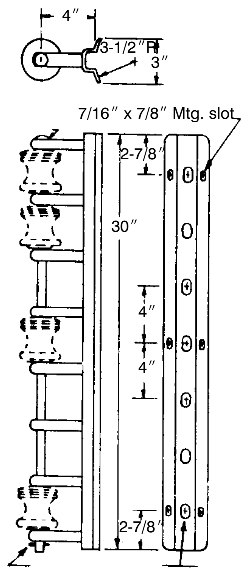
Continued on next page

Other Insulators, *Continued*

Four Spool Secondary Rack

These were once used to attach secondary wires from three phase transformer banks, neutral conductors and multiple services. These secondary racks can be reused if in good shape, or replace them with a rigid clevis (see above).

Figure 14 Four-Spool Secondary Rack



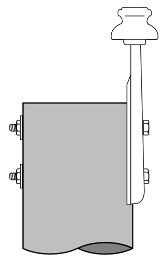
MID 8773100

Insulators

Pin and Insulator Assemblies

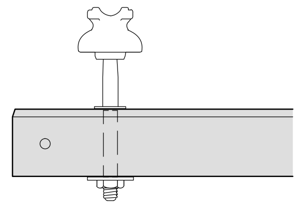
Below are some of examples of various pin and insulator assemblies to help in ordering the correct parts.

Figure 15 12 kV Single Pole Top Pin



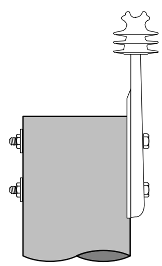
DESCRIPTION	MID	QTY
Insulator	9350300	1
Pole Top Pin	8960800	1
10″ Bolt	1241700	2
Square Washer	9102600	2

Figure 16 12 kV Arm-Mounted Pin



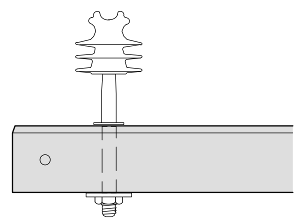
DESCRIPTION	MID	QTY
Insulator	9350300	1
Pin	8950700	1

Figure 17 12 kV Single Pole Top Poly Pin Insulators Used for Tree Wire



DESCRIPTION	MID	QTY
Insulator	9346050	1
Pole Top Pin	8960800	1
10″ Bolt	1241700	2
Square Washer	9102600	2
Covered Tie Wire	8309760	as needed

Figure 18 12 kV Mounted Poly Pin Insulators Used for Tree Wire



DESCRIPTION	MID	QTY
Insulator	9350300	1
Pin	8950700	1
Covered Tie Wire	8309760	as needed

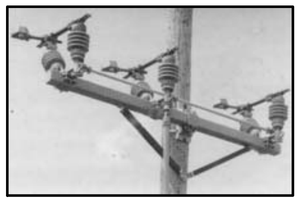
Notes:

Switches

Gang Operated

Gang operated switches are used in three-phase situations, and operate all three phases simultaneously from a single control handle. If a pole with a gang operated switch is knocked down, the switch will likely be damaged. The linkage running up the pole can also be damaged. Unless you are sure the switch and linkage is reusable, include a replacement switch when requesting the material needed at that location.

Figure 1 3PST Pole-Mount Switches



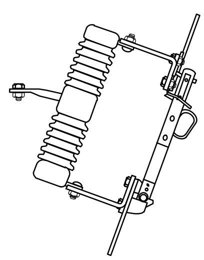
MID 5069000
12.5 kV 3PST Switch

System Voltage	Material ID
12.5 kV	5069000
34.5 kV	5070200

Solid Blade

Solid blade disconnects are operated on an individual basis, independent of each other. These can be used for single- or three-phase construction. They are also used for sectionalizing portions of lines and as disconnect switches for 600 A terminations.

Figure 2 New Style SPST Cutout Crossarm-Mounted Switch



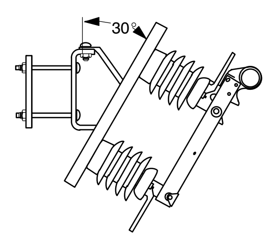
MID 9995955
15 kV Cutout Switch

System Voltage	Current Rating	Material ID
12.5 kV	600 A	9995955

This SPST cutout switch is used on 600 A terminal poles for equipment bypass and sectionalizing applications. The switch has hooks for breaking load with S&C's "Loadbuster" tool.

Crossarm mounting bracket is not included. To mount on a crossarm, order mounting bracket *MID 9995886*.

Figure 3 Old Style SPST Crossarm-Mount Switches



MID 4955500
12.5 kV Crossarm-Mount Switch

System Voltage	Current Rating	Material ID
12.5 kV	600 A	4955500
34.5 kV	600 A	4955600

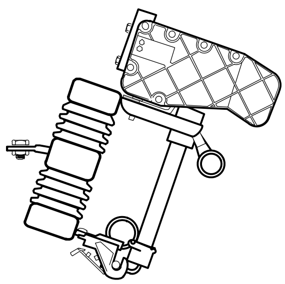
These SPST switches are used as equipment bypass switches and for disconnects on 600 A terminal poles. The switch has hooks for breaking load with S&C's "Loadbuster" tool.

All 12.5 kV switches are supplied with a 30° angle mounting bracket. The 34.5 kV switch is designed for vertical mounting.

Fused Cutouts

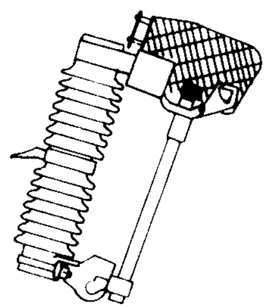
Fused cutouts are installed as protection devices for transformers, capacitors, and lines (laterals). Some single-phase fused cutouts are "load break cutouts," designed to minimize any arcing when the switch is opened under load. These cutouts have flash guards, also called "elephant ears," which extinguish the arc when opened under load.

Figure 4 34.5 kV Load Break



MID 4898500

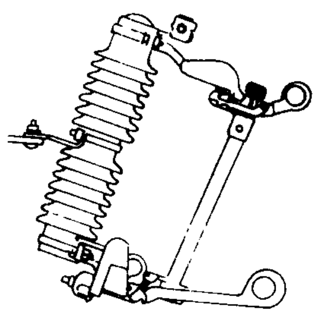
Figure 5 12.47 kV Load Break



MID 4898100

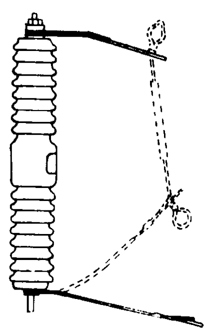
Other fused single-phase cutouts are "link break cutouts," which do not have load-interrupting capability unless used with a loadbuster tool.

Figure 6 12.47 kV Link Break



MID 4899000

Figure 7 Grasshopper or Trip-O-Link Cut Out



Fuse Sizes

The capacity of the fuse is imprinted on the end cap. If the fuse had “blown” this information may not be available on site. Consult the overhead circuit map for fuse sizes for laterals. For overhead transformers, use the following chart to determine the correct fuse size.

Table 1

Fusing for single- and three-phase applications on overhead transformers. Transformers in three-phase banks shall be fused according to their ***individual*** sizes.

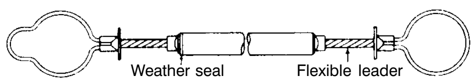
Transformer Size	2,400 V Single-Phase Transformers	7,200 V Single-Phase Transformers	19,920 V Single-Phase Transformers
	Expulsion Fuse	Expulsion Fuse	Expulsion Fuse
1.5	2T	2T	—
3	6T	2T	—
5	10T	2T	1H
7.5	15T	6T	—
10	15T	6T	2H
15	15T	6T	2H
25	25T	10T	5H
37.5	40T	15T	6T
50	65T	15T	8T
75	65T	25T	10T
100	100T	40T	15T
167	*140T	65T	25T
250	*140T	65T	25T
333	*140T	65T	25T
500	—	100T	40T

* Check with System Protection Group before using 140T fuses

Fuse Links

Fuse links (grasshoppers) were used to protect transformers up to 25 kVA, but are being phased out. If a new transformer is needed, replace the fused cutout as well. If you come across a situation where the transformer and cutout are still OK for use, a replacement fuse link may be used. However, if a crew needs to work on the pole, use this opportunity to have the cutout replaced.

Figure 8 Fuse Links (Grasshoppers)



Typical
Fuse Link

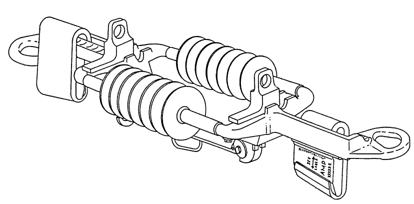
Ampere Rating	Material ID
2 A	3344100
6 A	3344200
10 A	3344300
15 A	3344400
25 A	3344500

These fuse links are used only as replacements in open link 7.2 and 12.5 kV cutouts to protect distribution transformers up to 25 kVA where the required fuse-carrying capacity rating does not exceed 50 Amp. Fault interrupting capability is up to 1200 Amp. They are not to be used for fusing laterals.

In-Line Disconnect Switch

You may find the occasional use of in-line disconnect switches in the field. They are sometimes used to isolate sections of lines during construction and maintenance operations, and are also used occasionally as bypass switches. Unless the in-line disconnect switch is in use as a bypass switch, it does not need to be replaced in the field. However, make sure you note on the damage assessment form that such switch is not being replaced. Below is an example of an in-line disconnect switch.

Figure 9 Line-Tension (In-Line) Disconnect Switch



MID 5069500
Disconnect Switch

System Voltage	Wire Size	Material ID
12.5 kV	336.4 ACSR	5069500
	397.5 AAC	

Transformers

When a transformer is knocked to the ground, an oil spill can occur. Oil spills must be reported to the Operating Base as soon as possible and must be noted on the Damage Assessment Form.

Figure 1 Downed Pole with Transformer

The operating base needs to know the size and voltages of any and all transformers that need to be replaced.

Overhead transformers come in a variety of sizes, ranging from 10 kVA up to 167 kVA, as well as single and two bushing configurations. Some transformers will have the kVA rating marked on the side of the tank and others will have an alpha designation. The most common sizes of overhead transformers are:

J = 10 kVA	L = 15 kVA	N = 25 kVA	P = 37.5 kVA
R = 50 kVA	S = 75 kVA	T = 100 kVA	UL = 167 kVA

Figure 2 Overhead Transformer with One Primary Bushing
120/240 Volt Secondary

	High-Voltage			
kVA	**4,160GrdY /2,400 x 12,470GrdY /7,200**	**12,470GrdY /7,200**	**12,470GrdY /7,200 x 34,500GrdY /19,920**	**34,500GrdY /19,920**
15 kVA	6207150	6211200	6217050	6221050
25 kVA	6207200	6211250	6217100	6221100
37.5 kVA	6207250	6211300	6217150	6221150
50 kVA	6207300	6211350	6217200	6221200
75 kVA	6207350	6211400	6217250	6221250
100 kVA	6207400	6211450	6217300	6221300
167 kVA	6207450	6211550	6217350	6221350

Typical
120/240 V, 167 kVA Secondary
One-Bushing Transformer
(Note: May also be used for 208Y/120Y services)

Transformers, *Continued*

Figure 3 Overhead Transformer with One Primary Bushing
120/208Y Volt Secondary

kVA	High-Voltage 4,160GrdY /2,400 x 12,470GrdY /7,200	12,470GrdY /7,200	12,470GrdY /7,200 x 34,500GrdY /19,920
15 kVA	6205150	6209100	6215150
25 kVA	6205200	6209150	6215200
37.5 kVA	6205250	6209200	6215250
50 kVA	6205300	6209250	6215300
75 kVA	6205350	6209300	6215350
100 kVA	6205400	6209350	6215400
167 kVA	*	*	*

*Order the equivalent transformer listed in the 120/240 low-voltage section above. These 167 kVA transformers have each of the four secondary-winding leads brought out to separate terminals. External connection for either 120/240- or 208Y/120-volt operation is made by service crew.

Typical
120/240 V, 50 kVA
One-Bushing Transformer

Figure 4 Overhead Transformer with Two Primary Bushings
120/240 Volt Secondary

kVA	High-Voltage 2,400/ 4,160Y x 7,200/ 12,470Y	7,200/ 12,470Y
15 kVA	6208150	6212150
25 kVA	6208200	6212200
37.5 kVA	6208250	6212250
50 kVA	6208300	6212300
75 kVA	6208350	6212350
100 kVA	6208400	6212400
167 kVA	6208450	6212500

Typical
120/240 V, 34.5 kVA
Two-Bushing Transformer

Transformers, *Continued*

Figure 5 Overhead Transformer with Two Primary Bushings
240/480 Volt Secondary for State Highway Lighting

	High-Voltage	
kVA	**2,400/ 4,160Y**	**7,200/ 12,470Y**
25 kVA	6203150	6213100
50 kVA	6203250	6213200
100 kVA		6213300
167 kVA	6203450	6213350

These overhead transformers are single-phase units which may be used for single-phase applications or interconnected for three-phase applications.

Transformers with two high-voltage bushings are designed for three-phase ungrounded-wye primary system banks (such as closed- delta secondary banks). These transformers can also be used in place of single-bushing transformers if necessary, but single-bushing transformers cannot be used for three-phase ungrounded-wye connected banks.

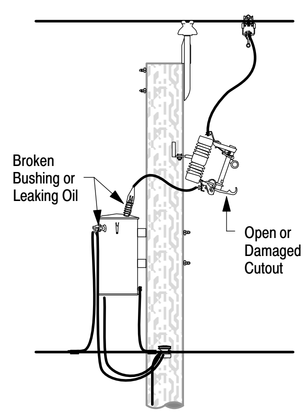
Typical
240Y/480 V, 25 kVA
Two-Bushing Transformer

NOTE: PSE's preferred installation practice is to use a single-bushing transformer when replacing a two bushing transformer on a single-phase line with the neutral in the primary (on the crossarm) position. To do this, the neutral must be in the common (lower) position. Note on the Damage Assessment form whether it will be possible to roll the primary neutral to the common position to accommodate the use of a single-phase transformer.

If possible, note the secondary voltage of distribution transformers, which can be found on the transformer nameplate. You may also find a sticker with the secondary voltage configuration on the center transformer of a three-phase bank. Single transformers serving residential customers will be 120/240 volts on the secondary side.

Because transformer cutouts are often broken, order a new transformer cutout when calling for a transformer.

Figure 6 Transformer and Cutout on Pole

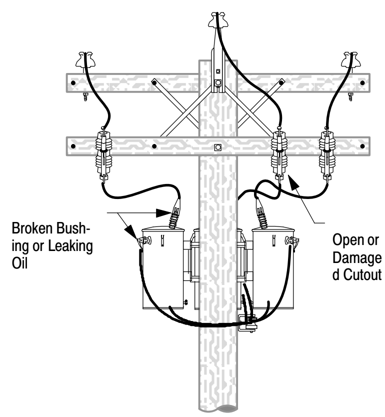


Overhead Transformer Bank

Some commercial applications use three transformers banked together for three-phase power, or two transformers banked together as part of an open delta configuration. Note the size of each transformer.

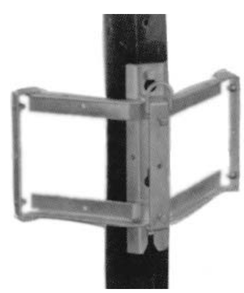
Transformers making up a transformer bank may or may not all be the same size (kVA rating), depending on application. Note the size of each transformer in the bank.

Figure 7 Transformer Bank



Banked transformers are mounted on a "cluster rack" on the pole.

Figure 8 Transformer Cluster-Mount Bracket and Adapter Plate



MID 5135000
XFMR Cluster-Mount
Bracket

Bracket Type	Material ID
Transformer Cluster-Mount Pole Bracket, 750 lbs per position for type "A" lugs	5135000
Transformer Cluster-Mount Pole Bracket, 2500 lbs per position for type "A" and "B" lugs	5148300

Padmount Transformer

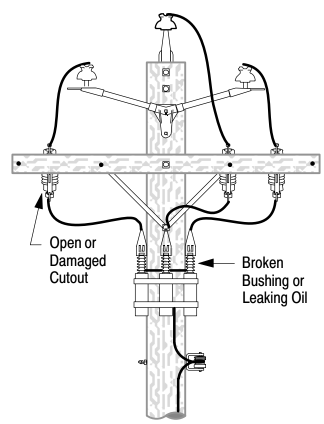
Occasionally a padmounted transformer may be damaged during a storm and have to be replaced. In most cases, existing hardware (elbows, grounds, vaults, etc) may be reused.

The primary voltage will be noted on the transformer case, usually in yellow paint. The secondary voltage will be noted on the transformer nameplate. If the transformer is serving residential customers, it will be 120/240 volts on the secondary side. This information is needed by the operating base so the correct replacement transformer size can be ordered.

Line Capacitors

PSE has installed distribution line capacitors in many locations. These are rectangular “cans” with fuses, mounted in a rack of three.

Figure 9 Line Capacitor



Recently installed capacitors are PCB-free, but it is possible that older units may contain PCBs. If it is not labeled “CONTAINS NO PCBs,” exercise caution around the units. If any capacitors are ruptured and/or leaking fluid, report this as a hazardous condition (oil spill).

NOTE: Replacement of a capacitor bank on a distribution line is not considered “mission critical” in storm restoration efforts. However, it is imperative that the damage be noted on the D/A form so follow-up restoration can be accomplished.

Notes:

Regulators, Reclosers, and Sectionalizers

This section covers other PSE-owned distribution line equipment on a pole, such as voltage regulators, line reclosers and sectionalizers.

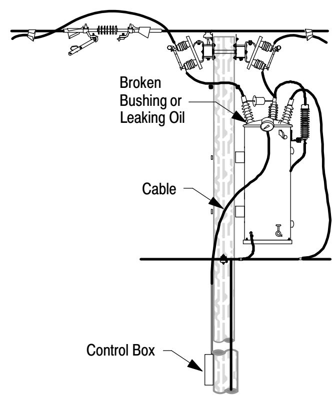
⚠ CAUTION!

Regulators, reclosers (non-vacuum), sectionalizers, and autoboosters contain insulating oil. If an oil spill has occurred, it must be reported to the operating base as soon as possible.

Regulators and Autoboosters

In some instances, line voltage regulators are installed on poles. They look like overhead transformers, but are larger and taller, usually with some type of cooling fins or radiators. They also have a large dial on the side, visible from the ground, showing the step position of the regulator.

Figure 1 Regulator



Occasionally, you may find an autobooster installed in the field. An autobooster looks a lot like a small single-phase transformer with a dial indicator similar to a voltage regulator.

NOTE: Autoboosters are no longer stocked in Stores. If an autobooster fails, it should be replaced with a single phase regulator. Contact Electric First Response Engineering for assistance.

Reclosers

There are two types of reclosers on PSE's system: oil filled and vacuum type. Both types of reclosers are identified by the control box mounted approximately 10 feet above ground. Oil reclosers are no longer stocked in Stores and should be replaced with vacuum reclosers.

Figure 2 Recloser (Oil-Filled)

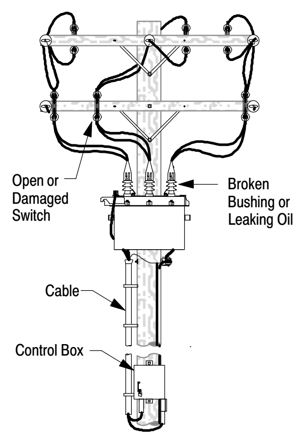
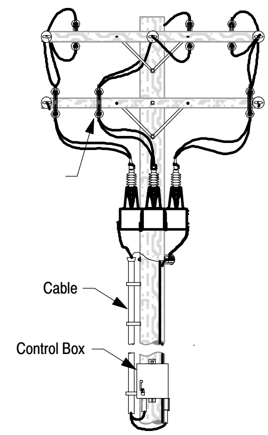


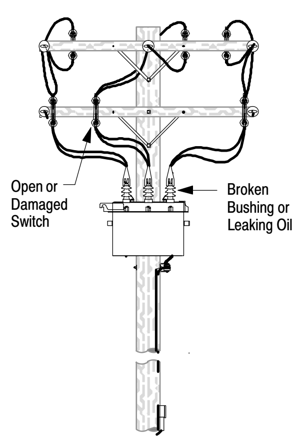
Figure 3 Recloser (Vacuum)



Sectionalizers

A sectionalizer looks very much like an oil-filled recloser, but it is smaller and does not have a control box mounted down on the pole.

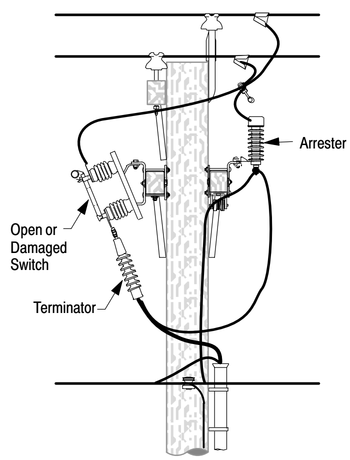
Figure 4 Sectionalizer (Oil-Filled)



Underground Risers

Poles with an underground terminations can be damaged during a storm. This pole will have conduit, standoff brackets, and underground cable with a termination at the top that connects it to the overhead fused cutout. There also will be a lightning arrester in parallel. Be sure to note all of these materials on the D/A form.

Figure 1 Termination/Riser



Conduit

Underground conductor, either primary or secondary, will be routed up a pole in conduit. Although many variations of construction will be evident in the field, PSE currently uses Schedule 80 PVC for the first 10 feet aboveground, and DB-120 for the rest of the application. Conduit is stocked in five sizes: 1″, 2″, 3″, 4″, and 6″.

If the underground conductor is enclosed in a continuous conduit system, a 90-degree bend will be required.

If the underground conductor is direct buried, a 90-degree bend is not required (but may be installed anyway). The conductor is trained into a 90-degree turn and fed directly into the bottom of the conduit system.

⚠ CAUTION!

Some older conduit was made out of a material called transite, which contains asbestos. This is a rough-textured gray material, unlike more-common PVC conduit. If you encounter any damaged transite conduit, it must be reported to the operating base so proper disposal can be arranged. If a piece of transite conduit is blocking the roadway, try to push it out of the way with a shovel or similar tool. ***Do not handle transite conduit unless you are trained and equipped to do so.***

Fittings

A variety of fittings are stocked at warehouses, including couplings, standoff brackets and clamps.

Standoff Brackets

Standoff brackets are available in two lengths, 15″ and 24″. In the field, the majority of standoff brackets are 15″. The size to be used is determined by the number of conduit risers that will be attached to the pole. Typically four brackets are needed per pole, including one that is to be installed 6″ belowgrade.

Clamps

Conduit clamps are sized according to the diameter of the conduit.

NOTE: On service poles only, conduit straps may be used to attach conduit risers directly to the pole surface if there will not be multiple risers.

Bell Ends

A bell end (bushing) is required at the top of the conduit riser.

Riser Assemblies

The following table lists, by conduit diameter, all of the components necessary for riser assemblies.

2″ RISER

Description	Material ID	QTY
2″ DB120 PVC	7634800	20
2″ Schd 80 Bend	7645201	1
2″ Bellend	7624500	2
2″ Schd 80 PVC	7642200	10
Lag Screw	9995734	8
Stndoff brkt	7627300	4
2″ Clamp	7632400	4

3″ RISER

Description	Material ID	QTY
3″ DB120 PVC	7634900	20
3″ Schd 80 Bend	7645301	1
3″ Bellend	7624600	2
3″ Schd 80 PVC	7642300	10
Lag Screw	9995734	8
Stndoff brkt	7627300	4
3″ Clamp	7633300	4

4″ RISER

Description	Material ID	QTY
4″ DB120 PVC	7635000	20
4″ Schd 80 Bend	7645401	1
4″ Bellend	7624700	2
4″ Schd 80 PVC	7642400	10
Lag Screw	9995734	8
Stndoff brkt	7627300	4
4″ Clamp	7633400	4

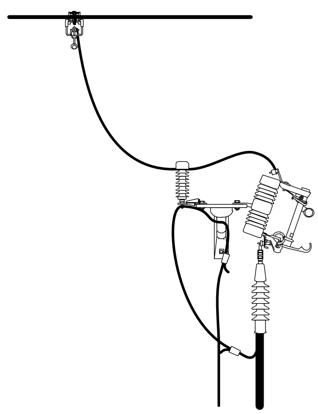
6″ RISER

Description	Material ID	QTY
6″ DB120 PVC	7635100	20
6″ Schd 80 Bend	7645601	1
6″ Bellend	7624900	2
6″ Schd 80 PVC	7642600	10
Lag Screw	9995734	8
Stndoff brkt	7627300	4
6″ Clamp	7633600	4

Terminations and Lightning Arresters

All underground primary cable uses a termination to connect the cable to the overhead cutout. If repairing a damaged pole with an underground riser, and the primary cable cannot be reused, a new run of cable and new termination will have to be installed.

Figure 2 Single Phase 12.5 kV 1/0 Termination



DESCRIPTION	MID	QTY
Termination Kit	7852000	1
Pin terminal	7849200	1
Arrestor	4824100	1
Cutout	4899000	1
Flex wire	8441900	6
L Bracket	9995886	2

Figure 3 12.5 kV and 34.5 kV Cable Terminations

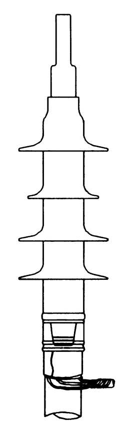
12.5 kV Terminations

Conductor Size	Cable Type	Material ID
#2 – 4/0	Concentric Neutral	7852000
4/0 – 500 kcmil	Tape shield	7852140
500 – 1000 kcmil	Tape shield	7852150

34.5 kV Terminations

Conductor Size	Cable Type	Material ID
1/0 – 4/0	Concentric Neutral	7852100
3/0 – 600 kcmi	Tape shield	7852160

For terminating a #2 - 1/0, butyl-insulated, tape-shield cable, use *MID 7852000* and order a tape-shield adapter kit *MID 9995507*.



Typical
Cable Termination

Continued on next page

Terminations and Lightning Arresters, *Continued*

Pole mounted distribution lightning arresters are used to protect underground cables at terminal poles. These are required on all underground terminations, including both 12.5 kV and 34.5 kV.

Figure 4 Distribution Lightning Arresters

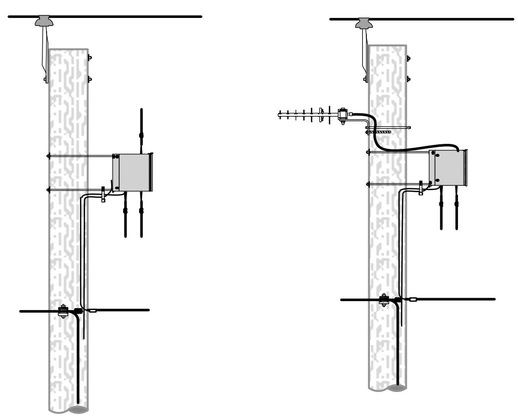
System Voltage	Type	Material ID
7.2/12.5 kV	Pole Mounted	4824100
19.9/34.5 kV	Pole Mounted	4825200

MID 4824100
12 kV Heavy-Duty Arrester

AMR

PSE uses an Automated Meter Reading (AMR) system to "read" customers' meters and electronically transmit the data back to PSE. To do this, there are a number of AMR pole top units installed on distribution power poles. These pole top units collect data and transmit it on to an AMR Control System, which is also found on a pole.

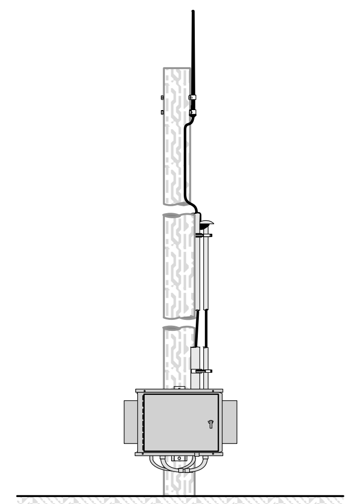
Figure 1 AMR Pole Top Units



Standard Install with Omni Antenna

Standard Install with Directional Antenna

Figure 2 AMR Control Station



Important Note About AMR Equipment

It is a requirement to note on the D/A form any AMR equipment affected. Undamaged AMR equipment may be reused but it still must be reported. If AMR equipment is found on damaged or downed poles, immediately call the CellNet/Schlumberger-Sema Hotline at **1-866-662-7762.**

Identify yourself as a PSE Damage Assessor reporting downed equipment for the PSE AMR Project. Be prepared to provide the following information.

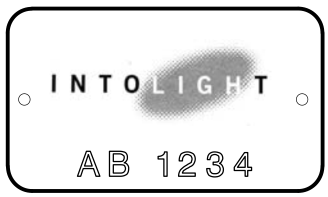
- Equipment type and ID Number:
  - Pole top units have a 5-digit code on the cabinet front,
  - Control Stations are identified by their location.
- Pole Location by address or cross streets.
- Pole Grid Number ID.

Control stations without power should be reported to the Damage Assessment Supervisor.

Streetlights

All damaged streetlights should be noted on the D/A form. Include the Intolight number, if possible. Typically, Intolight handles all streetlight repair and replacement. However, if a streetlight is not damaged and is reuseable, the responding line crew may reinstall it. Make sure you note this on the damage assessment form.

Figure 3 Aluminum Streetlight ID Tag



MID 9995260

Figure 4 Film Streetlight ID Tag

MID 9995731

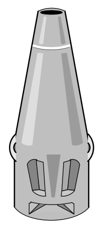
Figure 5 Example of a Film Streetlight ID Tag on a Pole

Avian and Wildlife Protectors

PSE uses a variety of avian and wildlife protection devices. These devices are found on insulators, crossarms, and conductors. Avian and wildlife protectors may be reused if they are not damaged.

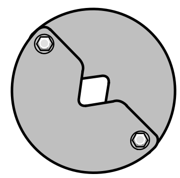
While it is not essential to immediately replace such equipment during major outage restoration efforts, it is very important to note on the damage assessment form any damaged avian and wildlife protection devices for eventual replacement.

Figure 6 Examples of Equipment Wildlife Protectors



MID 3450000
Overhead Equipment

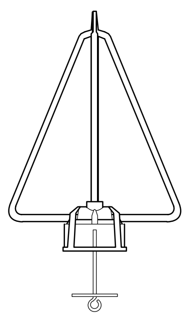
MID 9996101
Tyco Overhead Equipment



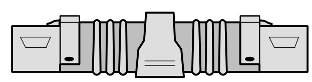
MID 9995994
E/Barrier

MID 9996514
Tyco Cutout Protector

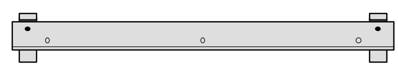
MID 9996143
Firefly Bird Flapper Swivel



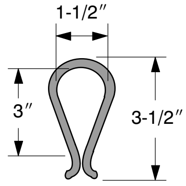
MID 9996146
MID 9996147
Antiperch Triangles



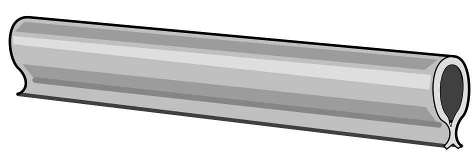
MID 9996213
Tyco Pin Protector



MID 9996214
Tyco Wire Protector



Line-Duc End View

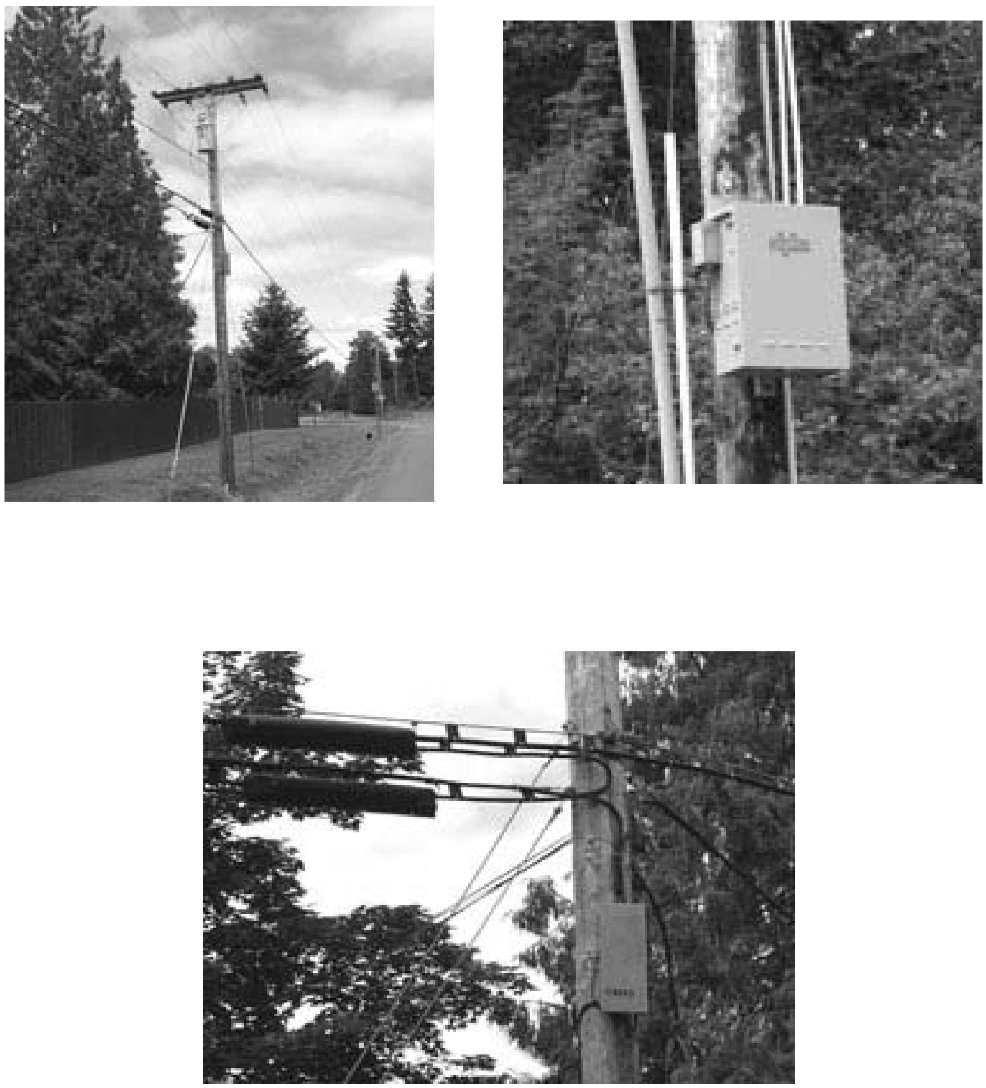


MID 9995986
Line-Duc

Non-PSE Equipment on Pole

There is often other equipment attached to PSE poles, usually belonging to cable and telecommunications companies. This equipment and conductor is attached to PSE poles below the neutral conductor. Note this on the D/A form so that the operating base may notify the other utility.

Figure 7 Examples of Other Equipment on Poles



Damage Assessing on the Transmission System

This is a specialized type of damage assessment, typically performed by transmission engineers and planners and/or others that have had extensive experience in this area.

However, in a very large event or an event that impacts a large portion of the transmission system, other “less-experienced” folks may be pressed into duty. This section of the Damage Assessment Guide is intended to give a brief overview of typical transmission construction practices.

Many of PSE’s transmission lines are routed “cross country” on rights-of-way that are not necessarily vehicle-accessible. This may mean a lot of foot-patrolling, so dress accordingly and be prepared.

NOTE: PSE’s system still contains some 55 kV, which is being phased out and replaced with 115 kV. If you encounter damage to poles insulated for 55 kV, they should be rebuilt to 115 kV standards.

Transmission Poles

Transmission poles vary in height. Most are 65′–85′ and taller, but in some cases, they can be as tall as 120′. Conductors are attached to transmission poles in various configurations.

Figure 1 HPA

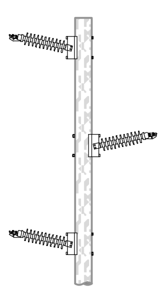


Figure 2 Vertical Turn

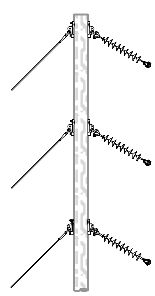


Figure 3 Vertical Deadend

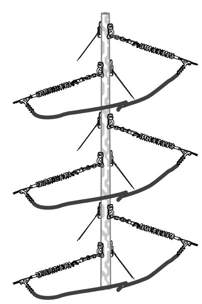
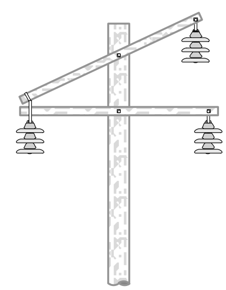


Figure 4 Wishbone



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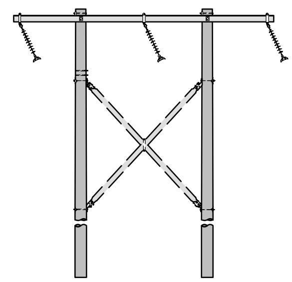
Transmission Poles, *Continued*

Some transmission lines use a double pole arrangement, with a large crossarm between them and insulators hanging down. This is called an “H” Structure. The crossarms used in this construction are typically much larger than normal crossarms.

Figure 5 “H” Structure



Call for a pole ground assembly for every pole that needs replacing in the field, including all transmission poles. See the “Pole Grounds” and “Guy Wire” sections in the *Miscellaneous* tab.

Transmission Crossarms

Crossarms used on the transmission system are “heavier” (width and depth) than distribution arms and much longer, ranging from 14′-39′ in length.

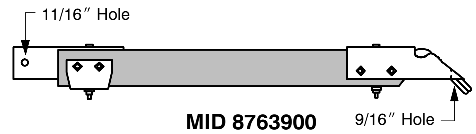
Table 1

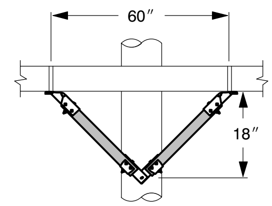
Voltage	Description	Length	Width	Depth	Material ID
115 kV	Heavy-Duty Deadend	8′	7-1/2″	5-5/8″	8730700
115 kV	Heavy-Duty Deadend or Wishbone	14′	3-5/8″	9-1/2″	8733700
115 kV	Types AB, DA – H-Structure	24′	3-5/8″	9-1/2″	8734150
230 kV	Type AR S&W Engineering	39′	3-5/8″	9-1/2″	8734300
230 kV	Type B2 S&W Engineering	39′	3-5/8″	11-1/2″	8734800
230 kV	Heavy-Duty Type DE-4	15′ 6″	10″	9″	8734900
115 kV	Types A, B, DA, E – H-Structure	24′	7-1/2″	7-1/2″	8735000
115 kV	Type DC – H-Structure	24′	6-1/2″	9-1/2″	8735100
115 kV	Type G – H-Structure	16′	3-5/8″	9-1/2″	8735300
115 kV	Types D, F, & Transmission Towers	26′	3-5/8″	9-1/2″	8735400
115 kV	Types G2, G2A – H-Structure	28′	3-5/8″	9-1/2″	8735500

Transmission Crossarm Braces

Crossarm braces used on the transmission system include two “standard” types of braces.

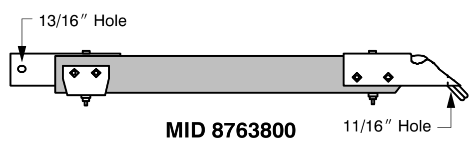
Figure 6 115 kV Heavy-Duty Deadend Crossarm Brace

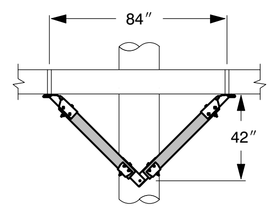




These braces stabilize heavy-duty deadend arms. The braces are designed for an 18-inch drop and 60-inch span. Brace timber has a finished dimension of 1-5/8 x 2-1/4 inches. Supplied as a set, one brace each for left and right. All metal is galvanized. Wood is treated with preservatives. All fittings are static-proof.

Figure 7 115/230 kV Deadend Crossarm Brace





These braces stabilize 115 and 230 kV crossarms. The braces are designed for a 42-inch drop and 84-inch span. Brace timber has a finished dimension of 2-3/4 x 3-1/2 inches. Supplied as a set, one brace each for left and right. All metal is galvanized. Wood is treated with preservatives. All fittings are static-proof.

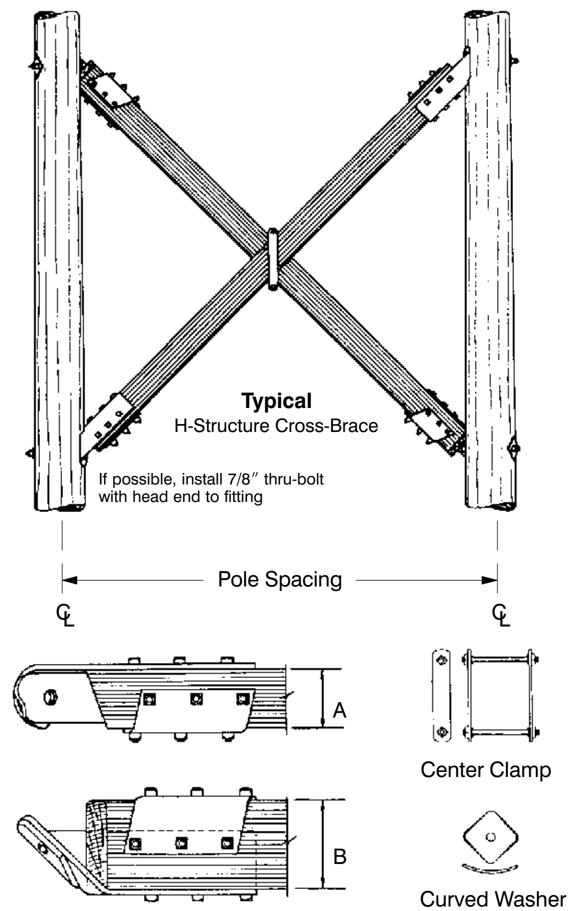
Continued on next page

Transmission Crossarm Braces, *Continued*

H-structure cross-braces are also used and include all necessary hardware.

Figure 8 H-Structure Cross-Braces

Pole Spacing	Dimensions A	Dimensions B	Number of Bolts	Material ID
11′-6″	3-3/8″	4-3/8″	4	8764200
12′-6″	3-3/8″	4-3/8″	4	8764300
13′-6″	3-3/8″	4-3/8″	4	8764400
14′-6″	3-3/8″	4-3/8″	4	8764500
15′-6″	3-3/8″	5-3/8″	4	8764600
19′-0″	3-3/4″	5-3/4″	4	8764900
21′-0″	3-3/4″	5-3/4″	4	8765000
23′-0″	3-3/4″	5-3/4″	4	8765100
13′-6″	3-11/16″	8-1/2″	8	8763001
16′-6″	3-11/16″	8-1/2″	8	8763002
19′-0″	3-11/16″	8-1/2″	8	8763003
21′-0″	3-11/16″	8-1/2″	8	8763004



Cross-braces are supplied in sets with pole mounting hardware including center clamp, 4-inch curved square washers, and 7/8-inch bolts with MF locknuts. Fifty percent of bolts are 16-inch and fifty percent are 18-inch. All metal is galvanized. Wood is treated with preservatives.

Cross-braces are ordered by the design centerline-to-centerline pole spacing for any multipole structure.

Transmission Insulators

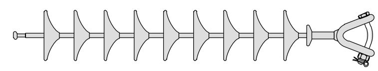
Transmission line insulators come in two different types: suspension and horizontal line post. Both types come in different sizes for 115 kV and 230 kV.

Suspension Insulators

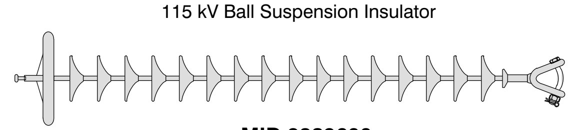
These insulators are used on poles that are “turn” poles, (i.e., not tangent). They are also used in “wishbone” applications. For examples, see *Figures 2, 3, and 4*.

Figure 9 Suspension Insulators

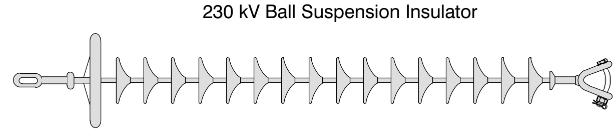
Nominal System Voltage	Horizontal Coupling/ Section Length	Material ID
115 kV	41″- 47″	9388000
230 kV	74″- 80″	9389600
230 kV	77″- 83″	9995751



MID 9388000
115 kV Ball Suspension Insulator



MID 9389600
230 kV Ball Suspension Insulator



MID 9995751
230 kV Oval-Eye Suspension Insulator

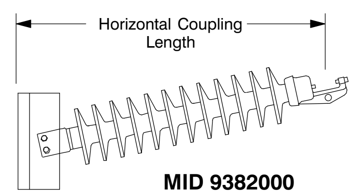
Horizontal Post Insulators

These types of insulators are used on tangent poles. See *Figure 1* for an example of an HPA.

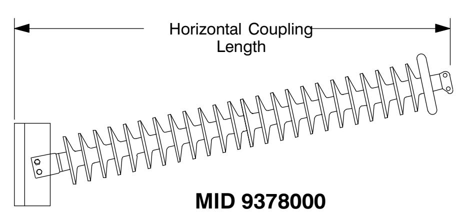
Figure 10 115 kV and 230 kV Horizontal Line Post Insulators

Nominal System Voltage	Horizontal Coupling Length	Base Type	Material ID
115 kV	42″ - 48″	Gain Channel	9382000
115 kV	42″ - 48″	Flat	9382001
230 kV	73″ - 79″	Gain Channel	9378000
230 kV	73″ - 79″	Flat	9378001
230 kV	73″ - 79″	Gain Channel	9996211

“Flat” base type is for laminated or steel poles.
“Gain channel” base type if for round wood poles.



MID 9382000
MID 9382001
115 kV Trunnion
Horizontal Post Insulators



MID 9378000
MID 9378001
MID 9996211
230 kV Extended Two-Hole
115 kV Horizontal Post Insulators

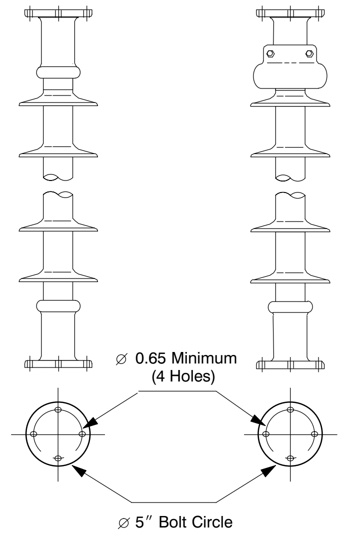
Continued on next page

Horizontal Post Insulators, *continued*

Transmission lines are occasionally constructed with vertical line post insulators. For example, these applications are used when a transmission line must be lowered for clearance under another line.

Figure 11 115 kV and 230 kV Vertical Line Post Insulators

Nominal System Voltage	Height	Material ID
115 kV	45″	9373001
230 kV	80″	9373499



MID 9373001
115 kV Vertical
Post Insulator

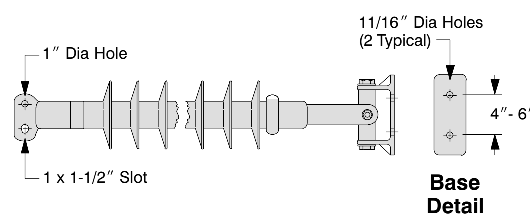
MID 9373499
230 kV Vertical
Post Insulator

Strut Insulators

Strut insulators are used on the transmission system, in applications such as “H” structures, when a conductor must be captured in place and prevented from moving sideways.

Figure 12 Strut Insulator

Nominal System Voltage	Horizontal Coupling Length	Material ID
115 kV	61″	9997363
230 kV	84″to 86″	9378002

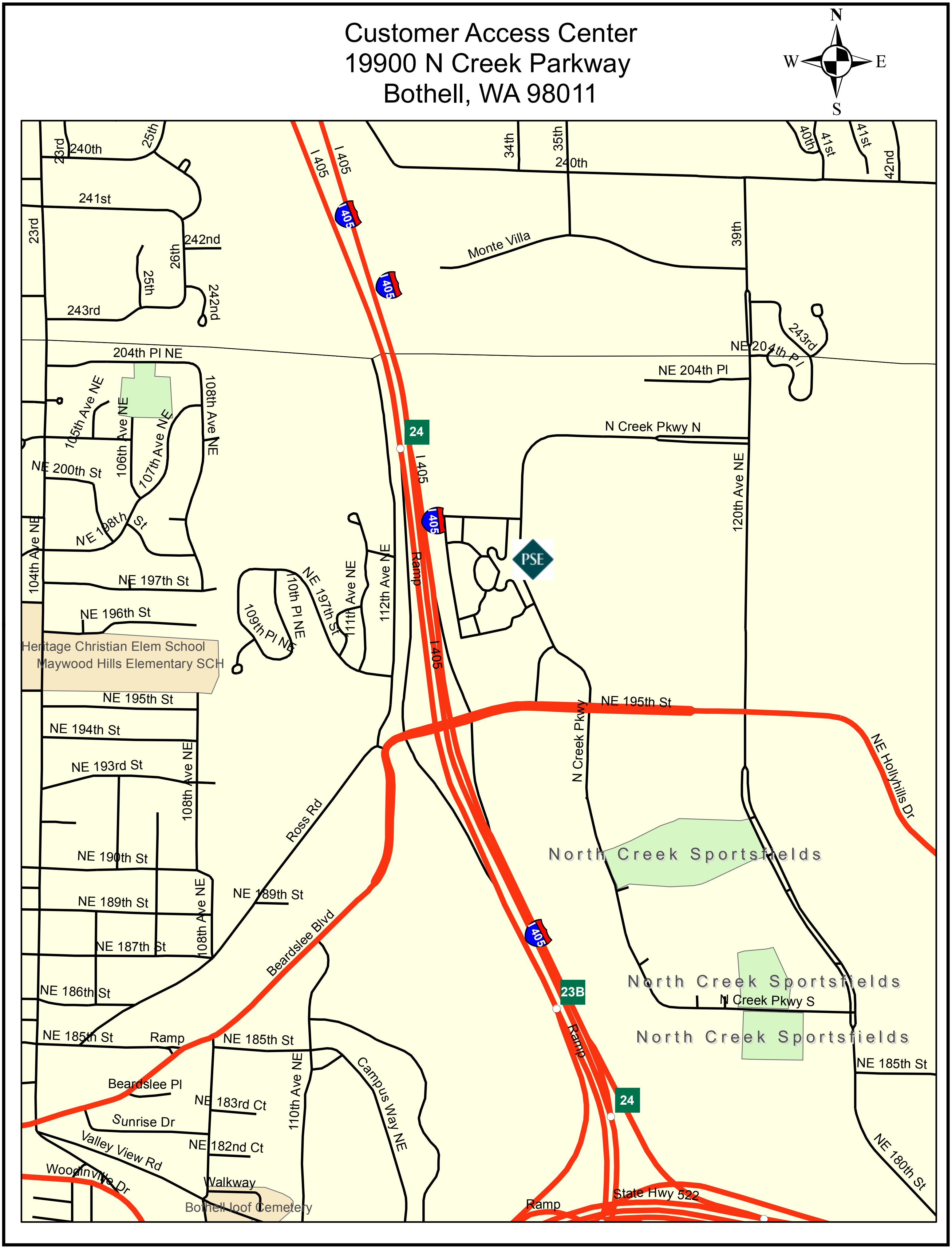


MID 9378002
230 kV Strut Insulator

The weathershed/sheath material is silicone rubber. Base mounting bolt holes consist of two 11/16-inch diameter holes, spaced 4 to 6 inches vertically.

NOTE: Grading rings are not provided with the insulators. The 230 kV strut insulator is to be used in conjunction with a suspension insulator that is equipped with a grading ring.

Customer Access Center
19900 N Creek Parkway
Bothell, WA 98011

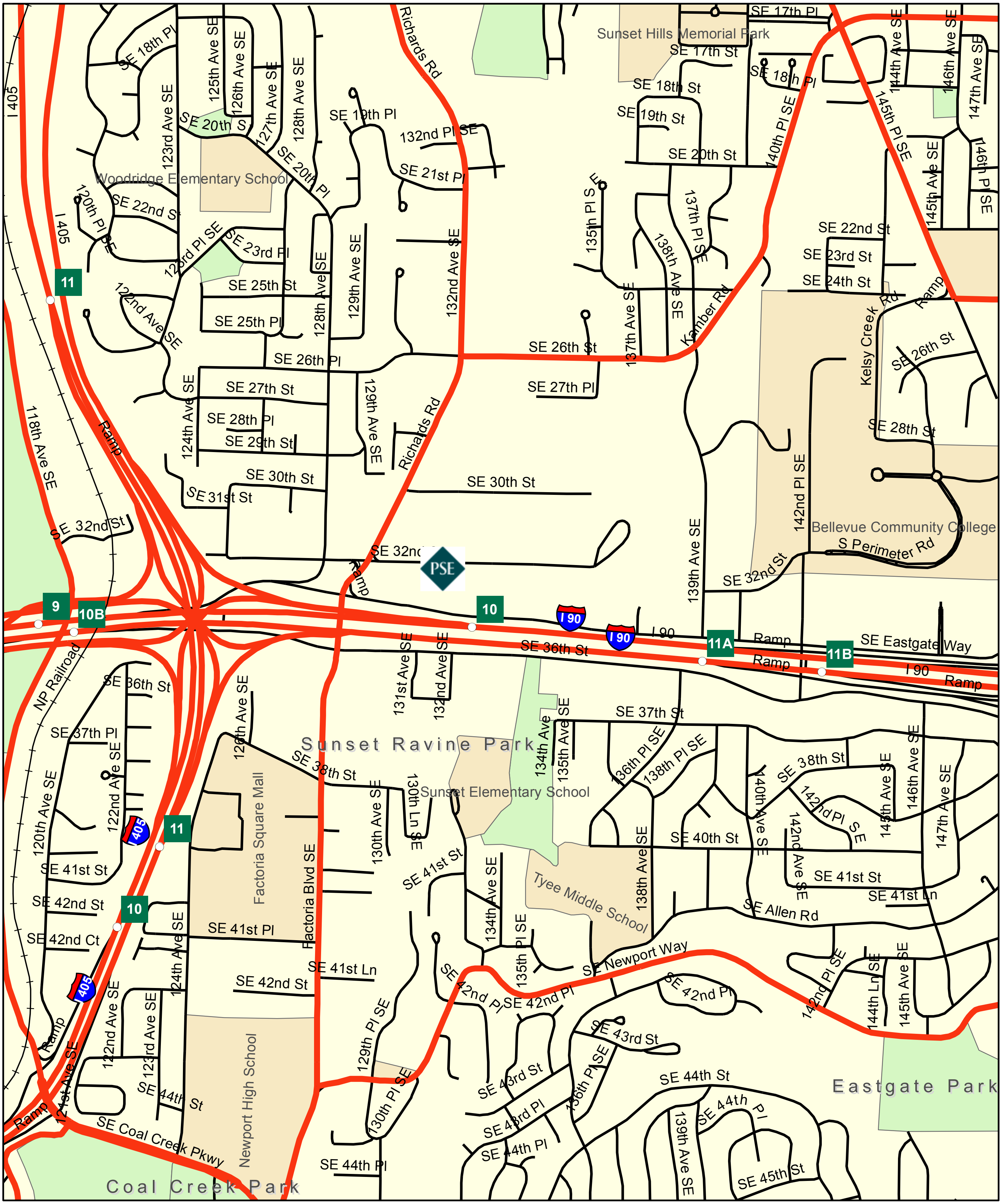


Notes:

Eastside System Operations
13635 NE 80th St.
Redmond, WA 98052

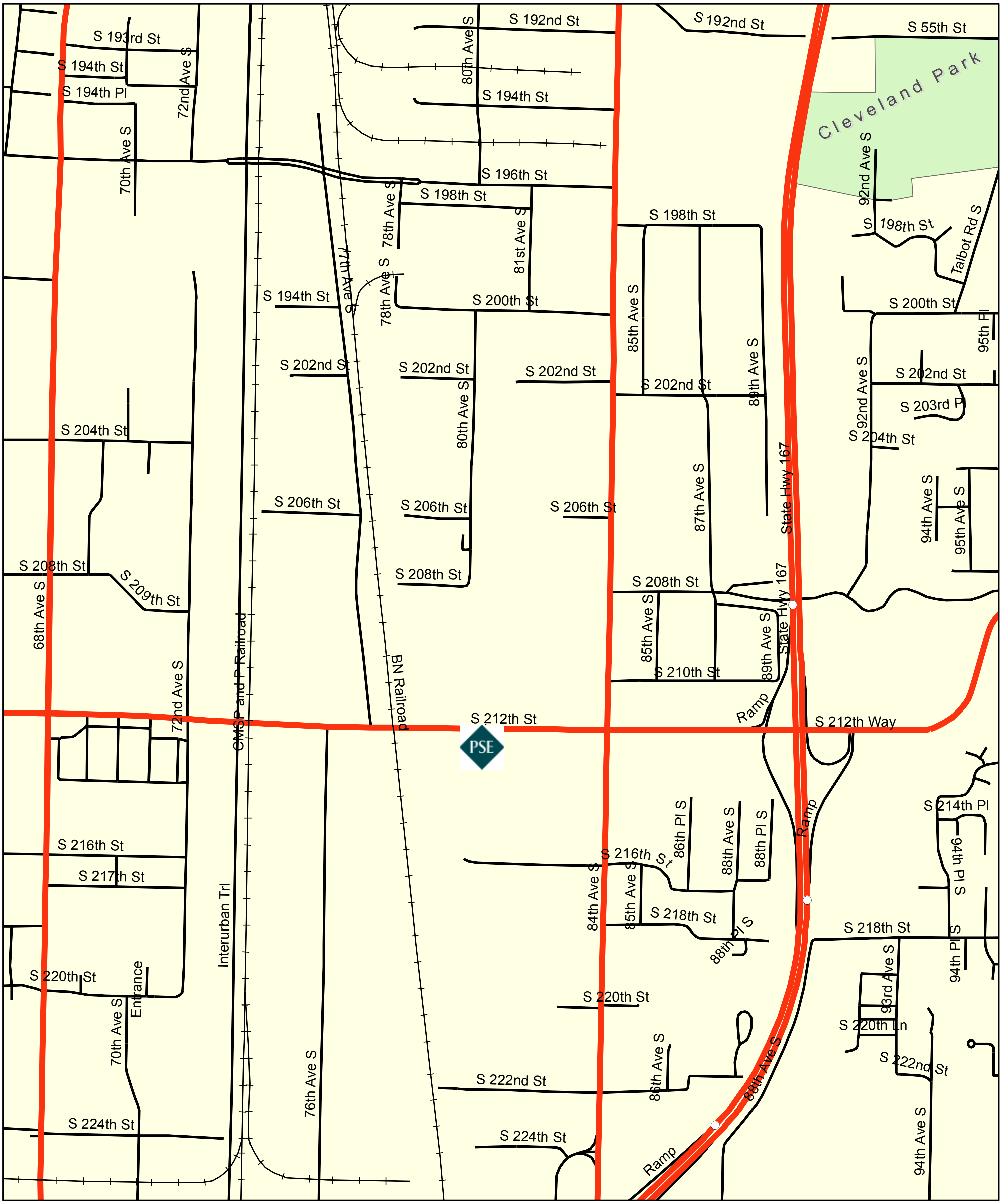
Notes:

Factoria Service Center
13230 SE 32nd St.
Bellevue, WA 98005



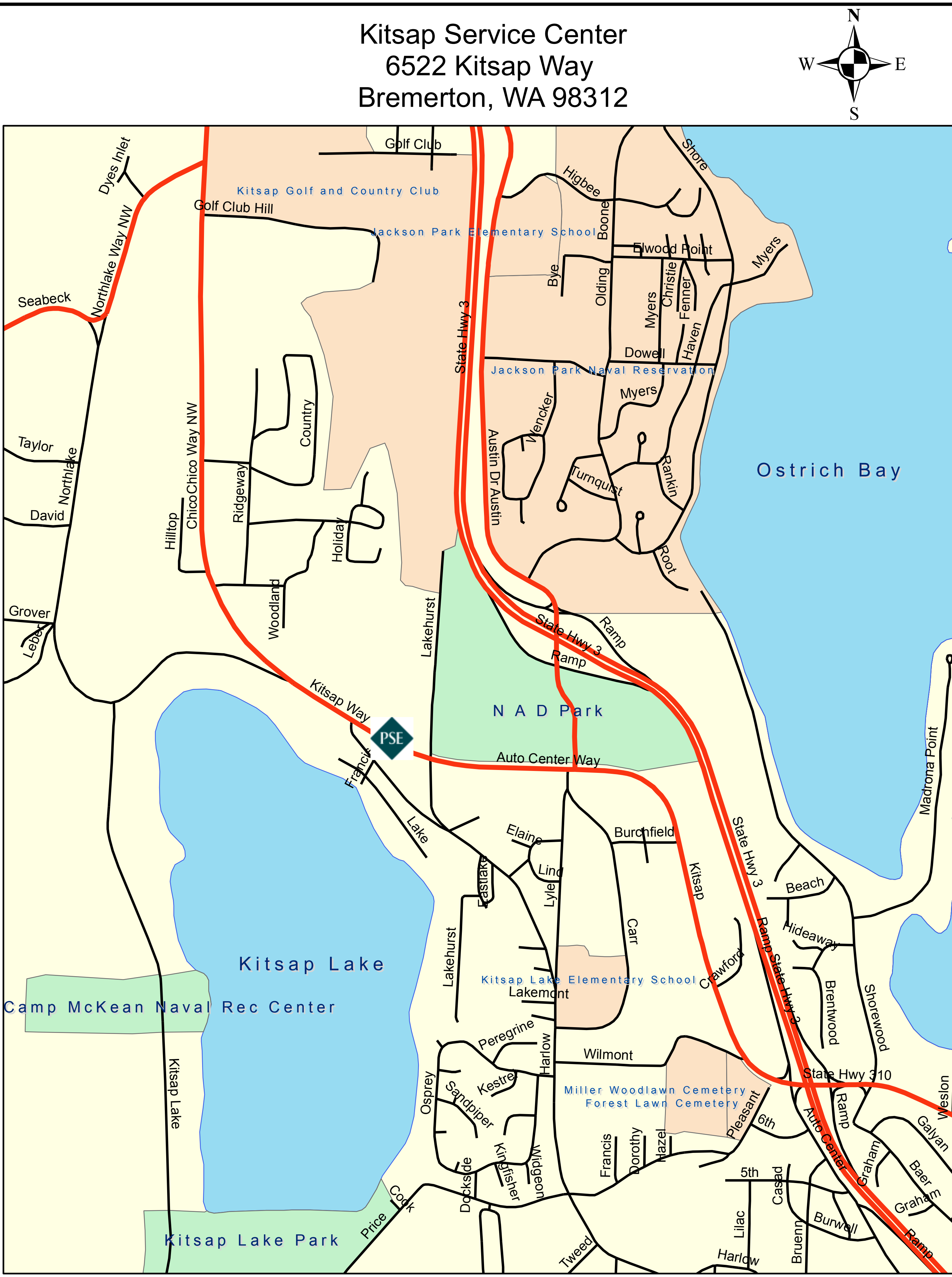
Notes:

Kent Fleet
8001 S 212th St.
Kent, WA 98032



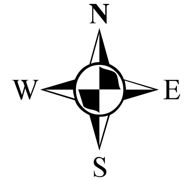
Notes:

Kitsap Service Center
6522 Kitsap Way
Bremerton, WA 98312



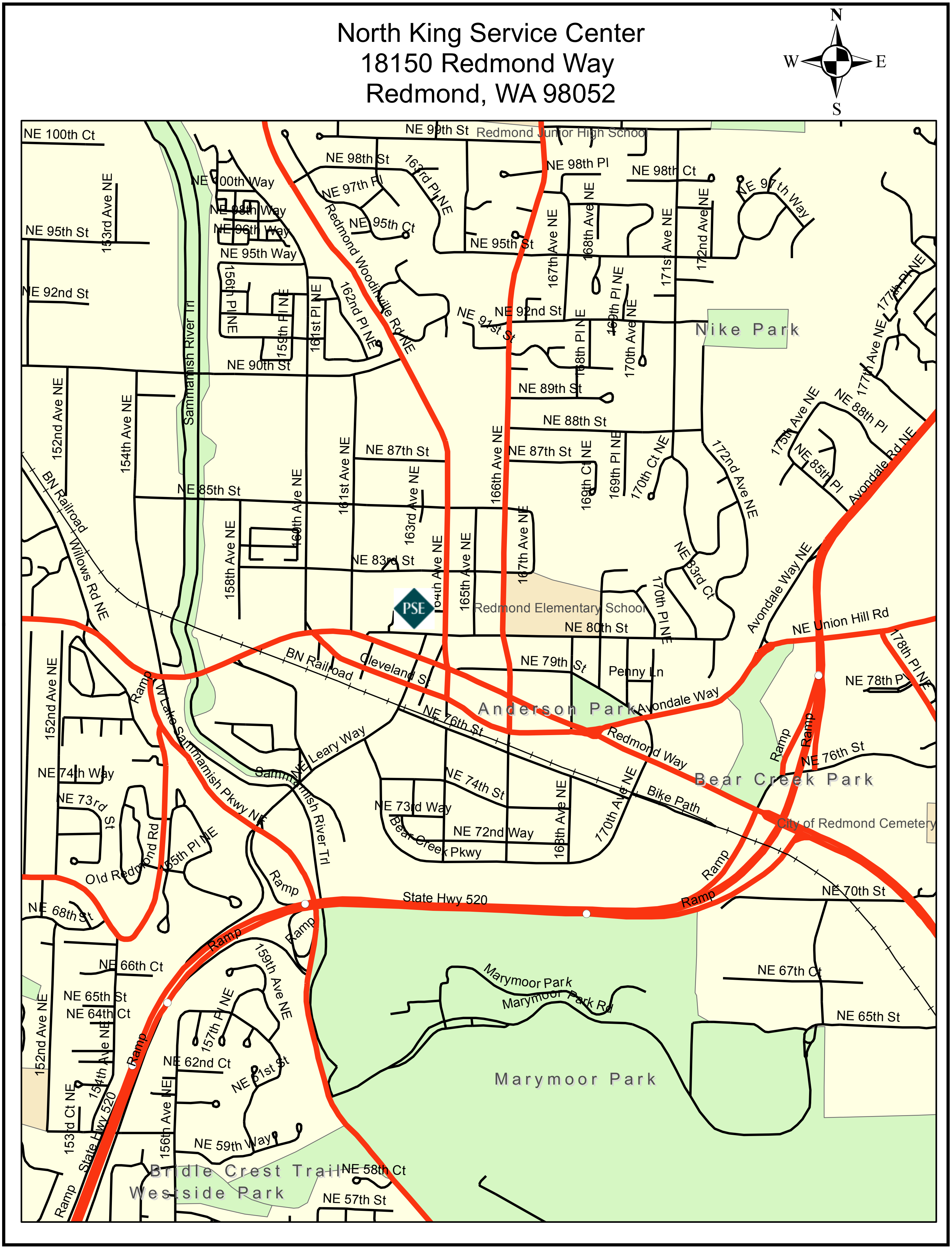
Notes:

Kittitas Service Center
8400 Thorp Hwy S
Thorp, WA 98946



Notes:

North King Service Center
18150 Redmond Way
Redmond, WA 98052



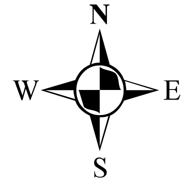
Notes:

Puyallup Service Center
5807 Milwaukee Ave E.
Puyallup, WA 98372

N
W
E
S

Notes:

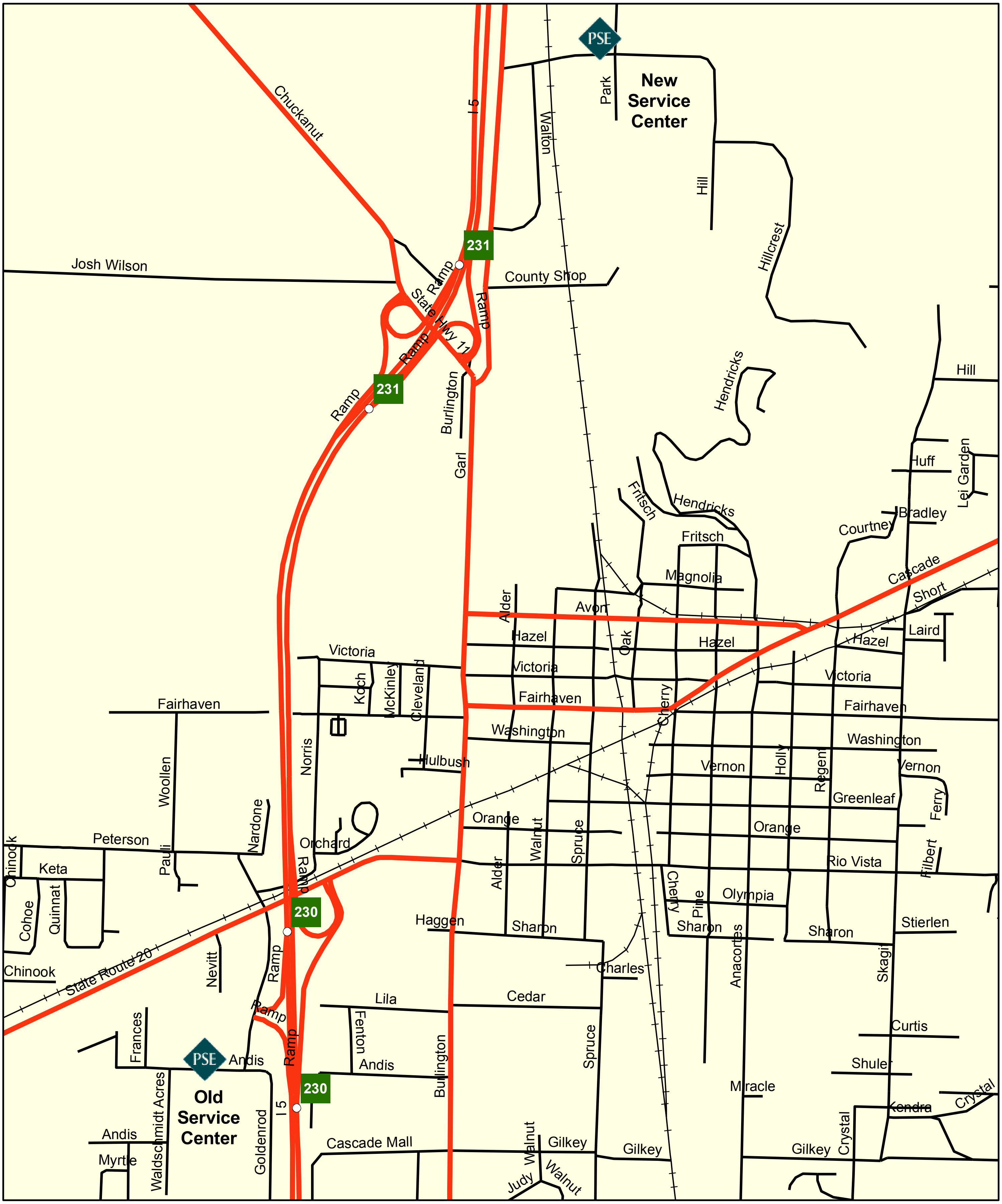
Shuffleton Office
1101 Lake Washington Blvd. N
Renton, WA 98056



Notes:

Old
Skagit Service Center
18601 Andis Rd.
Burlington, WA 98233

New
Skagit Service Center
1660 Park Lane
Burlington, WA 98233

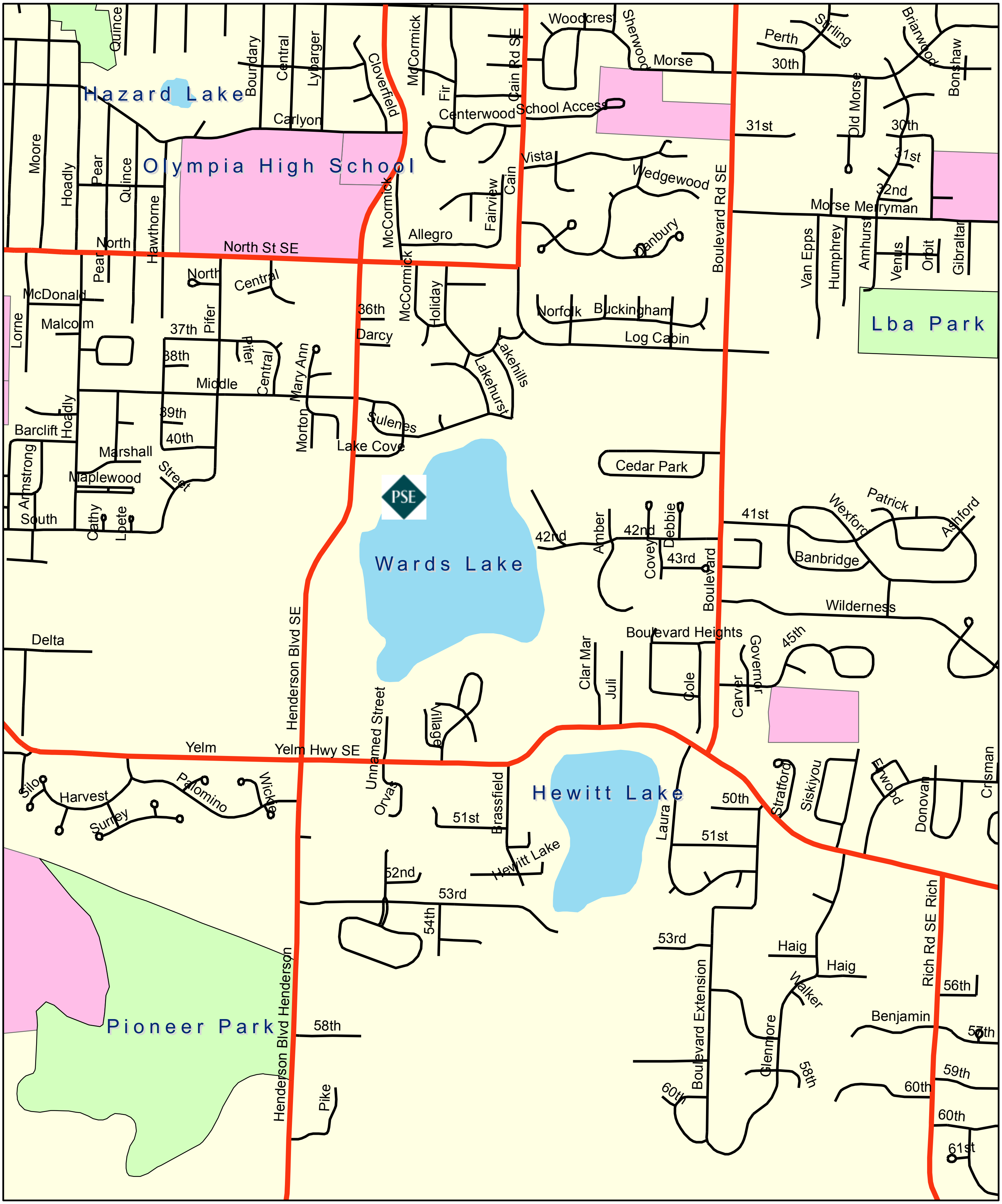


Notes:

South King Service Center
6905 S 228th St.
Kent, WA 98032

Notes:

Thurston Service Center
2711 Pacific Ave SE
Olympia, WA 98501



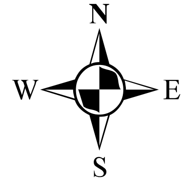
Notes:

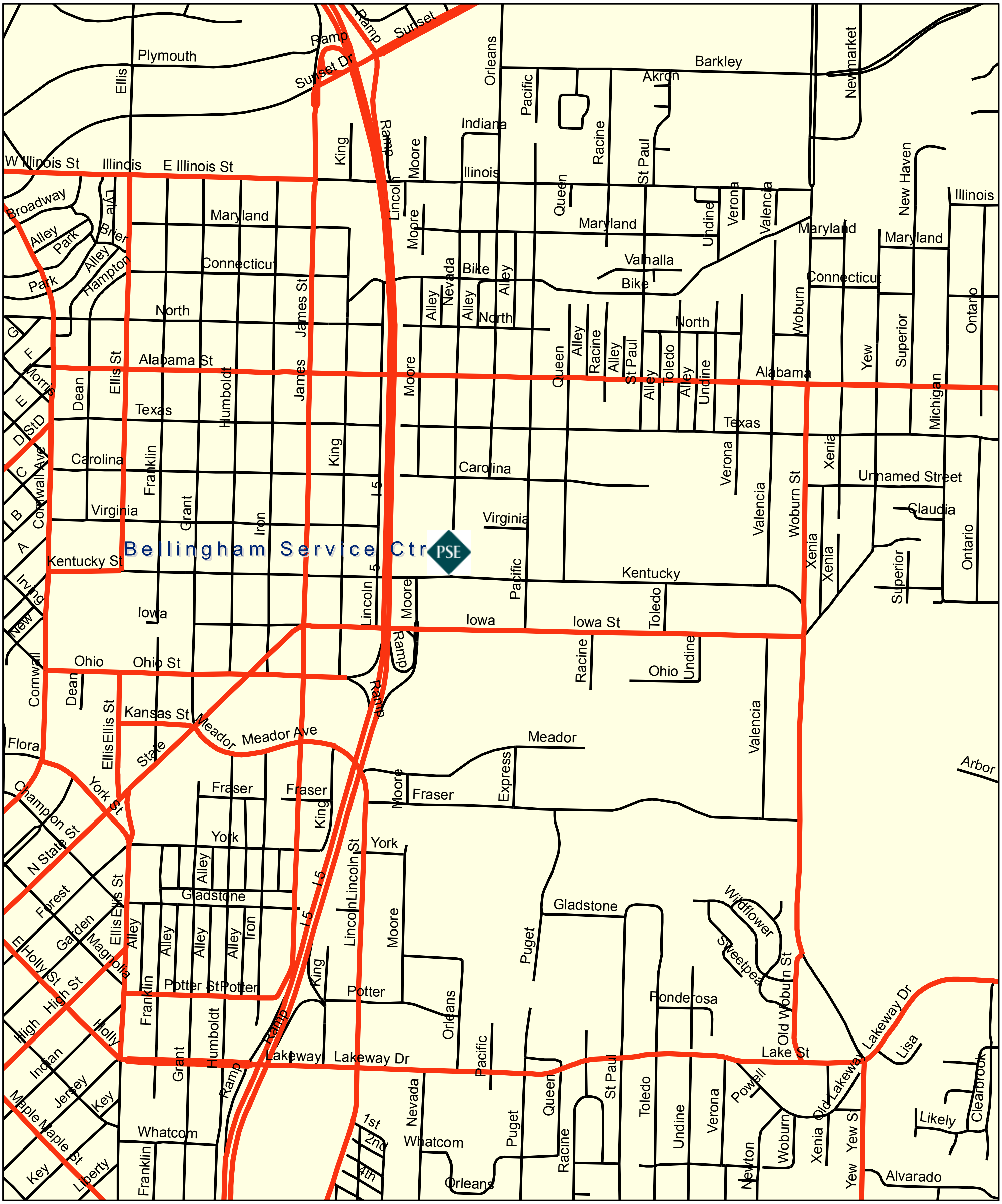
Vashon Service Center
18125 Vashon Highway SW
Vashon, WA 98070

N
W E
S

Notes:

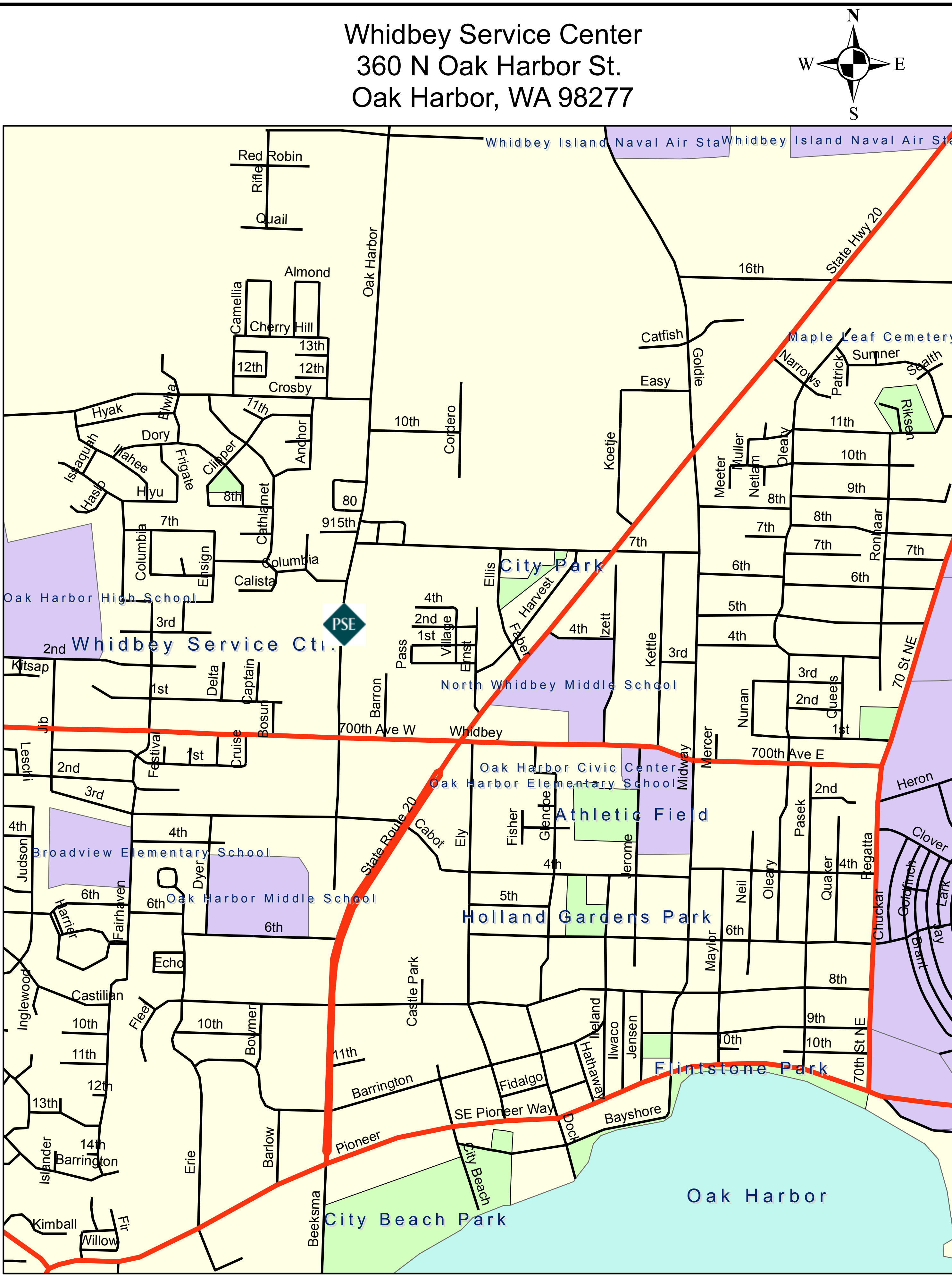
Whatcom Service Center
2131 Nevada St.
Bellingham, WA 98226





Notes:

Whidbey Service Center
360 N Oak Harbor St.
Oak Harbor, WA 98277



Notes:

EXHIBIT E

2007-2008

Corporate Emergency Response Plan

VOLUME 1 **2007-2008**

CORPORATE EMERGENCY RESPONSE PLAN





PSE PUGET SOUND ENERGY

The Energy To Do Great Things

Table of Contents

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SECTION 1 - OVERVIEW

Forward

Emergency Response Vision

A Consistent Response

This plan outlines Puget Sound Energy's (PSE's) philosophy and guidelines for responding to emergencies. PSE's emergency response plan emphasizes a single philosophy for responding to any type of emergency, regardless of cause or impact. Our procedures for response, restoration, and recovery are consistent throughout the company and should appear seamless to our customers and the general public.

PSE's Commitment

Increasingly, customers expect reliability to include absolute continuity of service and view any interruption as an emergency requiring our immediate response. All of our customers including the general public, cities, counties, state and commercial/industrial customers view electric and natural gas utilities as "lifelines" providing critical services.

While the safety of our employees and the public remains our first priority, we must ensure that:

- All Puget Sound Energy and service provider employees understand their roles in an emergency and are prepared to fulfill these assignments.
- Support systems and operation plans are in place to respond to all levels of emergencies.
- We provide outage, response, and restoration information meeting or exceeding customer expectations.

Guiding Principles

We will treat all customers, PSE and contract personnel with consideration and respect.

We will assess damage and relay information promptly. A high-level company impact assessment will be provided within 24 hours and accurate assessment and restoration estimates will be provided as each affected geographic area is analyzed.

We will work to ensure employee and public safety during emergency restoration efforts. We will follow all safety rules. We will treat sites that pose a risk to public safety (such as downed and energized conductors or broken gas pipe) as the highest priority, and secure the site before allocating resources to other service restoration efforts.

We will maintain environmental stewardship during major restoration efforts by complying with all environmental work practices and regulations.

Restoration Strategy

Significant variances in average outage duration should not be apparent among geographic areas. This applies to both isolated incidents and major events. We make every effort to cost-effectively re-deploy resources to meet this goal.

To reduce outage duration, we restore first, and then repair. Based on the conditions, damaged sections of the system may be de-energized, allowing service to be restored up to the point of damage, leaving the site safe until repairs can be completed.

PSE’s focus is to correct problems that can be fixed quickly, and to restore the greatest number of customers first.

If repairs must be delayed to a more appropriate time, we ensure that they are scheduled and completed in a timely manner. In significant and major events, we assess and schedule needed repair resources before we release crew resources.

We establish restoration priorities for unique customer groups for each geographic area. We are sensitive to individual customer situations throughout extended outages.

We implement and enforce standard policies and consistent operating practices company-wide.

Commitment to Reliability

Puget Sound Energy (PSE) has made a major commitment to its customers—to provide competitively priced products and superior services designed to meet their needs. Reliability is a key component of this commitment. It encompasses elements customers require from their energy provider.

PSE's response to an emergency is a critical component of the commitment, but it is also integrally linked with the other four components:

Service dependability

System dependability

Information to customers

Meeting customer expectations

This relationship is symbiotic in that no element of the reliability model can stand alone without carefully considering the potential impacts on the others.

Each component depends upon the others.

Purpose

How to Use This Plan

The Corporate Emergency Response Plan is intended to assist both PSE and service provider employees by establishing a comprehensive framework for responding to large-scale emergencies, regardless of their cause.

Use the information in this plan to prepare for any electric or natural gas system emergency. The plan helps ensure the safety of the public and employees *and* implements an effective restoration strategy that is consistent company-wide.

Plan Organization

The Corporate Emergency Response Plan is published in two volumes:

Volume 1: Corporate Emergency Response Plan 2007-2008

Section 1	Overview
Section 2	Hazards and Emergencies
Section 3	Key Information Systems
Section 4	Concept of Operations – Electric
Section 5	Concept of Operations – Gas
Section 6	Cold Weather Action Plan
Section 7	External Resources
Section 8	Energy Curtailment
Section 9	Appendices

Volume 2: Corporate Emergency Response Plan 2007-2008 – Additional Information.

Included in Volume 2 are detailed contractor resource lists, mutual assistance agreements, fleet and equipment resources, critical loads for restoration prioritization, Emergency Operations Center procedures, duty rosters, phone lists, etc.

NOTE: Volume 2 is *not* available for external distribution except as authorized by the Emergency Planning Manager.

Plan Availability

The Corporate Emergency Response Plan is available in all Puget Sound Energy departments.

The Plan is also available in Puget Sound Energy's service provider operating bases and offices. The Plan provides job requirements and responsibilities for PSE and service provider personnel to fulfill their roles in emergency response.

For additional copies, please contact Emergency Planning at (425) 462-3962 or 81-3962.

Your Comments Are Welcome

So that we may continually improve upon this plan, your comments are welcome. For more information, please contact:

Emergency Planning Manager, (425) 462-3962 or internally at 81-3962.

Scope of Plan

Emergency Response Plan

The Corporate Emergency Response Plan describes PSE's service territory, potential hazards, plan activation, emergency management organizational structure, role descriptions and response strategies.

This Plan does not provide process-specific procedures already detailed in other PSE documents; however, references to external material are provided.

External Plan References

Energy Emergency Plan – October, 2007

Gas Operating Standards – 2008

Gas Field Procedures – 2008

Cold Weather Action Plan – 2008

Gas Incident Command System – 2006

Rule 23 – Interruptible Sales and Transportation Service Priority

Energy Resources Emergency Action Plans

Sabotage Reporting – October 2007

Plan Activation

This plan is activated through routine evaluation of criteria unique to either gas or electric events. PSE operations staff vigilantly monitors system integrity, current and forecasted weather conditions, and current system impacts. When conditions are forecasted to deteriorate or, system events begin to escalate, duty managers are contacted and alerted to potential or actual plan activation. In turn, duty teams are alerted.

Electric Plan Activation Triggers

- Digressing or sustained poor weather conditions; or
- Transmission and/or distribution outages trending beyond nominal levels; or
- Increases in restoration workload may overwhelm available resources.

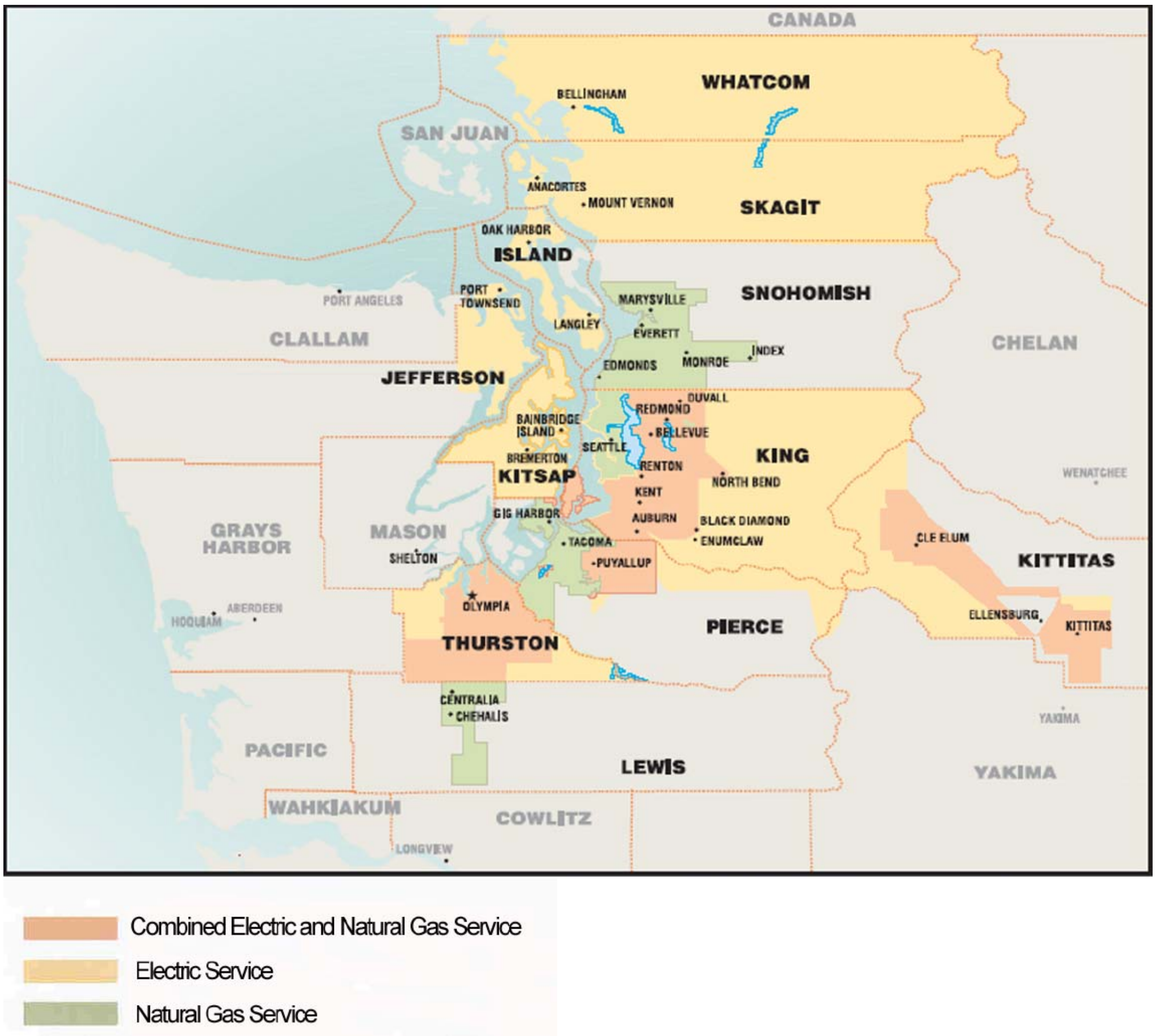
For additional information, see Plan Activation, page 57.

Gas Plan Activation Triggers

- Multiple or major gas main breaks affecting increasing numbers of customers; or
- Response capability stretched by multiple events, requiring prioritization; or
- Complex field situation, requiring support from off-site strategy team; or
- Supplier disruption.

Service Area and Organization

Service Area Map



Service Area Description

Puget Sound Energy divides its service territory into five geographic regions.

For electric service, the Northern region is comprised of Whatcom, Skagit and Island counties; King County is divided into North and South; the Southern region is comprised of Pierce and Thurston counties and PSE's Western region is comprised of Kitsap and Jefferson counties.

For gas service, the Northern region is North Seattle and Snohomish County; King County is divided into East, Central and South Central; the South region is comprised of Pierce, Thurston and Lewis counties.

PSE First Response

PSE Electric and Gas First Response provide immediate investigation of electric or gas emergencies (24/7) by utilizing an in-house staff of trained first responders. Electric First Response investigates electric outage reports and other non-outage emergencies such as low or downed wires and voltage problems. PSE Gas First Response investigates gas service and main breaks, gas odors and reports of poor gas pressure.

Calls received from customers and public service answering points (911 agencies) across PSE's service territory are taken as service orders, which are immediately dispatched to the appropriate first responder. Once on-site, the first responder provides an initial assessment including a public safety evaluation. Once site safety is confirmed, corrective action is initiated.

First responders are able to resolve or make safe most problems where damage to PSE's system is not severe.

Second Response

In situations where damage to PSE's distribution system is extensive, repair work is assigned to contracted service providers, [1]Quanta (Potelco) and Pilchuck. Service providers maintain crews, equipment and facilities within PSE's service area and are prepared to respond 24/7. Many PSE facilities are jointly staffed with both PSE and service provider personnel. Electric service providers repair or replace transmission or distribution components such as poles, cross arms, wire and other system hardware. Gas service providers repair or replace gas main, services or other system components.

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[1] Quanta Services, Inc. (Potelco in the Pacific Northwest) provides crews for both electric and construction work and new gas construction within the boundaries of PSE's electric service area. Pilchuck provides gas crews for construction in all other areas outside of PSE's electric service area, and gas system repair work company-wide.

Incident Reporting

Required Notifications

Certain incidents require both internal notifications as well as external reporting to governing agencies. External notifications are compliance-based and mandatory under State and Federal law and must be performed within specified time limits.

In addition to the notifications which follow, PSE is required to report to the WUTC any accident that results in death or serious injury to any person occurring in its plant or through contact with its facilities.

Notifying Departments These departments are responsible for performing these notifications:

Notification or Report	Responsible Department(s)
Gas incident notification and reporting	Gas Operations Safety Standards and Work Practices
Electrical incident notification and reporting	System Operations
Employee fatality or injury notification	Safety Standards and Work Practices
Any fatality or injury (non-employee)	Risk Management
Hazardous materials reporting	Environmental Services

Required Notifications - Gas

Incident	Notify	Within
Accidents, incidents and hazardous conditions which arise out of the Company's operations and result in any or all of the following: • A fatality or personal injury requiring (in-patient) hospitalization • Damage to the property of the Company and others of a combined total exceeding $50,000 (includes cost of gas lost); does not include automobile collisions and other equipment accidents not involving gas or gas handling equipment • The evacuation of a building or high occupancy structure or area, with the exception of self-evacuation of the structure or area • The unintentional ignition of gas • Unscheduled interruptions of service furnished by the Company to 25 or more distribution customers • Pipeline or system pressure exceeds the MAOP, plus ten percent • Pipeline system pressure exceeds the MOP, where the MOP is established through a pressure authorization from the WUTC • Is significant, in the judgment of the Company (even though it does not meet the requirements listed above) • The news media reporting the occurrence, even though it does not meet the criteria listed above	WUTC By telephone	2 hours

Required Notifications – Gas, Continued

Incident	Notify	Within
• Uncontrolled release of gas for more than two hours • Taking a high pressure supply, transmission pipeline or major distribution supply pipeline out of service • Pipeline or system operating at low pressure, drops below the safe operating conditions of attached appliances and gas equipment • Pipeline or system pressure exceeds the established MAOP **The WUTC reporting requirements *do not* apply to Jackson Prairie**	WUTC By telephone	24 hours
• A release of gas from a pipeline (or liquefied natural gas or gas from an LNG facility) **and** a death, or personal injury necessitating (in-patient) hospitalization • A release of gas from a pipeline (or liquefied natural gas or gas from an LNG facility) **and** estimated property damage, including the cost of gas lost, to the operator or others, or both, of $50,000 or more • An event that results in an emergency shutdown of an LNG facility • An event that is significant in the judgment of the operator even though it did not meet the requirements listed above. **The DOT reporting requirements *do* apply to Jackson Prairie as well as the rest of PSE**	DOT / National Response Center By telephone	2 hours

Required Notifications – Electric

Incident	Notify	Within
• Load shedding over 100 Mw of firm load for more than 15 minutes from a single incident. • Equipment failure resulting in loss of firm load over 300 Mw	Dept of Energy Emergency Ops Center By telephone & via Form DOE-417	1 hour
• 50,000 electric customers without power for 7 hours or longer	Dept of Energy Emergency Ops Center By telephone & via Form DOE-417	6 hours
• Rolling blackout activation	Reliability Coordinator via WECC net	Hourly updates required
• Sabotage Reporting	Law Enforcement and various entities (refer to Sabotage Reporting Procedures document)	Imme-diately

Documenting Fatalities

The Washington Department of Labor and Industries must be notified when two or more employees are (in-patient) hospitalized. It does not mean treated and released from the emergency room.

In addition to the steps for serious injuries, follow these steps to document fatalities:

NOTE: **All fatalities and potential fatalities shall be handled as follows:**

Step	Action

1	Notify these people immediately:
	• Safety Manager/Safety Department
	• PSE's officer team, including
	  ◦ Sr. Vice President, Operations
	  ◦ Vice President, Human Resources
	  ◦ Director, Gas Operations and Director, Electric Operations
	  ◦ Shop Steward, if applicable
	  ◦ Local Safety Committee Chairperson
	  ◦ Media Relations
	  ◦ Office of the General Counsel

2	The Safety Department should immediately send representatives to the scene to collect and preserve information, including photographs and witnesses' statements.
3	Conduct an immediate investigation under the direction of the injured person's supervisor, the Safety Department, top management officials, and the local Safety Committee chairperson.
4	Safety Manager/Safety Department: Report the accident to the nearest Washington State Department of Labor and Industries (Workplace Safety Inspections) office within 8 hours after the occurrence of the accident. The report shall relate the circumstances, the number of fatalities, and the number and extent of injuries. **NOTE:** Any equipment involved in an accident resulting in an immediate fatality is not to be moved until a WISHA representative investigates the accident and authorizes its removal. Equipment may be moved only if it is necessary to prevent further accidents or to remove the victim.
5	Human Resources, in coordination with local supervision, should contact Employee Assistance counselors for trauma debriefing.
6	The Workers' Compensation administrator, in coordination with the Safety Department, should assist with arranging medical consulting, as necessary.
7	The Executive Systems Integrity Committee (ESIC) shall review all fatal or catastrophic incidents.

SECTION 2 – HAZARDS and EMERGENCIES

Hazards in the Puget Sound Region

Hazards within Puget Sound Energy's service area with potential to have significant impact to electric and gas energy delivery systems, include:

Severe Weather

- High winds
- Snow / ice
- Extreme temperatures – winter cold / summer heat

Natural Events

- Earthquake
- Volcanic eruption / lahars

Human-Caused Events

- Terrorism
- Pandemics
- Third-party damage

Individually or collectively, these hazards have potential to cause widespread outages or may severely challenge available energy supplies.

PSE's response to damage caused by these hazards is essentially the same, regardless of the cause. Response to energy supply issues is documented in Section 8, Curtailment and Energy Supply Emergencies.

What is an Emergency?

PSE's Emergency Definition

PSE's definition of an electric emergency is directly related to the scope of restoration activity in any one geographic region or, activity company-wide when more than one region is affected. An electric emergency is defined as:

- 12 or more distribution circuits impacted in any one region and escalating; or,
- 30 or more distribution circuits affected company-wide, and / or

Poor weather conditions with high winds, snow or ice predicted; earthquake or other natural hazard conditions.

PSE's definition of a gas emergency is also related to the scope of activity; however, the activity is generally focused on safe control of escaping gas and preventing a loss of gas service to customers. PSE defines a gas emergency as:

- Main or service breaks, outages or other events that may stretch internal response capability, or
- Complex field situation requiring support from an off-site strategy team, or
- Response requiring large numbers of employees from multiple departments, or
- Gas send-out at or above 125 MMCF with significant system constraints predicted, or
- Supplier system/facility conditions with potential for adverse impact to PSE's gas system, or
- Incident resulting in a high pressure main being removed from service

External Emergency Definitions

There are certain operating definitions of an emergency with which PSE must comply, or must be used to determine the level of response.

PSE's emergency response complies with the following codes and regulations:

- WAC 296-45-035 for the electrical system, "…an unforeseen occurrence endangering life, limb, or property."
- WAC 480-93-180 for natural gas, ensures the company is "… in compliance with the provisions of the federal Natural Gas Pipeline Safety Act, 49 CFR part 192."
- WAC 194-22 for electric load curtailment.
- Federal and state statutes requiring PSE to develop and implement safety policies and procedures.

PSE customers want and expect reliable electric and natural gas service delivery. If service is interrupted, for whatever reason, customers could potentially view this as an emergency.

Event Levels

PSE utilizes event levels to characterize the overall impact of an event. Event severity escalates from level 0 to level 3, each having a corresponding response level.

With an advance weather forecast, an event level is predicted based upon forecast models. The predicted event level suggests the level of advance mobilization required.

As soon as field conditions permit, early visual damage assessment is utilized to help affirm or adjust the event level and the corresponding level of response.

With unpredicted events, early visual damage assessment is utilized to determine the event level and corresponding level of response.

Departments having emergency response roles, such as Operations, Purchasing, Materials Management, Customer Services and Corporate Communications use event levels as triggers for internal processes.

The following table illustrates PSE's Event Levels:

EVENT LEVELS

Levels	Electric Criteria	Gas Criteria	Level of Response	Operations Actions
Level 0 **Normal**	Nominal conditions across system.	Nominal conditions across system.	Normal daily response activity.	Normal operations.
Level 1 **Regional**	Event localized to individual geographic areas; resources within region adequate for response.	Localized event managed with PSE regional resources.	Operations base(s) open; coordination with system operations or gas control. Gas Planning Strategy Center open for gas emergencies.	Emergency Operations Center (EOC) not opened. Internal resources utilized. Some use of employees with Emergency Response (ER) assignments.
Level 2 **Significant**	Multiple regions affected; requires resources from other PSE regions and/or outside PSE service territory.	Multiple PSE regions affected; requires resources to be allocated to other PSE regions.	EOC open; multiple operating bases open and local area coordination may be activated. Employees with emergency response assignments mobilized.	EOC opened. Additional contractor resources needed; some from bordering states. Moderate to extensive use of employees with ER assignments. Windshield assessment utilized. Complete assessment within 24-36 hrs. Local area coordination possible.
Level 3 **Major**	Most or all regions affected; maximum level response required; need extensive resources from outside service territory.	Most or all PSE regions affected; may request operator qualified resources from outside PSE.	EOC open; most or all operating bases open; external logistics support may be employed; full corporate response to support restoration efforts.	EOC opened. Resources obtained from outside of region. Full utilization of employees with ER assignments. Local area coordination implemented. Windshield assessment utilized; complete assessment within 48-72 hours.

Public Safety

As the event begins, PSE's first priority is to dispatch servicemen (first responders) to make damaged areas safe for the public as well as responding employees of PSE and its' service providers. This means responding quickly to reports of gas odors, damaged gas facilities, downed wire and/or poles blocking access to main roadways. If wire is energized and down, it is de-energized and then physically removed from access roads.

Restoration Priorities

PSE will restore facilities so that the greatest numbers of customers are back in service in the least amount of time.

Repairs may be minimized with permanent repairs made later. These temporary repairs are recorded for follow-up.

Generally, energy distribution facilities are restored in this order:

- Transmission
- Distribution
- Distribution
- Individual services

Within this context, PSE considers municipal requests for priority restoration of:

- Hospitals, fire departments, police stations
- Emergency shelters
- Water treatment plants, sewage pumping stations
- Buildings that house large numbers of people
- Facilities from which people cannot be easily relocated (nursing homes), etc.

Preparedness

Planning

To maintain operational readiness to respond to any emergency, operations personnel ensure that planning, plan updates, assignment of personnel, training, exercises and plan modification take place at least annually. Operations staff ensures appropriate roles are defined for field, Gas Planning and Strategy Center (GPSC), Emergency Operations Center (EOC) functions, and renew the organization chart and staff assignments annually.

In addition, activities designed to educate the public and acquaint them with preparedness measures are coordinated through Operations in the planning/preparedness phase. Other departments (such as Government and Community Relations, Corporate Communications, etc.) execute these activities.

The Emergency Planning Manager facilitates these activities, and recruits expertise from other departments to assist when necessary.

Emergency Response Assignments

Employees of PSE and its' service providers who do not regularly perform field operations and/or customer service duties will assist in certain emergency response efforts.

To assign and qualify personnel for temporary job duties, job descriptions listing skills and requirements to perform the work have been created for some functions.

All employees who do not normally perform emergency response efforts will be trained for emergency assignments. Employees may have a primary assignment and back-up assignment. Specific training requirements are listed by job and will be offered, as required, to ensure employees are qualified for their emergency response assignment.

As part of their job assignments, all employees of Puget Sound Energy, Quanta and Pilchuck are expected to respond to emergency situations when called. Employees will be trained and fully qualified to perform their pre-assigned emergency response functions. Employees will be asked to *only* perform jobs for which they are qualified.

Training and Orientation

Specific training or safety orientations are provided each year for:

- EOC Manager
- 911 Call-Taker
- CLX Specialist
- EMS Analyst
- Contract Crew Coordinator
- Damage Assessor
- Lodging Coordinator
- Driver

To communicate plan changes and procedural changes, annual storm planning orientations are provided to operations management staff, EOC teams, storm board staff and other non-operations departments.

Exercises

PSE conducts exercises annually, at a minimum. Significant plan and procedural changes are incorporated into the exercises each year. Exercises may take the form of a full-scale event or tabletop discussions. In full-scale exercises, activity is simulated using test instances of PSE's various information systems, which allows participants to view, strategize, and report on overall response efforts. Event participants are provided an opportunity to exercise their respective emergency response roles and overall plan knowledge. A post-exercise debriefing is held to determine the effectiveness of the plan and to identify adjustments that may need to be made.

In tabletop exercises, facilitated discussions are used to explore plausible scenarios at a high level. Problems and their potential solutions are reviewed for incorporation into future emergency response plans.

Post-Event Debriefings

Following any emergency activation, a debriefing meeting with the emergency response team will be held to discuss what worked well and what didn't, focusing on how PSE and its' service providers could improve response efforts.

Regional event – Regional Operations Managers or Supervisors will schedule the meeting.

Significant and major events (EOC opened) – Emergency Planning Manager will schedule the meeting.

Event participants may include:

- First Response and Operations Management
- System Control and Protection
- Gas System Operations
- EOC or GPSC Personnel
- Service Provider Management
- System Control staff (Load Office, on-duty System Operations Supervisor)
- Emergency Planning Manager
- Customer Service Management
- Safety
- Standards and Work Practices
- Materials Management
- Corporate Communications

Topics discussed may include:

- Public and employee safety
- Damage assessment
- Personnel and equipment mobilization
- Restoration updates for customer feedback
- Internal and external communications
- Materials
- Restoration and repair

Recommendations for improvement are incorporated into processes, plan documents and training.

Communications

Personnel in all PSE and service provider facilities must be able to communicate with the EOC, System Control and other department personnel during emergencies. Information flow (whether voice, radio, or data) is critical to our ability to advise customers of the status of particular situations, and to provide meaningful restoration estimates.

If telecommunications fail at any time during an emergency, the Information Technology/telecommunications department will assist in their restoration.

Back-Up Communication

Company Radios, GETS / WPS, Amateur Radio

Management responsible for emergency response may be provided with Company radios for back-up communications. Radios will be used for two-way communications and to deploy resources when landlines and cellular phones are not operational (e.g., due to earthquake).

Select employees are enrolled in Government Emergency Telecommunication Service (GETS) and Wireless Priority Service (WPS). In the event the public telephone network is intact, however overwhelmed by a high volume of calls, GETS / WPS users will be able to make urgent calls with priority routing through the public telephone network.

Additionally, licensed amateur radio operators, members of PSE’s Amateur Radio Emergency Services (ARES) team will be able to provide site-to-site radio traffic using amateur (HAM) radio. This includes amateur radio communications with other PSE facilities as well as external agencies, such as City, County or State EOC(s).

Emergency Operations Center (EOC)

EOC's Role and Expectations

The role of the EOC is to coordinate the work of others, so that PSE can respond effectively to a significant emergency.

Emergency management activities fall into four (4) phases:

1. Event planning
2. Coordinating communication
3. Coordinating response
4. Coordinating recovery

Individuals assigned to the EOC are responsible for some element of the activities performed in each of the five phases, which are outlined below.

Planning

Operations Emergency Planning ensures that planning, plan updates, personnel assignments, training, exercises and plan modifications take place at least annually. Operations staff ensures appropriate roles are defined for the EOC, GPSC and Operating Base organizations, and updates organization charts and staff assignments annually. In addition, Emergency Planning collaborates with Corporate Communications on activities designed to educate the public and acquaint them with emergency preparedness measures. When planning is complete, departments (such as Operations, Corporate Communications, etc.) are responsible for executing these activities.

Coordinating Communication

The EOC acts as a clearinghouse for information.

As information becomes available from a variety of sources, it is channeled to the EOC so that the situation may be evaluated and reported back throughout the company on a consistent and regular schedule. This helps provide accurate, detailed messages to customers, media, governmental EOCs, and employees working on restoration.

Coordinating Response

The matrix below details who makes the calls for assessment and restoration resources:

If EOC is . . .	Who . . .	Calls (no order implied) . . .
Not open	On-duty System Operations Supervisor (EOC duty manager may assist)	Service Provider crews within the region; Service Provider crews from adjacent areas.
Open	EOC Duty Manager and Service Provider Duty Manager	Any available Service Provider crews Regional, out-of state, and foreign contractors Mutual Assistance Utilities Damage assessors Contract crew coordinators Others, as required

Who Does What?

The matrix below details who is responsible for what types of actions.

This group...	Is responsible to...
Operations	Makes a request to EOC and/or GPSC for manpower and equipment. Advises the EOC and/or GPSC of crew availability and re-assigns or releases crew, as appropriate.
EOC	Acquires specifically requested labor pool and equipment and dispatches resources to fill operating base's request. Notifies operating bases when crew(s) dispatched, what equipment and personnel were included, and the estimated time of arrival. If restoration estimates are very different between areas, work to move resources between areas to balance restoration time frames.
Operations	Prepare work assignment and required support prior to crew arrival. Record time of arrival and crew composition. Notify EOC and/or GPSC when crew is ready to be released.

Coordinating Recovery

Using PSE's restoration prioritization guidelines, the EOC, System Control, GPSC, First Response and Service Provider management will work together to coordinate system recovery and restore service to customers.

Event Strategy and Coordinating Response

The EOC and GPSC personnel are not responsible for the response itself, but for coordinating response efforts corporate-wide, including acquisition of additional resources. The EOC and GPSC staff coordinate the use of resources over the entire affected area(s). The EOC personnel typically:

- Coordinate opening and closing of the EOC with the on-duty System Operations Supervisor or GPSC. (The GPSC staff determines the appropriate time to close operations if they are activated without the EOC.)
- Coordinate the level of required response with the given emergency situation.
- Contact and deploy employees who are not routinely involved in system damage assessment and restoration.
- Contact local, regional, out-of-state, and foreign contractors to assist in system restoration efforts. Contact other utilities for mutual assistance in system restoration efforts.
- Contact State/Federal emergency operations or other governmental personnel to obtain access for out-of-the-region resources (such as contacting U.S. Customs and Immigration so that crews from British Columbia or other Canadian provinces may be processed quickly).
- Act as a central clearinghouse for information on PSE's emergency response.

Processing 911 Calls

The EOC is made aware of potential region-wide hazards and coordinates the dissemination of that information as required to operations personnel. PSE's first priority is to make the damaged areas safe for the public and employees. The EOC manager ensures adequate 911 Call-takers are in place to respond to an increased volume of urgent calls from local 911 call centers.

This facilitates quick response to reports of downed wire, arcing/sparking wire, blocked right-of-way, broken and blowing gas pipe, burning gas, odor calls, etc.

Resource Acquisition

The EOC or GPSC are responsible to obtain additional resources as may be required by operating bases. The EOC has available lists of PSE employees, external contractors and mutual assistance agreements.

Back-up Control Center

Puget Sound Energy has implemented a back-up control center that provides critical operating capabilities should one (or more) primary control functions become impaired or, the primary location uninhabitable. The back-up control center provides a secondary operating location for the Electric Load Office, Electric System Operations, the Emergency Operations Center/GPSC, Gas Control, and Gas Operations Dispatch.

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SECTION 3 – KEY INFORMATION SYSTEMS

- ConsumerLinX Outage Management (CLX)
- Distribution Data Display (DDD)
- Energy Management System (EMS)
- Distribution Management System (DMS)
- Gas SCADA (Supervisory Control and Data Acquisition)
- SynerGEE System (Gas Load Modeling)
- Mobile Workforce Management (P-CAD)

ConsumerLinX Outage Response (CLX)

What is CLX Outage Management?
ConsumerLinX (CLX) is an on-line system that tracks outage calls from electric customers. It provides a link between employees who receive customer outage calls and employees who are responsible to restore electric service. Access to CLX is required to access CLX Outage Management. CLX Outage Management supplies outage call locations to DDD (Distribution Data Display), where the information is displayed geographically to visually determine the size of a particular outage. CLX is also used to input gas emergency calls received by the CAC.
Who Uses CLX Outage Management?
CLX is used by • Customer Access Center • System Control • EOC/Operating Bases • Operations personnel
Updating CLX Outage Management
Because it is our most important source for electric outage information, timely updates to CLX are critical to PSE's success at restoring electrical service. PSE requires an update as soon as information is available from the field and should include: • Cause description and estimated number of customers out • Investigator dispatched date/time • Damage assessment teams dispatched • Crew dispatched date/time • Estimated restoration date/time

If CLX Outage Management Fails	
If the CLX Outage Management system fails for any reason, Customer Access Center representatives (the primary receiver of customer calls in an outage situation) will take the following actions:	
Step	**Action**
1	For gas emergencies – Customer Access Center notifies Gas Dispatch.
2	Manually complete individual "emergency" and/or outage reports on the appropriate forms via fax or e-mail.
3	Contact Gas Dispatch and/or Electric System Control to alert them of the initial emergency report.
4	Fax or e-mail the emergency information to gas dispatch and/or system control.
5	If applicable, activate an IVRU broadcast message and Qwest Intercept Message to alert customers of the outage areas, and to direct gas emergency calls to the back-up emergency telephone number. NOTE: Customer Access Center Point Desk staff will load updates manually to both broadcast messages as information is received from Operations.

Distribution Data Display (DDD)

What is DDD?
DDD is a PC application that displays geographical data about PSE's electric system. This display includes: • Sites • Poles • Transformers • Switches • Streetlights • Substations During major storms the DDD system is a useful tool for the operating bases to pinpoint smaller outages on circuits, as well as for subdividing outages into smaller sub-circuit outages. It estimates the number of customers out, and provides better information to the customers within the sub-circuit area. During major storms, transmission lines are often down, with entire substations off-line and many full-circuit outages occur. When an entire circuit is out, DDD is not helpful for evaluating where the outage is. However, when damage assessors come back with reports of damage, DDD is useful in creating sub-circuit outages. Without DDD, individual outages cannot be subdivided in CLX. DDD will also display the location of customers who have called to report outages. It is used for outage management and by the engineering departments for various studies. DDD pulls

information from SAP by station and circuit, and it pulls active outage calls from CLX for the same station and circuit. It then displays outage calls on top of the circuit information. This provides a pin map with red dots where the outage calls are coming in. This can be very helpful in finding where an outage is on a circuit. A polygon can also be created around the area of the outage and sent back to CLX creating a sub-circuit outage for the area affected by the outage.
Who Uses DDD?
DDD interacts with SAP that supplies the data about PSE's electric system and CLX that supplies data about customer outage calls. DDD is used by the following staff: • EOC • System Control • First Response • Field Operations
If the DDD System Fails
Not all operating bases have DDD, and if it is down during a storm, CLX can still be used alone. Some accuracy in customer information will be lost. Availability of DDD is not critical during a storm.

Energy Management System (EMS)

What is EMS?
The EMS system displays key electric system information, such as: • Line power flows • Switch and breaker status • Transformer load • Bus voltage • Generator output status Also, the EMS performs the Automatic Generator Control (AGC) function. Personnel in the Load Office have remote control over transmission breakers, some transmission switches, some distribution breakers, remotely operated generation, and some substation voltage control functions through EMS. The power system information on EMS is displayed in diagram and table format, and is available in a read-only status in many operating bases and the EOC.

Who Uses EMS?

In an electric system emergency, EMS users are:

- Storm bases
- Load Office
- Energy Production and Storage
- EOC

If the EMS System Fails

If EMS fails, power dispatchers in System Control contact the EMS duty supervisor immediately. Operations revert to manual because remote switching and computerized system status is not available when EMS is down. Energy Production and Storage initiates their internal procedures.

EOC should also call the EMS duty supervisor; however, repairs to “read only” EMS systems will be done only after the real-time, interactive portions have been restored.

Distribution Management System (DMS)

What is DMS?

The DMS system displays key electric distribution system information, such as:

- Substation and feeder configuration
- Switch numbers and information
- Distribution system status
- Distribution system activity log of switching, clearances, and operations

The electric system information on DMS is displayed in diagram and table format.

DMS automatically transmits key outage information to CLX. When an area operating base is open, this automatic link is disabled to prevent inadvertent overwriting of comments in CLX.

Who Uses DMS?

System Operations

If the DMS Fails

If DMS fails, System Control contacts the EMS duty supervisor immediately. System information and activity must be logged manually until DMS is restored.

Gas Supervisory Control and Data Acquisition (SCADA)

What is Gas SCADA?

A system of computers, communications devices and paths, transducers and remote computers used for monitoring flows, pressures, temperatures, odorizers, alarms and operation of pressure controlling devices.

Who Uses Gas SCADA?

- Gas Controllers
- System Control and Protection
- Total Energy Systems Planning (TESP)
- Gas First Response

If Gas SCADA Fails

Contact the IT department SCADA tech on duty immediately for problem analysis, as most components in the system have a back-up. If the SCADA system will be out of service for an extended period of time, the Gas Controller must dispatch Pressure Control Technicians, Instrumentation Technicians, First Responders and others to key points in the system to monitor and report via radio or mobile phone. System information and activity must be logged and calculated manually until Gas SCADA is restored.

Gas Controllers can initiate or complete minor repairs, restoration and system restarts.

SynerGEE System (Gas Load Modeling)

What is SynerGEE?

The SynerGEE workstation is a computer-modeling tool that simulates a natural gas piping network. By using load data gathered from meter reads and piping information from construction crews, the model can be used to solve pressure and flow problems. SynerGEE can also identify possible problems resulting from third-party damage to the gas distribution system.

Who Uses SynerGEE?

Total Energy Systems Planning (TESP) maintains the SynerGEE system for the entire gas distribution system. Piping data is entered daily, and load information is downloaded monthly. This information helps TESP know where to expect inadequate pressure during times of increased usage.

If the SynerGEE System Fails

If SynerGEE is not operable, TESP uses a series of field chart recorders to get an approximate idea of system pressures, and can therefore develop an approximation of system flows. Gas First Response and System Control and Protection personnel also help gather system data.

Mobile Workforce Management (P-CAD)

What is Mobile Workforce Management?

Mobile workforce management (MWF) is an automated service order and dispatching tool that notifies field personnel of service work in real time, through a wireless device. Field personnel are able to receive orders and related instructions and, subsequently provide wireless status updates on work completed.

MWF allows dispatchers to assign work to, and "track" the location of field personnel having mobile data terminals.

MWF will not be used for large outage events.

Who Uses Mobile Workforce?

Mobile Workforce is used by

- Gas service technicians and electric servicemen.
- Gas and electric dispatchers
- Field service supervisors
- Customer Service Representatives

What if Mobile Workforce Management Fails?

- If MWF is down and CLX still remains available, service order status will be handled manually through CLX. If both CLX and MWF are unavailable, assignment of service orders and tracking of field resources will be done manually.

SECTION 4 – CONCEPT OF OPERATIONS – ELECTRIC

Emergency Information Sources

How PSE is Notified

The Customer Access Center receives trouble calls from all types of customers. Electric dispatch and System Operations receive trouble calls directly from area 911 centers. Information is most commonly received via normal phone line and in major events 911 centers may combine several reports and fax to system operations.

Information may also come directly to individual employees as part of their normal work through their interactions with work contacts, or through relationships in the community. Employees of PSE and/or its' service providers who are likely to receive word of service problems include the following:

- Electric/Gas First Response personnel
- Operations Dispatch
- Major and Key Account Executives
- Government and Community Relations Managers
- Project Managers

Media reports and reporters' inquiries may also call PSE's attention to major service disruption problems. In addition, System Control personnel detect problems in the course of monitoring automated electric and gas transmission and distribution systems.

Outage Reports and Service Orders

Trouble calls received via the Customer Access Center are entered into ConsumerLinX (CLX) and result in service orders/outage reports being queued and printed to the appropriate first response dispatcher.

Electric trouble orders are directed to electric dispatchers during normal working hours and system operators after-hours. Service orders are routed to a specific dispatcher or operator based upon the geographic region the address is located within.

When operating bases are activated for electric restoration, outage reports and emergency service orders are systematically redirected to local bases to facilitate analysis and oversight of storm restoration work.

Customer Communications

Getting Information to Customers

PSE's Corporate Communications department works 24/7 with Customer Service and Operations Management, the EOC and the on-duty System Operations Supervisors to develop customer messaging for use on the pse.com web, media press releases and to assist the Customer Access Center with recorded messages for customers. They also collaborate with the company's Local Government and Community Relations Managers to develop regional messaging appropriate for the areas impacted by damage.

PSE staffs EOC liaisons at the State and County EOC's on request by those agencies. The PSE EOC liaison works at the local level to provide emergency event response and recovery status reports through these government entities.

Information flows to individual customers through the CLX system and representatives staffing the Customer Access Center. To provide customers with current information, the CLX system is kept updated with estimated restoration times and outage status. The Customer Access Center may also call customers back to ensure their service is restored. The company may also initiate automated calls to large geographic areas with event status information or to request customers to conserve use of natural gas or electricity for a period of time.

Electric Emergency Organizational Structure

PSE's emergency response plan is scalable, allowing response efforts to be matched to the event. In regional events, where damage may be limited in scope and contained within a single geographic region, a single operating base's storm board may be activated.

In larger events, where damage affects more than one geographic region or, where damage is extensive, multiple operating bases and the EOC may be opened.

The following pages detail the organizational structures used in responding to electric emergency.

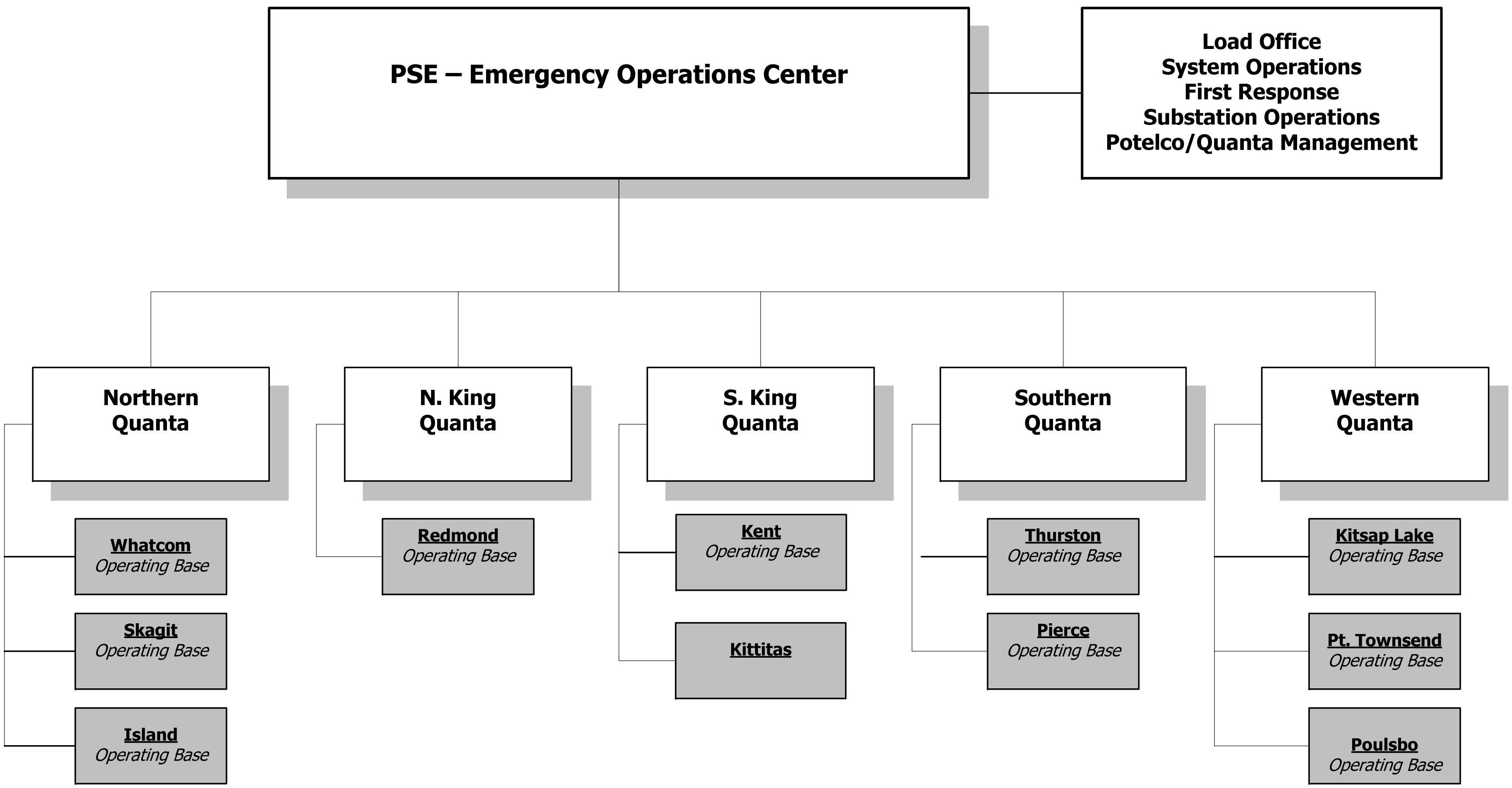
Electric Emergency Event Organization

The following organization chart reflects reporting relationships for Electric Emergency Response efforts:

Electric Emergency Organization 2007-2008

2007-08 ELECTRIC EMERGENCY EVENT MANAGEMENT ORGANIZATION

REVISED 09/2007

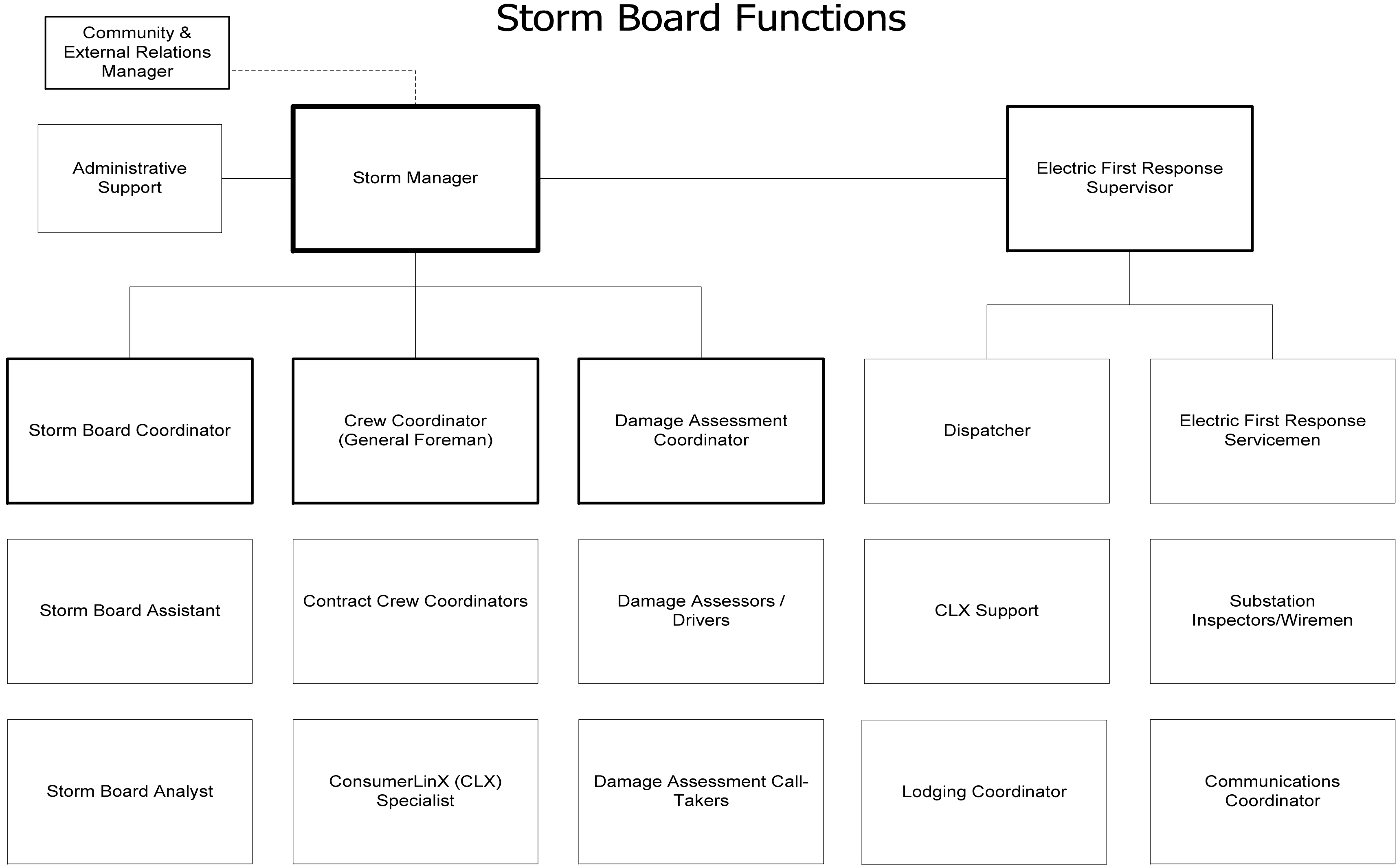


Storm Board Organizational Structure

The following organization chart reflects reporting relationships for the Storm Board efforts:

Quanta Operating Base – Storm Board Functions

Quanta Operating Base
Storm Board Functions

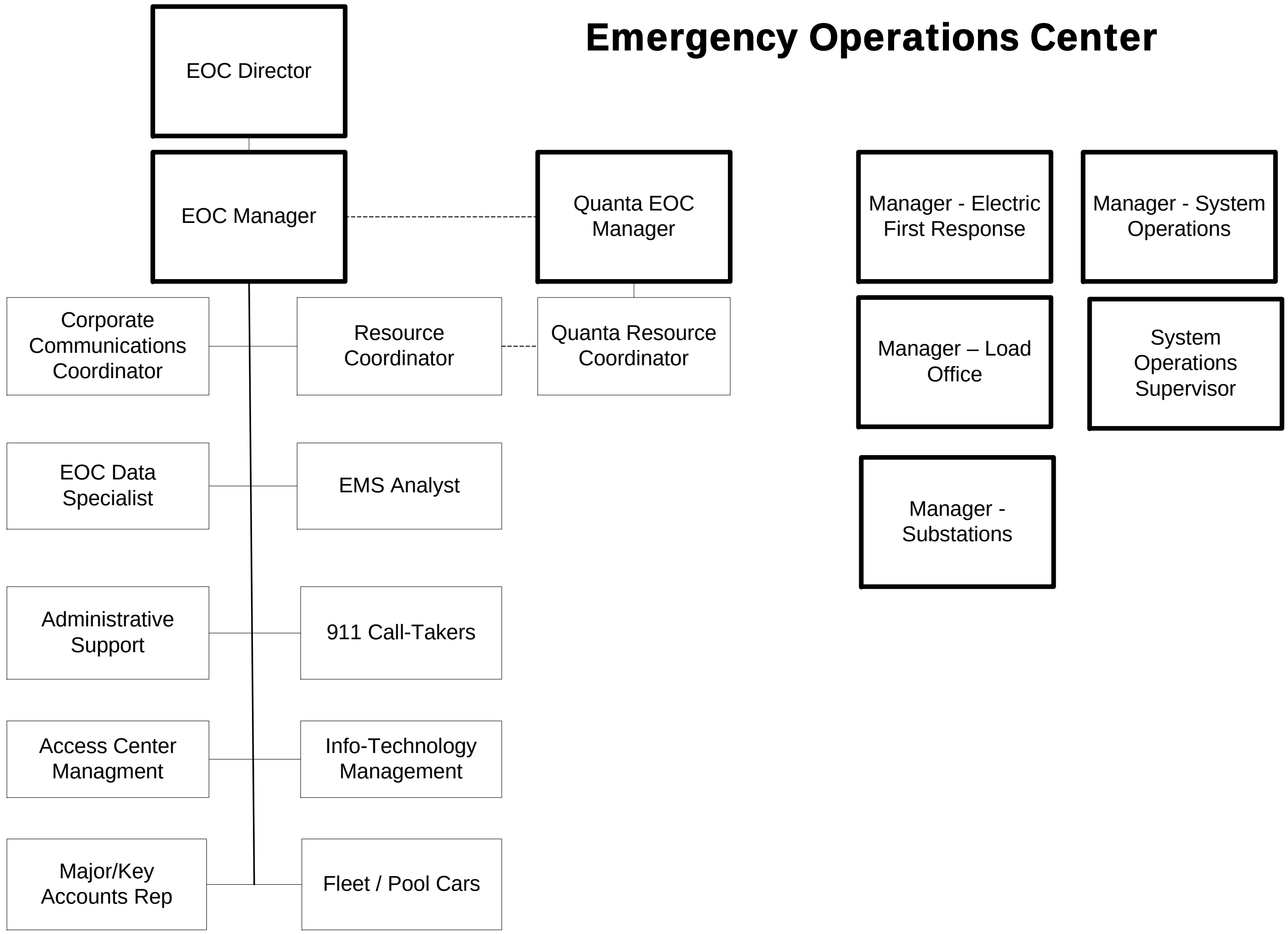


EOC Organization Structure

The following organization chart reflects functions within the EOC:

Emergency Operations Center – Functions

Emergency Operations Center



Emergency Response Roles – Electric

This section describes the positions and job duties at the EOC and positions at the Quanta Operating Bases for electric emergency response. The Corporate EOC is headquartered at Eastside Operations – Redmond. Operating bases are located regionally and managed by Quanta.

EOC Roles

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Corporate EOC	EOC Director	The EOC director provides Corporate (strategic) oversight and financial authority to response efforts. Once the EOC is opened, the Director becomes the information focal point for the executive management team and may respond to media inquiries about emergency response activities as needed by Corporate Communications.	Emergency Response Overview; EOC Orientation
	EOC Manager	Coordinates opening of the EOC and determines level of response required for each emergency. Coordinates with Quanta EOC Duty Manager to obtain resources needed for restoration. Balances available resources against system damage and realigns overall efforts when estimated restoration times are significantly skewed between regions. Oversees overall event reporting and ensures periodic detailed reports are issued.	Emergency Response Overview; EOC Orientation

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Corporate EOC	Quanta EOC Duty Manager	Works with Puget Sound Energy EOC Director and Manager to acquire resources needed for emergency events. Ensures Quanta resources for crews, damage assessors, CLX data entry personnel, etc. are trained and qualified for emergency response functions. Coordinates movement of Quanta regional resources and out-of-region crews that may be required for major events including equipment, fleet, travel and accommodations. Requests additional resources from PSE EOC Manager as required to augment operating base personnel; e.g., damage assessors, crew coordinators, drivers, CLX information specialists, crew supervisors, etc.	Emergency Response Overview; EOC Orientation
	EOC Communications Coordinator	Coordinates with EOC Director and Manager to ensure timely and accurate communications with the media. Coordinates messaging with Operations, Customer Access Center and regional Communications Coordinators to ensure that restoration information is consistent across all communications channels.	Emergency Response Overview
Corporate EOC	EMS Analyst	Assesses system damage through electronic sensors located in substations and along major transmission lines (SCADA, EMS, DMS). Focuses primarily on providing outage information at the substation and transmission line level. Ensures transmission, substation status information is communicated to EOC and to storm board personnel at the Operating Bases.	Emergency Response Overview EMS Training

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Corporate EOC	I/T Manager	Responsible to provide resolution oversight to reported hardware, application, network or key interface issues, including telecommunication failures. Coordinates with PSE's helpdesk, network, application and desktop personnel to assure failures are quickly resolved or appropriately escalated, ensuring mission-critical technology tools are returned to service a soon as may be practicable.	Emergency Response Overview
Corporate EOC	Manager, Electric First Response	Works with Quanta EOC Duty Manager, PSE EOC Manager, On-duty System Operations Supervisor and PSE First Response Supervisors to provide support in assessment and restoration. Coordinates company-wide first-response resource allocation including decisions to move first response servicemen out of area, etc.	Emergency Response Overview
Corporate EOC	Resource Coordinator	Assists in the allocation and retention of resources as required by field operations including assessors, additional crews, flaggers, etc. Works with Quanta EOC Duty Manager to ensure adequate crew availability and may call out and assign non-Quanta, foreign and/or mutual assistance utility crews. May also call out specialty contractors (flagging, tree removal, helicopter and environmental, etc.) as required by PSE and Quanta for service restoration. Make arrangements for border crossings, ferry travel, and emergency road openings as required. Tracks foreign crews as they change locations within PSE's service territory.	Emergency Response Overview
Corporate EOC	Data Specialist	An outage data expert. Familiar with CLX and AMR outage tools. Tracks progression of outages and customer calls; archives history of event at regular intervals. May also perform DDD analysis.	Emergency Response Overview; EOC Orientation

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Corporate EOC	Administrative Support	Provides general administrative assistance including answering phones and preparing forms and documents. Maintains all event records and documents for entire event. May assist resource coordinators in calling PSE employees for emergency response assignment. Obtains and organizes periodic detailed reports for each impacted area and collates into regular updates for internal audiences such as, customer service, Corporate Communications and, external audiences such as, State / County / City EOC's	Emergency Response Overview; EOC Orientation
Corporate EOC	911 Call Taker	Answers emergency calls from 911 agencies, police, etc. reporting downed wire, fires, and blocked right-of-ways. Enters reported information into CLX, ensuring priority outage reports are sent to Quanta operating bases.	Emergency Response Overview; 911 Call Taker Training
Corporate EOC	On-Duty System Operations Supervisor	A regularly staffed PSE position responsible for initiating the emergency response. Monitors weather and regularly communicates with PSE staff and Quanta field operations. Notifies Quanta management and EOC duty management to activate emergency response plans. Monitors emergency event escalation, restoration efforts and overall recovery of the electric system. Declares event level.	Emergency Response Overview
County EOC	County EOC Liaison	Represent PSE at assigned county EOC. Serve as liaison and focal point for communication between County EOC staff and PSE. Provide routine updates to County EOC staff on impacts to PSE's energy distribution system(s) and current restoration timelines. Identify key coordination issues between PSE and County and facilitate discussions to resolve. Collaborate with County officials on community messaging. Coordinate with County staff to obtain additional resources as required.	Emergency Response Overview

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
State EOC	State EOC Liaison	Represent PSE at State of WA EOC at Camp Murray. Serve as liaison and focal point for communication between State of WA Emergency Management Division (EMD) staff and PSE. Provide updates to EMD staff on impacts to PSE’s energy distribution system(s) and current restoration timelines. Identify key coordination issues between PSE and State of WA and facilitate discussions to resolve. Coordinate temporary rule exemptions where restrictive regulation may slow response efforts. Coordinate with EMD staff to obtain additional resources, as required.	Emergency Response Overview

Operating Base Roles
These functions are performed by Quanta and/or PSE employees:

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Quanta Operating Base	Operating Base Manager	Directs or manages regional storm operations, emergency response assignments, assessment, and restoration. Primary contact person with EOC, System Operations, Substations, Load Office, and Customer Access Center. Assesses needs for additional resources, coordinating with EOC for external resources and assistance as required. Coordinates with the Damage Assessment Coordinator, Storm Board Coordinator and EOC to prioritize restoration activities.	Emergency Response Overview; CLX Outage Management
Quanta Operating Base	First Response Supervisor	Provides support for Quanta Operating Base Manager as required. Supervises and monitors local first responders (servicemen) and electric dispatchers to ensure adequate response. Reassigns first responders for service restoration and damage assessment as appropriate. Provides EOC with information as requested. May act as Operating Base Manager for shift coverage as require	Emergency Response Overview; CLX Outage Management
Quanta Operating Base	Storm Board Coordinator	Reports to the Quanta Operating Base Manager. Analyzes outages and tracks needed repairs and location of assigned resources. Receives information from servicemen, CLX, 911 call-takers, damage assessors and others in field. Packages damage information and assigns work packages by area for efficient restoration. Reviews / prioritizes response to emergencies reported via 911 agencies.	Emergency Response Overview; CLX Outage Management

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Quanta Operating Base	Storm Board Analyst	Assists the Storm Board Coordinator to coordinate and prioritize restoration and identify circuits. Provides DDD and EMS expertise as required; e.g., sub-circuiting outages for CLX. Assists CLX data entry process to ensure customer system updated accurately and timely. Works with Damage Assessment Coordinator to determine damage assessment needs and coordinate Damage Assessors for the designated area.	Emergency Response Overview; CLX Outage Management; DDD and or EMS
Quanta Operating Base	Storm Board Assistant	Provides support to Storm Board Coordinator. Reviews available outage information and records emergency. Assists in prioritizing work and communicates assignments to Damage Assessors, electric Dispatcher and Contract Crew Coordinator. Updates Storm Board and ensures CLX reflects current status. Assists with analysis and prioritizing of emergencies reported via 911 agencies.	Emergency Response Overview; CLX Outage Management

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Quanta Operating Base	Damage Assessment Coordinator	Reports to the Quanta Operating Base Manager. Oversees and coordinates the damage assessment and restoration prioritization for the operating base. Manages and assigns qualified personnel to damage assessment duties. Ensures the Storm Boards are updated and that CLX updates are consistent, timely and accurate. Assists in prioritizing restoration efforts. Communicates status and locations of assessment teams within the area. Coordinates with Operating Base Manager and Storm Board Coordinator to prioritize restoration activities	Emergency Response Overview; CLX Outage Management; Damage Assessment Training
Quanta Operating Base	Damage Assessor	Reports to the Damage Assessment Coordinator. Assesses system damage in designated areas. Records damage and material needs and relays the information to the Damage Assessment Coordinator.	Emergency Response Overview; Damage Assessor Training

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Quanta Operating Base	Crew Coordinator (General Foreman)	Reports to the Quanta Operating Base Manager. Oversees the line crew restoration effort throughout the event. Ensures field resources are deployed efficiently for safe and timely restoration. Assigns line crews to prioritized repair jobs.	Emergency Response Overview; Contract Crew Coordinator Training
Quanta Operating Base	Dispatcher	Reports to PSE First Response Supervisor. Dispatches PSE Servicemen and Quanta two-person emergency crews to 911 calls, critical switching, patrolling, and secondary service restoration. May work with some autonomy early in event and later works in close coordination with storm board staff as event escalates and overall event management shifts to the Storm Board Coordinator.	Emergency Response Overview; CLX Outage Management
Quanta Operating Base	CLX Specialist	Updates CLX Outage Management information system regularly throughout the emergency to ensure prompt, accurate information to the Customer Access Center and EOC.	Emergency Response Overview; CLX Outage Management
Quanta Operating Base	Local Area Coordination Site Manager	Assigned to a geographic subset of the operating base region. Manages resources at Local Area Coordination Site including site staffing, crews, damage assessors, materials and equipment. Manages all restoration activity (damage assessment, restoration prioritization and related crew assignments) to restore extensively damaged areas. Assigned areas may be defined electrically, such as all circuits from specific substations or geographically using landmark boundaries. Communicates with the Operating Base and the EOC.	Emergency Response Overview; Contract Crew Coordinator Training

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Quanta Operating Base	Contract Crew Coordinator	Reports to the Crew Coordinator (GF). Leads crews to damaged areas and works ahead of crews to see that effective restoration methods are being followed, material and other needs are met. Ensures foreign crew personnel are informed of required safety, construction and switching practice information.	Emergency Response Overview; Contract Crew Coordinator Training
Quanta Operating Base	Community & External Relations Manager	Works closely with local operating base management throughout the emergency to ensure that critical customer loads (e.g., healthcare, area shelter locations, etc.) are appropriately identified and prioritized for restoration. Monitors outages impacting Major and Business Accounts as well as specific customer groups or areas. Coordinates with the Media Representative in the EOC (or, corporate communications when the EOC is not open) to ensure that notifications and updates provided locally are consistent with messages issued through Corporate Communications and the Customer Access Center. In coordination with Corporate Communication, provides information to local media, municipalities, and county emergency response departments (when the EOC is not open) on damage assessment and outage restoration efforts.	Emergency Response Overview

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Quanta Operating Base	Communica-tions Lead	Responds to specific customer inquiries from major account or key business customers (e.g., schools, healthcare facilities, grocery store chains, etc.). Works with the Major Account Representative(s) in the EOC to coordinate major and key customer response. Takes escalated call inquires from the EOC, Customer Access Center, or the Executive Office providing information for specific customers. Researches status of outage and restoration efforts for specific customers as required. Works closely with Storm Board Coordinator to gather information.	Emergency Response Overview
Quanta Operating Base	Lodging Coordinator	Provides lodging coordination for regional operating bases. Manages local lodging arrangements (assign/track personnel and their lodging assignments) to ensure adequate bed capacity for foreign crews and other operating/storm base personnel. Coordinates with hotel staff to arrange, add/reduce hotel rooms over the course of the emergency event. Provides regular reports on current lodging arrangements and utilization.	Emergency Response Overview; Lodging Coordinator Training
Quanta Operating Base	Driver	Performs driving duty for Damage Assessors or Contract Crew Coordinators. Safely operates vehicle while Damage Assessor visually assesses and records circuit damage	Driver Training
Quanta Operating Base	Make Safe Team Member	Dispatched to locations where primary wire is reported to be down. Ensures site and public safety until qualified electrical workers are on-scene.	Emergency Response Overview; Make Safe Training

Plan Activation

Puget Sound Energy (PSE) and Quanta Services, Inc. (Quanta) – PSE's electric service provider – follow the activation plan detailed below.

As inclement weather conditions arise and/or notice issued of pending disaster, the on-duty PSE System Operations Supervisor monitors company readiness to respond to outages.

The on-duty System Operations Supervisor and Quanta (Service Provider) Emergency Operations Center (EOC) Manager, if available, will review all potential emergency outage events.

Upon review, they will jointly determine if an emergency/storm event has occurred based on, among other things, the following:

- Weather conditions
- Size of the event (number of outage events; circuits impacted)
- Number of crew jobs pending
- Length of restoration time remaining
- An overflow of work at system dispatch

The on-duty System Supervisor in consult with electric first response, PSE and Quanta operations management, load office, or other will declare an event level to be "Regional", "Significant" or "Major".

PSE's on-duty System Operations Supervisor is responsible for evaluating and declaring that an emergency/storm event has occurred.

At the time of such declaration, Quanta will immediately assume responsibility for dispatching Quanta crew resources and opening their operations bases.

The PSE on-duty System Operations Supervisor may contact the Quanta Duty Supervisors in affected areas directly, if the event only requires the opening of one to three operating bases. If it is a widespread emergency event, the Quanta EOC Center Manager shall make notifications to their operations management and request bases are opened.

Activating the EOC

The PSE on-duty System Operations Supervisor will activate the Emergency Operations Center (EOC) by contacting the on-duty EOC Manager, as well as notifying the following:

- EFR Supervisors and Quanta Operating Base Managers for impacted regions
- Additional System Operations staff and supervisor(s), if required
- 911 Call-takers: 2 minimum, if required.
- Director of Electric Operations
- Operations Managers – Electric
- Emergency Planning Manager
- Load Office
- Media Relations

Guidelines and Expectations for Consistent Emergency Response

When the on-duty System Operations Supervisor and/or Quanta EOC Manager notifies the regional duty supervisor to open the operating base, these guidelines will be followed to ensure efficient and effective emergency response:

Duty supervisors notify all required area support on Emergency Response Plan. Initial focus during the early hours of the storm will be to assess damage, collect information, analyze and formulate a restoration plan.

Damage assessment teams will be quickly assembled and dispatched. Teams will be made up of qualified electrically trained and experienced personnel from both Quanta and PSE. Damage assessment teams will report back to the operating base Damage Assessment Coordinator.

Damage assessed by first responders (PSE servicemen) will be reported back to system operations and/or electric dispatch, who will then relay the information to Quanta for crew response.

Damage assessment priorities will generally mirror restoration priorities:

- Transmission lines and switching stations
- Distribution substations and distribution feeders
- Distribution laterals
- Individual service lines

The first priority for PSE servicemen will be to:

- Respond to emergency calls from fire, police and other 911 sources.
- Make hazardous areas safe for the public and PSE employees
- Secure unsafe sites before moving to service restoration

Within 24 hours of the event, the operating base and the EOC will provide a high level characterization of the impact and estimated hours/days to restore service; e.g. 3 – 5 days. Within 48-72 hours (depending on the severity of the emergency event), the EOC, working with the operating bases and corporate communications will message estimated restoration times for geographic areas. Specific customer restoration times will be communicated as soon as the operating base personnel has the necessary damage assessment and crew repair work duration times available.

Mobilization

The first phase of emergency response is initial mobilization. The on-duty System Operations Supervisor in System Control contacts Quanta's local regional duty supervisor(s) if the event affects only one to three regions; and/or in a widespread event, the Quanta EOC Duty Manager.

Quanta management starts the process by opening the local operating base(s) and contacting the principal emergency response personnel, as follows:

- Operating Base Manager
- PSE First Response Supervisor
- PSE Electric Dispatcher
- CLX Information Specialist

Mobilizing Staff

Each Operating Base Manager and PSE First Response Supervisor is responsible to mobilize staff for their assignments based on callout lists and specific skills.

These lists include:

- First Response Servicemen
- Storm Board Coordinator / Assistant
- Storm Board Analyst (EMS, DDD) / CLX Specialist
- Damage Assessment Coordinator
- Damage Assessors
- Drivers
- Make Safe teams
- Crew Coordinator (General Foreman)
- Line Personnel
- Communications Coordinator
- Contract Crew Coordinators
- Other emergency response personnel identified on the local area's Electric Emergency Response organizational chart

Mobilization Activities

Who	Does what
Quanta Operating Base Manager / EFR Supervisor	Opens operating base on request, calling in required personnel to perform emergency functions e.g., Damage Assessment Coordinator, Damage Assessors, Crew Coordinator, Storm Board Coordinator/Assistant, Communications Coordinator, CLX Information Specialists, etc. Reviews list of personnel currently working in emergency area and restoration priorities provided by on-duty System Operations Supervisor. Assumes responsibility for all outage restoration and all field crew management in area assigned. Works closely with PSE management on site as well as EOC staff to ensure adequate resources and service is restored in accordance with PSE guidelines. Monitors outages and directs crew personnel to priorities first. Monitors CLX and remains in contact with on-duty System Operations Supervisor for updated restoration priorities. Implement staffing plan ensuring operating base and crew coverage 24/7 (for example, shift changes and rest periods). Communicates regularly with the EOC and/or on-duty System Supervisor estimated restoration times for areas in region, resource requirements, etc.
Electric First Response Supervisors and Engineering	PSE Electric First Response Supervisors and PSE & Quanta engineers will be stationed at operating bases to assist with storm board management, circuit definition, customer outage estimates, etc. Their expertise in DDD, EMS, customer issues for a specific area, etc. will assist Quanta management in service restoration and emergency management. PSE First Response Supervisors will manage all first responder (servicemen) activities in the area assigned and in collaboration with Quanta management, allocate servicemen to patrol duties and/or service restoration as required.
First Response Servicemen	PSE's first responders (servicemen) quickly respond to 911 and other emergency calls. They ensure damaged areas are made safe for the public and employees. Servicemen patrol and assess transmission lines, cut, clear and switch to ensure that critical transmission lines are picked up in priority order followed by distribution substations and circuits.

Who	Does what
	Servicemen provide regular status updates to the Dispatcher at the Operating Bases and to System Operations. Lastly, servicemen repair individual service lines.
System Operations	Monitor weather and zone forecasts *at least every 6 hours*. During critical weather periods, monitor and proactively seek weather condition updates from the National Weather Service (NWS). Distribute weather data to PSE First Response, EOC duty teams and Quanta operations management by telephone, e-mail and/or fax. Implement staffing plan for System Operators to ensure adequate coverage 24/7. Alert Director of Electric Operations, Emergency Planning Manager, and EOC Duty Manager of pending event. As needed, call in personnel to assist with Dispatch, CLX, 911 calls, System Operations, etc. Direct operating bases to open as needed – open as early as possible to avoid response delays. Provide detailed information to regional operations duty supervisors regarding personnel already dispatched and in field working, status of area damage, EOC opening, etc. Coordinate resource deployment with regional duty supervisors and EOC.

Damage Assessment

Many sources of information can be used to assess the status of the electrical system during an emergency. The Storm Board Coordinator and Damage Assessment Coordinator review the information and use it to allocate resources for restoration and estimate restoration time for customers.

Frequently used information sources are as follows:

Information Source	How Source is Used
CLX Outage Management	Logs outage calls received by the Customer Access Center. Provides reports on location, circuit, number of customers affected, estimated time of restoration, etc.
Customers	Provides information to the Customer Access Center, Major Accounts via dedicated phone line to System Operations Supervisors' office, or through city/county 911 centers.
Distribution Data Display (DDD)	Displays geographical data about PSE's electrical system, including the location of customers who have called to report outages.
Energy Management System (EMS)	When available, indicates circuit breaker status (open or closed) and power flow in transmission and distribution stations.
Outage Dashboard	An outage summary page on PSE's intranet, PSEWEB. Information from the Meter Data Warehouse and CLX are merged to graphically depict outages and their current status. Allows quick assessment of current response efforts and overall scope of an outage event, including customer counts by city name.
AMR Outage Map	Another page on PSEWEB, the AMR Outage Map is a graphical representation of PSE's service territory, displaying AMR poletop units that have lost power. This view provides a quick visual image of outages across PSE's distribution system.
Field Personnel and Damage Assessment teams	Provides damage assessment directly to the Damage Assessment Coordinator.
Fire and Police Departments and other City/County Emergency Services personnel	Provides information about damage, location, and priority to System Control.
PSE Servicemen	Provides damage assessment directly from the site to System Operations/Trouble Dispatch/Operating Base.

Using Information Systems to Assess Damage

The Energy Management System (EMS) and CLX systems are generally the first sources of information used by the Damage Assessment Coordinator to determine which transmission lines and substations are out. The Distribution Data Display (DDD) system is used throughout the event to help determine exactly where the system is damaged. The DDD system can provide more localized information on where outages have occurred than the CLX system. 911 calls also help determine exact locations of system damage.

The information from the EMS, CLX, and DDD systems is supplemented by field reports from servicemen. The Crew Coordinator and Quanta Storm Managers use this information to dispatch crews to facilities that have the highest priority for repair. In some cases, Quanta Storm Managers may initially break four-person crews into two-person crews to assess and restore high-priority, easy-to-repair damage.

As each component of the electrical system is repaired, the Damage Assessment Coordinator and Storm Board Coordinator are informed and the DDD or CLX system is updated accordingly.

The AMR outage map provides a quick, visual image of AMR poletop outages across PSE’s service territory.

Role of Damage Assessors

Damage Assessors may be mobilized at the request of storm management. The Damage Assessors and assigned drivers report to the Damage Assessment Coordinator who provides instructions on which circuits to assess.

The Damage Assessment Coordinator may send the Damage Assessors to the field to meet at a predetermined location with a Local Area Coordination Site Manager. In some storms, the Damage Assessors and drivers may be sent out with tree crews, flaggers, and/or wiremen, and work as a team, reporting to a Local Area Coordination Site Manager.

Damage Assessors, who also qualify as Contract Crew Coordinators, may assess damage first and then serve as Contract Crew Coordinators when foreign crews arrive.

Updating ConsumerLinX Outage

ConsumerLinX (CLX) communicates outage and restoration estimates online to the Customer Access Center, Corporate Communications, and other users. CLX immediately updates the IVRU, which provides updates to customers.

Information is needed about outage locations, outage materials, and approximate restoration time. This information is relayed from Damage Assessors, Local Area Coordination Site Managers and Servicemen in the field to the Storm Board Coordinator or Damage Assessment Coordinator who estimate how long it will take for the crew(s) to restore power.

The CLX Information Specialist uses this information to update CLX. The estimated restoration time for each outage area is input to the CLX system. Best-case to worst-case estimates for restoring a particular customer's service in an area can range from several hours to several days.

Repairing Facilities

To reduce outage duration, PSE will restore first and then repair.

During restoration efforts, all crews will restore power by the priority of *what makes sense electrically* rather than by area boundaries.

Repairs delayed to a more appropriate time will be tracked locally to ensure later scheduling and completion. In a major event, an assessment of repairs, resources, and schedule will be determined before releasing outside resources.

Restoration Priority #1: Transmission System

The transmission lines and transmission substations are the highest priority for restoration. Power Dispatchers in the Load Office, or their designees, will request crews and other assistance to restore the transmission system as soon as possible. As the emergency progresses, the Power Dispatchers provide restoration priorities for transmission lines and stations to the appropriate operations regions, Substation Department and Emergency Operations Center.

All regional operations personnel and related departments work with the Power Dispatchers and their designees to *identify outages, stabilize, and repair* the transmission system as their number one priority.

Regional Transmission

Each region has identified its transmission restoration priorities. These restoration priorities follow the general corporate restoration guidelines of restoring the maximum number of customers in the least amount of time, but are more specific, listing circuits and substations by name. They are reviewed annually and updated in each region.

The following table offers high, medium, and low restoration priority guidelines for the transmission system:

Priority	Transmission Lines That Are . . .
High	Connected to critical generation Critical inter-utility connections Greater than 100 MVA of load affected by outage Serving more than 25,000 customers Radial feeds T-lines that are needed to avoid overloads in the remaining transmission system
Medium	Segments that are part of a loop, but where substation(s) are affected Greater than 50-100 MVA of load affected by outage Serving 10,000 to 25,000 customers T-lines that are needed to avoid under-voltages in the remaining transmission systems
Low	Segments that are part of a loop where no substations are affected Less than 50 MVA or less of load affected by outage Serving less than 10,000 customers Outages do not cause service interruptions

Restoration Priority #2: Distribution Substations

As many substations as possible are restored by partitioning and isolating damaged portions of the high voltage system. Restoration of loops is secondary in the initial phase of restoration.

Substations

High	Medium	Low
>6,000 customers affected by outage. Distribution substations serving critical loads: • Hospitals, airports, public transportation, police, fire • High density urban/residential areas • Key accounts, Schedule 48, and other "at risk" customers • Other industrial and commercial load with large loss due to process disruption • Substations that can be returned to service quickly	4,500-6,000 customers affected by outage Distribution substations serving: • Emergency shelters, blood banks, nursing homes, schools • Medium density residential areas • Community wells, sewer lift pumping stations	< 4,500 customers affected by outage Distribution substations serving: • Low density rural areas • Accounts with adequate back-up generation • Substations that take a significant amount of time to repair

Restoration Priority #3: Distribution Feeders

System Operations, First Response Management and Quanta directs servicemen and crews, working with all operations regions, to restore and energize the feeder system. This work takes priority over restoring primary laterals. As damage assessment teams report back to their respective service center, all feeders, or portions of feeders found to be in the clear will be re-energized as ordered by System Operations.

Each operating base has a regional list of critical facilities for restoration priority when feasible. These lists are updated annually in conjunction with regional government emergency management staff, PSE's major and business account services and information provided by the jurisdictions.

Transmission Effect on Distribution Feeders

Energizing distribution feeders may be delayed in some cases until transmission lines are back in service and capable of withstanding the additional feeder load.

Distribution Feeders

High	Medium	Low
>2,500 customers affected by outage. Distribution feeders serving: • Hospitals, airports/ public transportation, police & fire • High density urban/ residential areas • Key accounts, Schedule 48, and other "at risk" customers • Other industrial/ commercial load with large loss due to process disruption • Feeders that can be repaired quickly	1,500-2,500 customers affected by outage. Distribution feeders serving: • Medium density residential areas • Emergency shelters, blood banks, nursing homes, schools • Community wells, sewer lift pumping stations	<1,500 customers affected by outage. Distribution feeders serving: • Low density rural areas • Accounts with adequate back-up generation • Feeders that take a significant amount of time to repair

Restoration Priority #4: Distribution Laterals

When the feeder system is restored, the fourth priority is restoration of distribution laterals. Laterals usually are prioritized on a case by case basis. The emphasis is to restore the largest number of customers in the shortest possible time. As soon as practicable, crews will transfer de-energized circuits to live circuits or substation.

Restoration Priority #5: Individual Service Lines

Service lines, particularly those in remote areas, will most often be last in priority order for restoration. This will depend on crew or servicemen availability, location, and other ongoing restoration efforts.

Repair Planning

As soon as possible after system restoration, the following personnel will document abnormal conditions existing after the storm:

- Regional Operating Base Management
- System Operations
- Power Dispatchers
- Servicemen
- Electric First Response Management
- Dispatchers
- Meter Department and Substation personnel (include, if available)

Listed below are some standard post-emergency activities:

- Check temporary circuits, alternate feeds, and emergency repairs for capability of carrying peak loads until permanent repairs are made.
- Note abnormal feeds and return to normal.
- Patrol all sections of the distribution system where tree wire is installed, ensuring it is free of any limbs or in contact with leaning trees.
- Report temporary repairs and make permanent repairs.
- Prepare outage reports, note system weaknesses for correction, and critique restoration procedures.

Closing Operating Bases

The decision to close an operating base will be made by the Quanta Operating Base Manager ***in collaboration with*** the on-duty System Operations Supervisor, on-duty Quanta EOC Manager, and the EOC (if open).

To ensure continued availability of resources, the following considerations will be made:

- Continue base operation with minimal staff – one supervisor, one crew and CLX support.
- Plan for reopening operating base the next morning, and/or have plan in place if base should need to reopen later at night or early morning hours.

SECTION 5 - CONCEPT OF OPERATIONS – GAS

Gas Facility Failures

Emergency Information Sources

How PSE is Notified

The Customer Access Center receives trouble calls from customers of all types. Gas Dispatch and Gas Control receive trouble calls directly from area 911 centers. Information is most commonly received via normal phone line.

Information may also come directly to individual employees as part of their normal work, through their interactions with work contacts, or through relationships in the community. Employees of PSE and/or its' service providers who are likely to receive word of service problems include the following:

- Gas/Electric personnel
- Major Account Executives
- Government and Community Relations Managers

Media reports and reporters' inquiries may also call PSE's attention to major service disruption problems. In addition, System Control personnel detect problems in the course of monitoring automated gas transmission /distribution information systems

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Service Orders

Trouble calls received via the Customer Access Center are entered into ConsumerLinX (CLX) and result in service orders being queued and immediately printed to gas dispatch.

Orders are systematically routed to a specific dispatcher based upon the geographic region the address is located within. To ensure immediate response, emergencies such as gas odors or reports of broken gas pipe are expedited through priority handling by gas dispatch.

These emergency service orders are transmitted to field personnel through the Mobile Workforce Management system with confirmation by radio or telephone.

Incidents Requiring Immediate Action

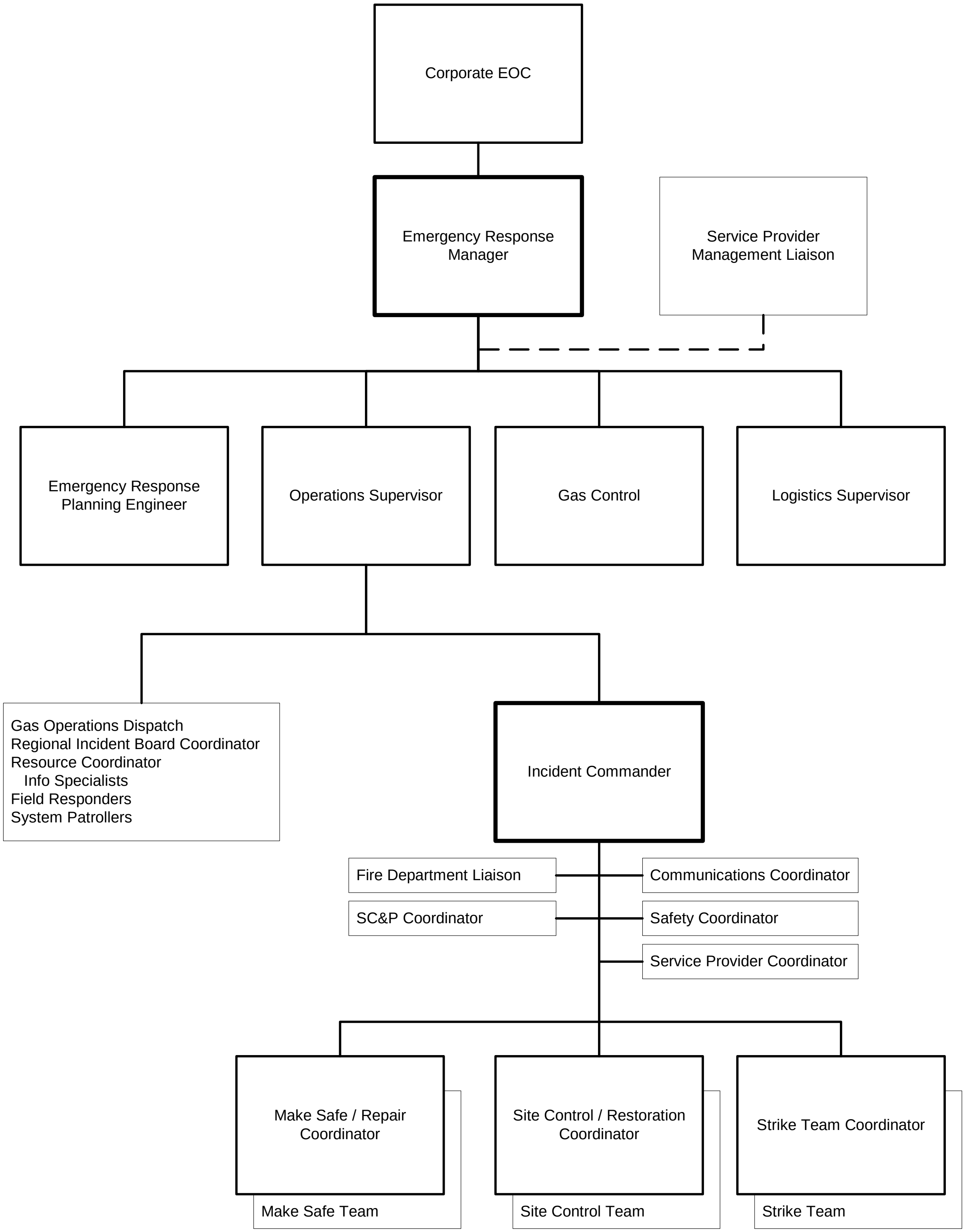
Incidents that require immediate action are those that:

- Involves the uncontrolled escape of gas into the atmosphere or into the ground, that presents a risk to persons or property.
- Generate a request for assistance from a local emergency response agency.
- Generate a customer call that indicates a gas odor or a dangerous malfunction of an appliance, regardless of the cause.

Gas Emergency Organization Structure

Puget Sound Energy's gas emergency response plan utilizes principles of the Incident Command System (ICS). ICS is modular (Command, Operations, Planning and Logistics), allowing event response to be scaled, depending on the number of field incidents being responded to at any point in time. The response to major gas emergencies will be coordinated through the Gas Planning and Strategic Center (GPSC).

Gas Emergency Organization Chart



Gas Emergency Response Roles

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Corporate EOC	Community & External Relations Manager	Works with Customer Access Center Supervisor and EOC communications coordinator to ensure that updated assessment and restoration information corresponds with that given to Customer Access Center point desk for IVRU and media updates. Provides information to local media, municipalities, and county emergency response departments (if there is no EOC liaison) on outage assessment and restoration efforts. Works closely with the emergency response managers' corporate incident status board to stay current with the progress of the various events.	Emergency Response Overview
Gas Planning and Strategy Center (GPSC)	Emergency Operations Supervisor	This role is located at the GPSC during major events. Using the incident status boards as a tool to view what is going on in a given area: • Works with the GPSC team to help set response and repair priorities and ensure that the appropriate resources are dispatched to the sites. • Depending on the size of an incident and the involvement on our system, there may be multiple Emergency Operation Supervisors responsible for distinctly separate geographic regions of the gas system. • Oversees meter shutoff, system isolation, repair and restoration of customer service efforts. • Oversees the use of the emergency truck and the incident command vehicle (mobile command center).	Incident Command; Emergency Response Overview

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
		• Cooperatively works with the Emergency Response Planning Engineer and the on-site Incident Commander to determine system operating characteristics and appropriate shutdown or diversion processes. • Works with Gas Operations Dispatch to determine appropriate method of generating service tickets (whether by the manual emergency meter shut-off process or system modeling).	
Gas Operations Dispatch	Dispatch Supervisor	May be called on to fill multiple roles including that of Emergency Response Supervisor. Responsible for dispatch operations ensuring adequate staffing and smooth operations.	Emergency Response Overview
Gas Planning and Strategy Center (GPSC)	Emergency Response Manager	Oversees company-wide operations, emergency response assessment, and restoration. Primary contact person with EOC, System Control, and Customer Access Center. Assesses needs for additional resources, coordinating with EOC for external assistance as require including personnel from other districts or departments. Reports to Director-Gas Operations. Maintains a system-wide view of the ongoing status of all identified incidents through a corporate incident status board maintained by the administrative support and board coordinator. Reporting to the Emergency Response Manager: ▪ Emergency Operations Supervisor(s) ▪ Logistics Supervisor ▪ Response Planning Engineer	Emergency Response Overview

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Gas Planning and Strategy Center (GPSC)	Information Specialist or Data Coordinator	Interacts closely with the Emergency Operations Supervisor, Dispatch and the Incident Board Coordinators Updates outage information online, captures data from system patrollers and posts it online for general viewing. Interacts with the Customer Access Center to provide status updates.	Emergency Response Overview
EOC or GPSC (depending upon the event)	Major Account Rep	Communicates with assigned major or other key accounts (industrial customers, school districts, etc.) throughout emergency. Provides estimated restoration information. Assists with customer needs. Reports to Community and Government Relations Manager.	Emergency Response Overview
Gas Planning and Strategy Center (GPSC)	Regional Incident Board Coordinator	Manages and updates a gas "storm board" to ensure tracking of gas system damage, crew jobs as well as location of resources and customers needing emergency care. Additionally, the map boards track logistical problems (impassable roads, etc.) Works closely with dispatchers and the information specialist/data collector to keep the regional incident boards updated.	Emergency Response Overview
Gas Planning and Strategy Center (GPSC)	Resource Coordinator	Coordinates staffing for company field personnel, service providers and special equipment, including emergency truck, Plidco, large steel squeezers, etc., as required by each area. Tracks extended duration shifts and provides input on rotations. Works closely with the Emergency Operations Supervisor and Gas Operations Dispatch.	Emergency Response Overview

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Gas Planning and Strategy Center (GPSC)	Service Provider Management Liaison	Provides the service provider with updated even information, allowing the service provider to route qualified resources to the areas requiring attention.	Emergency Response Overview
	Logistics Supervisor	Staffs emergency support service functions, including: • Material acquisition and delivery • Temporary field staging area (tents and/or office space) • Meals and lodging coordination • General office and administrative support Determines appropriate use of personnel to perform the following functions: • Material acquisition & delivery – includes coordinating with service providers to ensure that materials required for permanent repairs are available on-site. • Meal & lodging coordination. • Office support (faxing, word processing, phone assistance, petty cash, etc.)	Emergency Response Overview
Incident Command Post	IC - Communications Coordinator	This role may be the responsibility of the Incident Commander; however as an operation grows to the point that the IC is overburdened, this role will be filled. Communicates with the incident site and Operations Dispatch.	Incident Command; Emergency Response Overview
Incident Command Post	Damage Assessor	Trained fitter and customer service personnel who are commonly dispatched to reports of gas odors or broken and blowing situations. Assess situations and take whatever actions are required to make the situation safe. Upon investigating the reported problems, the Damage Assessor will contact dispatch for the required additional resources.	Emergency Response Overview

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Incident Command Post	Fire Department Liaison	Provides communications link between the Incident Command Post and emergency response organizations (fire/police).	Incident Command; Emergency Response Overview
Incident Command Post	Incident Commander	On-site responsibility for all field operations, including safety. Acts as the main contact for police and fire department personnel. All communications are directed through the on-site Incident Commander. Reports directly to the Emergency Operations Supervisor.	Incident Command and Emergency Response Overview
Incident Command Post	Make Safe/Repair Coordinator	Works with the Incident Commander to develop the Incident Action Plan. Oversees situation control and repair.	Emergency Response Overview
Incident Command Post	Meter Shut-off Personnel	Reads service outage tickets, shuts off and locks gas meters as requested. Performs required record-keeping. May be staffed by meter readers, electric helpers, etc.	General Overview of Single Incident Response Efforts; Reading Service Outage Tickets; Gas Meter Shutoff & Locking Procedures
Incident Command Post	Safety Coordinator	During a large-scale gas emergency, the PSE Incident Commander may request or appoint a qualified person to act as the Site Safety Coordinator. This is required when the size and scope of the operation is so large that effective oversight of employee and public safety requires additional assistance. Assists the Incident Commander to minimize confusion and congestion during an emergency by overseeing safety aspects of the operation.	Emergency Response Overview
Incident Command Post	Service Provider Coordinator	Reports to Incident Command Post. Interacts between service provider crews and Incident Commander.	Emergency Response Overview

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
Incident Command Post	Site Control/ Restoration Coordinator	Manages the work group who monitors the perimeter of an incident, shuts off meters and restores service to customers. May monitor the spread of gas, control access to a safety zone, and light-ups.	Incident Command; Emergency Response Overview
Incident Command Post	Strike Team Coordinator	As warranted by the type/size of an emergency, this position will direct special teams with a single purpose.	Incident Command; Emergency Response Overview
Incident Command Post	System Control & Protection (SC&P) Coordinator	Responsible for all SC&P work at emergency site.	Incident Command; Emergency Response Overview
Incident Command Post	System Patroller	At the direction of the Emergency Operations Supervisor, patrol predetermined areas of the system for damage – potential and actual. Position is usually staffed by Public Improvement Inspectors.	Emergency Response Overview

Gas Facility Failure Staffing

The following table lists the temporary job and reporting structures that are commonly used for specific events:

Temporary Job Title	Reports To
Emergency Response Manager	Director of Gas Operations
Response Planning Engineer	EOC and/or Emergency Response Manager
System Modeler	Response Planning Engineer
System Analyst	Response Planning Engineer
Field Liaison	Emergency Operations Supervisor
Emergency Operations Supervisor	Emergency Response Manager
Meter Shut-off Personnel	Incident Commander
Service Relight Personnel	Incident Commander
Logistics Supervisor	Emergency Response Manager
Community/External Relations Manager	EOC
Major Accounts Representative	Emergency Response Manager

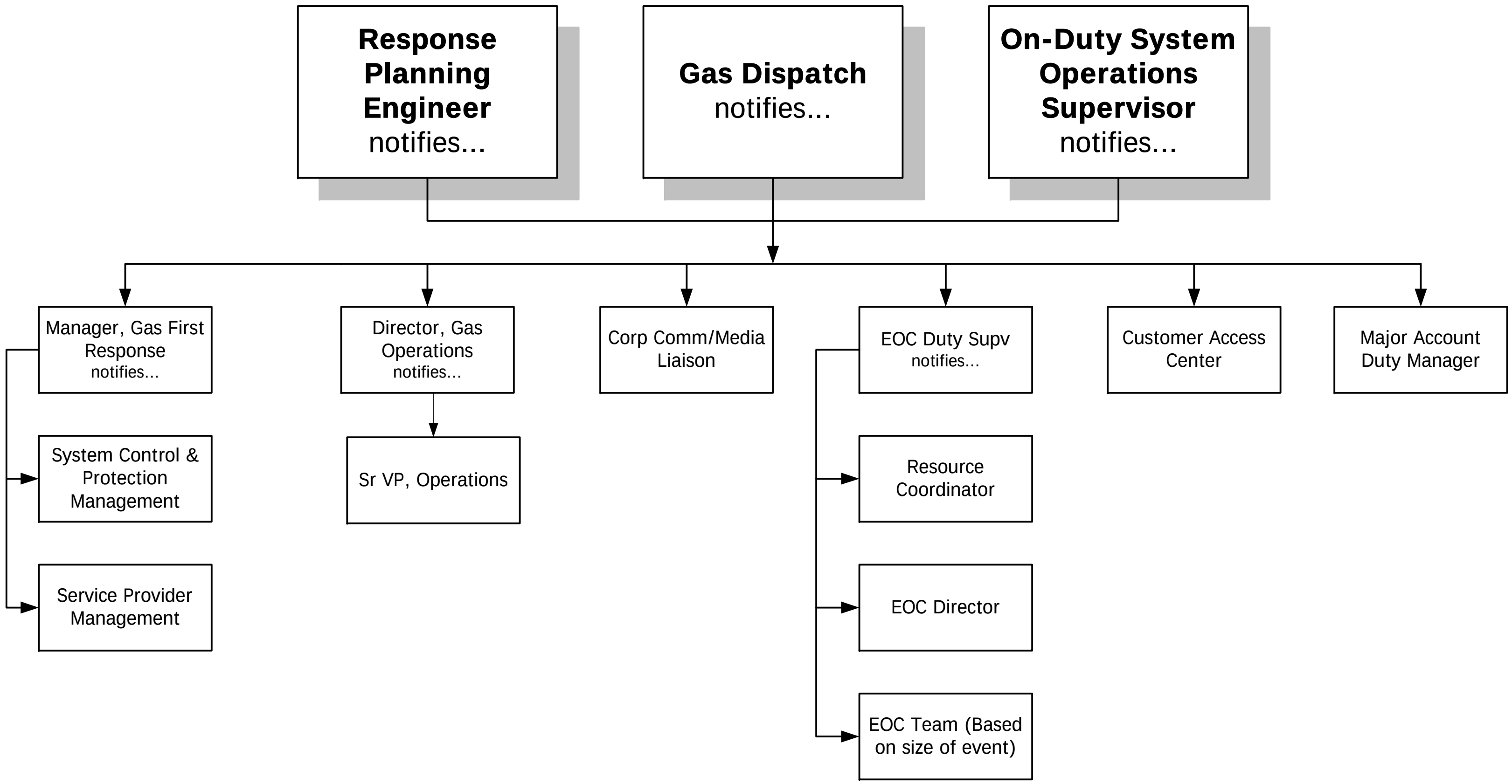
Plan Activation

As cold weather conditions arise and/or other gas emergencies occur, the Gas Duty Manager and the Response Planning Engineer monitor the company's readiness to respond. Either one of those positions will decide when to take emergency action and/or open the Gas Planning and Strategy Center (GPSC).

Once the GPSC is open, the Emergency Response Manager is responsible to request the opening of the EOC.

In preparation for emergency response, the following notification process is implemented:

PLAN ACTIVATION and NOTIFICATION PROCESS
MAJOR GAS EVENT
Revised 10/2005



NOTE: The ERPS, Gas Dispatch, and/or Gas First Response may activate an EOC response. During Cold Weather events, it is typically a joint decision initiated by the ERPS, Total Energy System Planning, System Control & Protection, Gas Control, Gas Measurement, Manager Gas First Response and selected officers.

Assessment – Types of Incidents

The following table lists types of incidents covered in this section and their characteristics:

Incident Type	Characteristics
Direct gas involvement	Call may be received from the general public, building occupants, or emergency agencies. Competent emergency response persons may or may not be at the site upon arrival of first responder. • Broken and blowing gas service or main. • Main or service obviously stressed due to ground movement and in danger of imminent failure. • Building explosion with gas as primary cause. • Structure fire with gas as primary cause. • Any report of burning gas. • Early indications of area gas outage – unknown cause. • Blowing relief valve. • Vehicular contact and damage to above-ground gas facility. • System over-pressure or low pressure. • Reports of personal injuries or property damage related to gas.
Indirect gas involvement	Call usually originated by emergency response agency that is already at the site and in control. • Fire in structure with gas service but there is no gas burning nor in area of fire. • Utility calling to report odor in vault or chamber. • Explosion or hazardous malfunction in building using gas for industrial process. • Hazardous gas levels in areas such that persons or structures are placed at risk, when source of gas is not identified. • Explosion or fire in structure where gas is not directly involved.
Unknown gas involvement	Unidentified odors. Reports of unexplained illness. Building explosion or fire in building not served with gas. Any request for support from a local emergency agency.

First Responder's Initial Assessment
The initial element to be assessed by the first responder in any emergency situation is the imminent or potential threat to human life, followed by threat to property. Initial assessment and communication is made *within five minutes*. See Initial Assessment Checklist for more information.

First responders follow these steps when on site at a gas facility failure:

Step	Action
1	Notify Dispatch upon arrival.
2	Conduct a "windshield" assessment.
3	Proper personal protective equipment.
4	Evaluate immediate threat: Life, injury, fire property Secure perimeter Eliminate sources of ignition
5	Determine scale of emergency: Volume/blowing gas Severity of damage Need for immediate backup
6	Verify location in relationship to: Building address Street location
7	Communication with agencies on-site: Fire (check-in with Incident Command) Police (traffic control, if necessary) Media (defer until appropriate personnel is on-site)
8	Notify Dispatch: Observations Location of Incident Command Assignment of incoming personnel

Step	Action
9	Other considerations: Possibility of multiple leaks Underground migration of gas Access to site Staging area for incoming personnel and equipment Bystanders Minimize number of personnel exposed to danger
10	Prepare for second assessment Assemble equipment

Initial Assessment Checklist

The first responder will determine within the first few minutes after arrival what actions are needed to protect people and property. ***Heroic actions that may place a first responder at risk will not be taken.*** Only the most severe circumstances warrant acting independently without back-up support.

Consider the following points when making the initial assessment:

- Focus on the big picture.
- Evaluate life safety issues first, the protection of property second.
- What does the site look like at first observation?
- What other emergency response agencies are on site?
- Has site access been limited?
- Are bystanders a problem?
- Are there obvious injuries?
- Is gas actively blowing?
- Is there a strong odor but no sign of blowing gas?
- Is there a fire? Is it gas-fed?
- Are flammable chemicals at risk?
- Are things occurring at multiple locations or is the action centralized?
- Do the structures have obvious damage? Is collapse possible?

First Responder's Second Assessment

As soon as immediate actions to protect life and property are completed, a more thorough assessment of the situation will be taken, focused on the following steps:

Step	Action

1	Inside Buildings:
	    Evacuation procedures
	        Notify Dispatch
	        911 Call required
	Outside Buildings:
	    Bar test perimeter – initial
	Other Structures:
	    Bar test perimeter – expanded
	        Manholes
	        Catch basins
	        Vaults
	        Other areas where probe can be inserted
	    Possibility of other leaks

2	Inform Dispatch Situation and progress report

3	Continue expanded area check:
	    Expanded evacuation
	    Bar test (expanded)
	    Perimeter security / safety
	        Expanded perimeter / evacuations

4	Remain on-site
	    Until property relieved
	    Situation completed

5	Establish incident command (see GCIS)

Response Process

During a gas facility failure, areas may ask for additional damage assessment assistance. Use the following process to request additional emergency personnel:

Who	Does What
Area Affected	Notifies Gas Operations Dispatch.
System Control and/or Gas Operations Dispatch	Calls Emergency Response Planning Engineer and Gas Duty Manager if callout assistance is requested.
Response Planning Engineer and/or Gas Duty Manager	Uses the Emergency Response Callout List to assemble response planning teams.
Emergency Response Manager	Oversees company-wide operations, emergency response assessment and restoration. Primary contact person with EOC, System Control and Protection, and Customer Access Center (CAC). Assess needs for additional resources, coordinating with EOC for external assistance as required. This may include personnel from other districts or departments. Reports to Director, Gas Operations Maintains a system-wide view of the ongoing status of all identified incidents through a corporate incident status board.
Response Planning Engineer	Provides initial, single point of contact for necessary engineering resources. Responsible for insuring that the GPSC is staffed with adequate engineering resources to provide appropriate engineering support to the field Incident Commander, Emergency Operations Supervisor, and Emergency Response Manager. On significant or non-routine events, responsible for assisting with the development of the incident action plan (IAP), including pipeline shut-down, repair and restoration procedures. Notifies state and federal authorities, as required. Determines the need for further failure analysis on reportable incidents.

Who	Does What
Emergency Operations Supervisor	This role is located at the GPSC. Using the incident status boards as a tool to view what is going on in a given area, works with the dispatchers to help set response and repair priorities, and ensure that the appropriate resources are dispatched to the site. Depending upon the size of an incident and the involvement of gas system, there may be multiple Emergency Operations Supervisors responsible for distinctly separate geographic regions of the gas system. Oversees meter shut-off, system isolation, repair and restoration of customer service efforts. Oversees the use of the emergency truck (contains emergency response equipment) and the incident command vehicle (mobile command center). Cooperatively works with the Response Planning Engineer and the on-site Incident Commander to determine system operating characteristics and appropriate shut-down or diversion processes. Works with Gas Operations Dispatch to determine appropriate method of generating service tickets (whether by the manual emergency shut-off process or system modeling).

Functions by Department

The following table details the duties and responsibilities of various departments:

Who	Does what
Total Energy System Planning – Emergency Response Planning Function	Notifies State and Federal authorities, as required. When service has been restored, Standards and Work Practices promptly submits written reports, as required.
Gas System Operations	Initial curtailment. Identifies large-volume interruptible or transportation customers deemed necessary that will be greatly affected by facility failure. This includes curtailing gas service. Performed in conjunction with Energy Measurement. (Gas Control has access to customers with RTUs; all others are tracked by Energy Measurement). Advises Major Accounts and Key Customer Services which customers are affected/curtailed.
First Response and Service Providers	Patrol key system components to identify problems. Assess reported system failures. Control natural gas emergency situations. Make repairs and restore service.
System Control and Protection	Operates and/or maintains district regulation and high pressure valves. Restores service to commercial and industrial equipment with intermediate pressure (pounds) delivery out of the meter set.

Mobilization

The first phase of emergency response for a gas emergency event is the mobilization of first responders. Gas Dispatch contacts the on-duty Emergency Response Planning Engineer and the Gas Operations Duty Supervisor, and the Gas Duty Manager.

Gas Dispatch will immediately send first responders to the area to ensure the safety of the public. Local area operations, in conjunction with the Gas Duty Supervisor and on-duty Emergency Response Planning Engineer determine requirements for field personnel response, system control, and service restoration.

Gas emergency control efforts will include the following:

- Emergency Response Manager
- Emergency Response Planning Engineer
- System Modeler
- Field Liaison
- Emergency Operations Supervisor
- Logistics Supervisor
- Community and Government Relations Manager

Mobilizing Staff

PSE and Service Provider supervisors are responsible for mobilizing staff assignments based on callout lists and specific skills.

These lists include:

- Customer Field Service Technicians from other areas
- Field crews
- Other emergency response personnel identified on the local area's Gas Emergency Response Organizational Chart

The GPSC's initial focus is to obtain damage assessment information and restoration estimates. GPSC will coordinate the overall emergency response effort, moving resources between affected areas. The GPSC will act as a central clearinghouse of information for media and customer purposes.
When requested by the GPSC, EOC personnel work with local area personnel or outside sources to obtain additional workers and materials to restore the system. These resources (crews, engineers, telephone answering personnel, or equipment) should be delegated to the areas designated by the GPSC.

Acquiring Resources (Material / Equipment)

Acquiring resources is the process of procuring and dispensing material and equipment. Normal operations are maintained, with extended services during emergencies. (See Resource Acquisition in the *Appendix* for more information.)

Support Services provides assistance through the following departments:

- Materials Distribution
- Purchasing
- Fleet

In cold weather, materials are supplied from the local warehouse and supplemented by the central warehouse, or procured through purchasing. The materials duty supervisor will contact purchasing for materials not carried in stores.

Fleet services are provided through the local garage or from the central garage. Callouts are made through Gas Operations Dispatch from the seniority list. If contact cannot be made, or activity is too great, Duty Supervisor Fleet is called to assist.

During cold weather, areas may ask for assistance through Gas Operations Dispatch, or by contacting warehousers or fleet staff assigned to the local facility.

Use the following process:

Who	Does What
Gas Field Operations	Notifies Gas Operations Dispatch for materials or fleet
Gas Operations Dispatch	Calls out local staff or other necessary staff by seniority. If necessary, calls the material or fleet duty supervisor for material or fleet assistance.

If the GPSC is Open…

This group…	Is responsible to…
Field Operations	Make a request to GPSC for personnel and equipment. Advise GPSC of crew's availability and reassigns or releases crew as appropriate. Prepare work assignment and required support prior to crew's arrival. Record time of arrival and crew composition. Notify GPSC when crew is ready to be released.
EOC	Assemble specifically requested labor pool and equipment and dispatch to operating area. Notify local area operations when the crew was dispatched, what equipment and personnel were included, and the estimated time of arrival. If restoration estimates are very different between areas, work to move resources between areas to balance restoration time frames. Makes requests for outside assistance through the EOC.

System Restoration

The following table defines criteria for prioritizing gas service restoration:

High	Medium	Low
Public hazard: Broken and blowing Gas odor or flame Pipe/infrastructure exposed or at risk High pressure supply (steel pipe 2-20 in.) Facilities serving hospitals, airports, public transportation, police, and fire High density urban/ residential areas Other industrial/ commercial load with large loss due to process disruption Firm or "at risk" customers	Intermediate pressure (IP) distribution feeders (plastic or steel 4-8 in.) Local IP distribution lines (1¼-2 in.) Facilities serving: ▪ Medium density residential areas ▪ Emergency shelters, blood banks, nursing homes, schools	Low pressure (LP) distribution Individual (isolated) services Low density rural areas Interruptible customers

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SECTION 6 - COLD WEATHER ACTION PLAN

How PSE is Notified

Problems due to cold weather are often identified and reported by customers to the PSE Customer Access Center, and then routed to System Control or Gas First Response through Gas Operations Dispatch.

Because cold weather is expected, there may be times when gas consumption exceeds system capabilities. In anticipation of this event, PSE takes actions to minimize or prevent problems.

Who PSE Must Notify

If a system failure occurs, System Control notifies all appropriate local emergency agencies as well as:

- Gas Operations Duty Personnel (including Emergency Response Planning Engineer)
- Manager Gas First Response
- Major Accounts
- Corporate Communications
- Manager System Control and Protection
- Manager Gas System Operations

Communications

Internal Communication
PSE and Service Provider field crews shall communicate using company radios or cell phones. System Control Gas Operations Dispatch may set up an emergency channel on the radio system when deemed necessary. The PSE radio system is the <u>preferred</u> method for group actions.

External Communication
External communication will be done through Corporate Communications. System Control, with support from Total Energy System Planning, will advise Corporate Communications, Major Accounts, and the Customer Access Center *within 30 minutes* of becoming aware of a cold weather situation requiring action outside of the normal "Cold Weather Action Plan".

Assessing the Situation

The teams assessing problems associated with cold weather are:

- Total Energy System Planning
- First Response Operations
- System Control and Protection
- Gas System Operations

Scheduling and Prioritizing Work

Work is scheduled and prioritized by System Control and Protection, GPSC, with the assistance of Total Energy System Planning and Gas Control, working with contracted service providers.

Mobilizing Personnel

GPSC, Gas Operations Dispatch and/or Gas Control will mobilize any personnel deemed necessary for facility failures.

Gas Operations will use the Cold Weather Action Plan as developed by Total Energy System Planning to support:

- Cold weather bypassing
- Liquefied Natural Gas (LNG) usage
- Compressed Natural Gas (CNG) usage
- The Cold Weather Action Plan includes field assignments, phone numbers, and detailed system information.

Installing Facilities

New gas facilities may have to be installed on an emergency basis during cold weather.

Total Energy System Planning is responsible to determine the facility type and the timing of such installations.

Total Energy System Planning
Before November of each year, Total Energy System Planning (TESP) is responsible for the following:

Step	Action
1	Determine the impact of pressure loss due to cold weather. Determine a safe method of restoration.
2	Identify actions necessary to maintain customer service before cold weather occurs, such as: • Completion of work requested via SAP • Adjustment list for LP regulator stations

<table>
<tr><th>Step</th><th>Action</th></tr>
<tr><td>3</td><td>Prepare a Cold Weather Action List for System Control and Protection on specific cold weather actions to be followed during peak hours and high loads.
Base list on predicted and actual system send-out.
System pressures as reported by pen gauges, RTU printouts, and bypass reports.
Update information from design and system changes.
Index the list from predicted total system send-out (cumulative from 4:00 AM to 8:00 AM as predicted by Gas Control).
Date and send the list to:
• Director, System Planning & Performance
• Manager, Safety
• Manager, Standards and Work Practices
• Director, Operations
• Director, Gas Operations
• Director, Asset Management
• On-duty System Operations Supervisor
• Manager, Gas System Operations
• Manager, System Control and Protection
• Managers, Gas First Response</td></tr>
<tr><td>4</td><td>Assist Energy Measurement and Gas Supply in determining the most effective method of customer curtailment in problem pressure areas.</td></tr>
<tr><td>5</td><td>Provide information on potential outages on maps to
• Major Accounts
• System Control and Protection
• Gas First Response
• Maps and Records Technology to develop isolation area plans</td></tr>
<tr><td>6</td><td>Maintain a book of information on
• Weather forecasts
• Sea-Tac temperatures
• Predicted and actual system flows
• System pressures
• Customer curtailments and outages
• Cold weather actions (bypassing, IP valve opening, CNG injections) for times of peak flows</td></tr>
</table>

Gas Control

On a daily basis, Gas Control is responsible for the following:

Step	Action
1	Work with Energy Measurement as required, to notify any customers deemed necessary that would be greatly affected by cold weather, including curtailment of gas service. If large numbers of interruptible customers are affected, enlist help from other departments with curtailment calls.
2	Work with Energy Measurement as required, to advise Major Accounts which customers are affected/curtailed.
3	Send a copy of forecast to: • Senior Engineer, Total Energy System Planning • Managers, First Response • Manager, System Control and Protection
4	Send to Senior Engineer, Total Energy System Planning: • Daily Gas Send-out Summary Report • Daily Gas Statistics Report • Min/Max Report (for time between 10:00 PM of previous day and 10:00 AM of current day) • Daily Bypass Summary Report containing locations that were bypassed, IP valves opened, and LNG and CNG injection locations. List should contain: • Location name • Time on, time off • Curtailment Report listing all customers (or classes of customers) who were requested to curtail use during peak hours of present day
5	On request, compile and send to the Senior Engineer, Total Energy System Planning, a list of customers that did and did not actually curtail gas usage as requested—including usage flows (scfh) and times (when possible).
6	By 1:00 PM, fax the Gate Take Forecast Report to: • Senior Engineer, Total Energy System Planning • Manager, Gas First Response • Manager, System Control & Protection Include actual vs. predicted system flow rates (totaled for the period between 4:00 AM and 8:00 AM) of the present day, and predicted system flows (totaled for the period between 4:00 AM and 8:00 AM) of the following day. On Friday or any day preceding a holiday, make predictions for each following day up to and including the next working day (example: Saturday, Sunday, and Monday).
7	Leave the predicted *Gate Take Forecast* and other pertinent information as a pre-recorded message on a pre-determined phone number by 1:00 PM.

Step	Action
8	On mornings when "action" is predicted, direct personnel at field sites and monitor system activity. If any relocation of field personnel is necessary during the course of the morning, notify the pressure control supervisor and Total Energy System planning engineer.
9	By 1:00 PM of the same day that outages due to low system pressures occur, fax a copy of a *Thomas Bros. map with all grouped outages* circled, including the total number of outages, to the Senior Engineer, Total Energy System Planning.

System Control and Protection System Control and Protection is responsible for the following:

Step	Action
1	Operate and/or maintain district regulation and high pressure valves.
2	If an outage occurs, restore service to commercial and industrial equipment with intermediate pressure (pounds) metering and/or inches water column (w.c.) delivery customers with meters larger than 1000 CFH.
3	Daily, monitor weather, gas control load predictions, and the cold weather action listing to predict necessary bypassing resources for the next high load period.
4	Based on the listing from Total Energy System Planning and the load forecasts from gas control, make the necessary arrangements for field resources to be on site as specified. If LNG is to be used, arrange for a qualified operator to be on site. If required, contact Manager First Response for additional personnel to carry out the plan.

System control and Protection Field Personnel Once located on site, but before taking any action, field personnel are responsible for the following:

Step	Action
1	Contact Gas Control and provide the following information: • Who are they? • Where they are located? • How Gas Control can contact them (truck number, radio and/or cellular phone number)?
2	Take the necessary action at the appropriate time, as determined by Pressure Control, Total Energy System Planning and Gas Control (bypass regulators, close and/or open valves, monitor pressures, etc).
3	Complete a *Cold Weather Action Report* when any action is taken to maintain system pressures (bypassing or opening valves).

Step	Action
4	Notify Gas Control when field activity is complete and system integrity is restored. **NOTE:** Gas Control shall release field personnel from any location after the necessary action is complete, and shall notify the Pressure Control supervisor when field resources are released.
5	When requested, send a copy of the completed *Cold Weather Action Report* to the Senior Engineer, Total Energy System Planning.
6	Inform Gas Control and Total Energy System Planning of any observations and/or recommendations regarding the cold weather action list and load forecasts that may assist in future predictions of resource requirements.

Gas First Response Operations

First Response personnel responding to Cold Weather Action work under the direction of System Control & Protection. First response personnel may restore service to commercial and residential equipment with low pressure inches water column (w.c.) delivery out of the meter set (1000 CHF and smaller meters).

Gas Operations Field Personnel

Field personnel are responsible for the following:

Step	Action
1	Initiate CNG injection or regulator station bypass if the pressure drops below that specified on the *Cold Weather Action List.* Notify Gas Control when initiating and when complete with these activities.
2	Initiate Liquefied Natural Gas injection if the pressure drops below that specified on the *Cold Weather Action List.* Notify Gas Control when initiating and when complete with LNG injection.
3	Complete a *Cold Weather Action Report* when any action is taken to maintain system pressures (injecting CNG). Notify the Manager System Control and Protection.
4	When requested, send a copy of the completed *Cold Weather Action Report* to the Senior Engineer, Total Energy System Planning including reports on: • Time on, time off • Manifold pressure before and after injection • System IP pressure before initiating injection

SECTION 7 – EXTERNAL RESOURCES

Contractors and Foreign Crews

Working Rules

All Quanta and Pilchuck and non-Quanta and non-Pilchuck crews and contractors, including out-of-area foreign crews will comply with Washington State regulations. They will work under their own work rules and collective bargaining agreements, but will comply with PSE's construction standards and work practices, including switching practices.

Rest Periods

All personnel working on extended restoration efforts will take adequate rest periods. PSE recognizes the need, depending on when outages occur, to work extended initial shifts. Employees should be given adequate time to eat and sleep. This applies to all employees, contractors, and borrowed workers from other utilities.

Use of Personal Vehicles

During emergencies, employees and contractors may be asked to use their personal vehicles and equipment. Employees and contractors who agree to do so will be compensated for all reasonable business expenses.

NOTE: PSE employees should refer to **Corporate Policy Manual CPM-17** for details. Refer to *Volume II* for a copy of this policy.

Mutual Assistance

Overview

Utilities are often willing to assist one another with personnel or equipment to restore service in an emergency. The disruption may be caused by equipment malfunctions, accidents, sabotage, the elements, or other occurrences that prevent existing resources from restoring service in a timely manner. Mutual assistance provides a cooperative mechanism to augment work force and resources to respond to unusual events that adversely affect customer services.

Participation in mutual assistance is voluntary. The ability to provide assistance may be limited by situations such as the other utility's own conditions or prior commitments. Utilities may belong to a number of mutual assistance rosters, and as a result, prioritize the order in which they will respond to multiple requests for assistance.

Mutual assistance involves two distinct procedures: Receiving assistance, and providing assistance.

PSE's Mutual Assistance Agreements

PSE has voluntary mutual assistance agreements with a few neighboring gas, electric, and combination utilities, as well as being a signatory to the following Mutual Assistance Agreements.

- Western Region Mutual Assistance Agreement (WRMAA) – The Western Energy Institute (WEI) is the custodian of this agreement.
- Edison Electric Institute (EEI) – Restore Power
- American Gas Association (AGA) – Natural Gas Operations Assistance Program

Additional information for each agreement may be found in Volume II of the Corporate Emergency Response Plan.

SECTION 8 – ENERGY CURTAILMENT

Curtailment: Electric System

Overview

Electric curtailment is infrequent, and normally takes place only during extreme periods of cold weather. Electric curtailment may be initiated when a Stage 2 or 3 Energy Emergency is declared by Puget Sound Energy (PSE).

The PSE electric curtailment program is primarily a communications plan between Puget Sound Energy and its larger customers served under rate schedules with curtailment provisions. Curtailment contracts are complex and have variable factors relating to amounts of interruptible demand, hours of interruption, and advance notice requirements.

The decision to curtail electric load is made by Energy Trading. Energy Trading can elect to curtail specific customers under two conditions:

- For economic reasons when high market prices do not justify the purchase of sufficient power to meet estimated demand.
- For energy shortage reasons when energy trading cannot secure sufficient power to meet demand at any price.

Electric Rate Schedules with Curtailment Provisions

The following table explains the process by shedding load by curtailment:

Rate Schedule	Minimum Interruptible Demand
Schedule 38	300 kW per customer
Schedule 43	0.6 per sq. ft. of structure
Schedule 46	Entire facility
Schedule 48	Varies with customer
Schedule 93	Limited and varies with customer
Special Contract	Varies with customer

Curtailment Process

The following table explains the process of shedding load by curtailment:

Who	Does What
Director of Energy Trading	Determines curtailment is required Communicates to System Control (on-duty System Operations Supervisor and/or Emergency Planning Manager): • Customer class affected • Curtailment starting time • Curtailment duration
System Manager	Initiates notifications to the following listed departments for plan activation: • Major Accounts • Key Customer Services • Customer Access Center • Federal & State Regulations • Corporate Communications • First Response • Government and Community Relations Managers
Major Account Executives	Notify affected customers May utilize emergency response personnel assigned as “curtailment callers” depending on the size of the curtailment effort

If Customers Do Not Curtail

In the event customers who have been requested to curtail do not do so, then penalty provisions may be imposed by the Federal and State Regulation Department as stipulated in the various rate schedules. In addition, the customer may be disconnected, at the discretion of PSE.

Curtailment – Gas System

Overview

PSE's gas distribution system and gas supply resource portfolio is designed to meet the needs of firm customers. Interruptible service is made available at a lower rate as long as the distribution capacity and/or the contracted gas supply resources for our firm rate customers are not put at risk. A stipulation of the interruptible rate contract is the curtailment of interruptible gas use if in PSE's sole discretion their continued use of interruptible volumes will jeopardize continuous service to firm customers. Interruptible volume is defined as, "*Gas used in excess of the firm contracted amount as identified in such customers' service agreement*."

This section of the document is intended as a guideline for curtailment only and is not to be interpreted as rules. There may be other conditions where curtailment is required that are not covered in this document. This is a supplement to Puget Sound Energy's annual Cold Weather Action Plan. A curtailment in and of itself is not an emergency; however, an emergency may require curtailment for control of the situation.

Definitions

Supply Curtailment

PSE solely determines supply curtailment if the company's:

- Contracted gas supply and/or upstream transportation capacity is insufficient to meet the expected total demands of firm and interruptible sales customers, or
- Storage inventory levels are judged to be so low as to sufficiently compromise delivery and to reliably serve the expected demands of firm sales customers in future periods.

System Curtailment

PSE solely determines system curtailment if the company's:

- Distribution system or any portion thereof is insufficient to meet estimated requirements for all firm and interruptible sales and transportation service customers, or
- Partial or full curtailment is judged to be required to facilitate the repair or maintenance of the company's distribution system, or
- Manage operating conditions and pressures on the company's distribution system or any portion thereof.

Gas Service Curtailment Program

Gas supply curtailment typically takes place during cold weather or extreme conditions; however, may occur at any time. The procedures described in "Cold Weather" in this plan detail notification requirements, internal and external communications, and operational duties and responsibilities.

Guidelines

The decision to curtail is complicated and involves several of the key personnel groups. Anytime Cold Weather Action is activated, all key PSE personnel (listed above) must be prepared for curtailment.

Gas Control must maintain daily contact (at least) with the Gas Traders to keep informed of the anticipated supply situation.

If curtailment is deemed necessary, the Emergency Response Planning Engineer, Total Energy System Planning and the on-duty Manager Gas System Operations will be brought into the discussion. If the condition is supply related, the Gas Traders will be brought into the discussion. This is to be done at least daily as long as these conditions exist.

Scope of Curtailment The following describes responsibilities for various key personnel:

Who	Does What
Total Energy System Planning; Gas Control; Manager Gas System Operations	Determines curtailment is required. Communicates to Energy Measurement the extent of the curtailment.
If 0-3 Customers – Gas Control	Notifies affected customers. Maintains documentation. Forwards all records to Energy Measurement.
If 0 – 100 Customers – Energy Measurement	Notifies affected customers and maintains documentation. May utilize Major Account Representatives and/or Key Customer Services personnel to assist.
Over 100 Customers – Energy Measurement	Notifies affected customers utilizing emergency response personnel assigned as "curtailment callers". Works with Emergency Response Manager to dispatch additional personnel for assistance.

If Customers Do Not Curtail

In the event customers who have been requested to curtail do not do so, then penalty provisions may be imposed. Failure to comply with curtailment action may result in disconnection of service by PSE during the curtailment period. Energy Measurement will collect all data to assess penalties for unauthorized usage. Major Accounts and Key Customer Services personnel will work with customer with unauthorized usage to resolve penalties.

Key Personnel Responsibilities

Who	Does what
Customer Access Center	Forward all calls regarding curtailment to Energy Measurement, Major Accounts, or Gas Control.
Emergency Response Planning Engineer	During a curtailment event of more than three customers, work with the Manager, Gas System Operations, Gas Control, Emergency Response Manager and Total Energy System Planning. Establish parameters for reviewing the duration of the curtailment period.
Energy Measurement	Initiates calling to inform customers of curtailment and resumption of service. Maintains a database where curtailment data is available by • Name • Address • Emergency section • ID# Coordinates customer calling and provide assistance calling customers, ensure all interruptible customers are notified of curtailment and resumption of service, and maintain all records of customer contacts for penalty validation. Notifies meter reading of the need for, and timing of curtailment meter reading, or obtain meter readings via Cell-Net for AMR customers. Contacts the Customer Access Center to let them know a curtailment is in effect, and when it has ended. Notifies Total Energy System Planning of customer requests for limited or partial curtailment. Provides Chart Changers as required for emergency pressure checking and/or chart changing during a cold weather event. Forwards copies of Large Volume Metering billing charts, Electronic Volume Recorder data, and all System Pressure Recorder charts, to Gas Control, System Control and Protection and Total Energy System Planning for review where appropriate. Calculates consumption during curtailment period and notify Major Account and Key Customer Services of violations/penalties. Contacts all customers annually for the purpose of obtaining up-to-date phone numbers and contact information. Sends letters to interruptible customers notifying them that they are obligated to curtail and must maintain a back –up system. Trains PSE personnel for curtailment calling.

Key Personnel Responsibilities, Cont'd

Who	Does what
Energy Trading	Keep Gas Control informed about supply situation and available reserves. Immediately notify Gas Control of known or expected supply problems. Supply necessary gas pricing information on a daily basis to Energy Measurement for penalty calculation.
Gas Control	Notify affected customers as required. Monitor SCADA data and weather forecasts. Provide Cold Weather Action Forecasts. Estimate the 4-8 AM send-out and provide that information to all key personnel. Update voice mail message on the Cold Weather Action line for all key personnel. Assist with curtailment calling when workloads and staffing permit. Communicate with Total Energy System Planning regarding the projected need for curtailment.
Gas Operations Dispatch	Monitor customer service order data for possible low-pressure conditions. Forward all indications of low pressure to the GPSC, Total Energy System Planning and Gas Control. Maintain documentation of all possible low-pressure conditions and the related service calls.
Major Accounts and Key Customer Services	Contact customers as directed for interruption and resumption of interruptible service. Immediately notify Gas Control of known or expected supply problems. Periodically contact interruptible customers regarding curtailment preparedness. Immediately notify Gas Control and Total Energy System Planning if an interruptible customer is unprepared for curtailment or unable to curtail. Immediately notify Gas Control if an Interruptible or Transporting customer is planning a significant increase in consumption.
Director, Gas Operations	Notify the Director Operations of the need for and extent of curtailment. Verify Officer approval of a curtailment event, except in an emergency. Ensure First Response and Service Providers are notified of curtailment activity for potential emergency repairs/temporary reinforcement. Maintain contact with the Response Planning Engineer regarding status of the curtailment event.

Key Personnel Responsibilities, Cont'd

Who	Does what
Total Energy System Planning	Analyze forwarded copies of possible low-pressure conditions to determine if they are system problems. Prepare load studies that reflect forecast conditions, and store them for reference. Analyze cold weather action, SCADA and Pressure Recorder data, and customer service order data to determine effectiveness of curtailment, and recommend any additional action items. Estimate locations and flow levels/temperatures where curtailment may be required to assure service to firm customers. Review effectiveness of Cold Weather Actions and revise annual Plan as necessary.

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SECTION 9 – APPENDICES

Contract Management

Normal Business Function

Contract Management is responsible for facilitation of PSE's master service provider agreements with Quanta and Pilchuck. Additionally, Contract Services maintains contracts for local services such as, distribution crews, tree removal crews, flaggers, helicopters (for aerial patrols), etc. Contract Services routinely updates services agreements and, from October through April of each year, validates the availability of local contractor resources on a monthly basis. Following each event, Contract Services reviews storm-related billings submitted by contractors.

Emergency Response Function

When operating bases are engaged in significant electric outage restoration activities, contract managers are deployed to effected regions to ensure service provider resources are utilized in a manner that is consistent with the applicable contract. Contract managers may also be utilized to back-up first response supervisors.

Major restoration efforts require PSE to respond to significant numbers of incidents. PSE utilizes local service providers to augment available First Response resources in order to speed restoration. Contract administrators are utilized by the Emergency Operations Center (EOC) as Resource Coordinators and by the Gas Planning Strategy Center (GPSC) as service provider liaisons.

Emergency Response Roles

EOC Resource Coordinator

Contract Manager

Service Provider Management Liaison

Emergency Response Training

Emergency response orientation, EOC orientation (Resource Coordinator), GICS and GPSC operations

Emergency Response Location

Role	Location
Resource Coordinator	EOC
Contract Manager	Operating Base
Service Provider Management Liaison	GPSC

Activated By

Role	Activated By
Resource Coordinator	EOC Manager
Contract Manager	System Operations Supervisor
Service Provider Management Liaison	Emergency Response Manager

Corporate Communications

Normal Business Function	Corporate Communications is responsible for Puget Sound Energy's corporate messaging – both internally and externally: product or program promotions, customer billing messages, financial reports and special event messages. Corporate communications delivers messages through local television, radio, newsprint and corporate internet web site (www.pse.com).
Emergency Response Function	During major events, Corporate Communications assumes a media relations role within the Emergency Operations Center (EOC) and serves as a "central clearing house" for all event messages. The EOC media relations representative coordinates with the EOC manager to gather high-level information about the event from each of the impacted areas. The EOC's media relations representative also coordinates with the Customer Access Center to ensure messages provided to calling customers are consistent with information provided by local broadcast media. The media relations representative issues and updates media advisories to media organizations covering the event.
Emergency Response Roles	EOC Media Relations
Emergency Response Training	Emergency response orientation, EOC and GPSC orientation
Emergency Response Location	Emergency Operations Center
Activated By	EOC Manager or, Gas Duty Manager/System Operations Supervisor when EOC is not open.

Customer Access Center

Normal Business Function

The Customer Access Center (CAC) provides full customer service Monday-Friday from 7:30a-6:30p, and responds to calls for emergency services 24/7, including holidays.

The CAC utilizes approximately 150 representatives in shifts staggered to meet forecasted daily call volumes, which includes 30 representatives that work off-site from home. Additionally, customers may interact with PSE via e-mail, during normal business hours or automated self-service 24/7 via the Integrated Voice Response Unit (IVRU).

The CAC also maintains a Point Desk, a "one-call" 24/7 internal PSE contact point for communication with the Customer Access Center.

Emergency Response Function

Though outage calls may represent a high percentage of total calls, outages may not equally impact all parts of PSE's service area. Customers in less impacted service areas will continue to conduct regular routine business with PSE.

During major events, in order to provide additional staffing to meet higher call volumes resulting from outages and to continue to meet routine business needs, the CAC moves its customer service representatives (CSR's) and its' management team to daytime 12-hour rotating shifts. CSR's shifts are arranged to provide full-service coverage between approximately 5:00am and 9:00pm, with maximum staffing coverage for peak call periods. After-hours, non-CAC staff is utilized to respond to customer outage and emergency calls through the night, when call volumes are much lower.

CAC staff will remain on 12-hours shifts until outage calls have returned to more normal levels.

In addition to responding to customer outage calls, the CAC is instrumental in communicating the overall scope and character of each event as well as where our current efforts are relative to the typical phases of outage restoration. High-level event messaging is provided to help customers make decisions during the early phases of large outages, when specific circuit restoration information is not yet available in CLX.

How the Customer Access Center is Activated

The CAC can be activated for emergency events in one of three ways:

- By CAC management
- By the on-duty System Operations Supervisor
- By the EOC

Emergency Response Roles

To provide additional phone answering support, approximately 70 non-CAC employees have been identified and assigned CAC Call Taker emergency response roles. Individuals assigned to this role are generally co-located at the Bothell campus.

Emergency Response Location

Customer Access Center - Bothell

Bothell Emergency Center (BEC)

During Level 2 or 3 Emergency Events, (determined by Service Level, number of outages or customers impacted by the event) the Bothell Customer Service Management Team initiates the opening of BEC. BEC is comprised of several support teams for the purpose of managing the event to assure consistent messaging and that customer and operational needs are met. There are 7 support teams, a rotating Team Lead is assigned to each group and has the responsibility of providing specific support or functions.

The rotating roles of the BEC Teams are:

- Duty Supervisor
- Director
- Manager
- Staffing Team
- Communications Team
- Training Team
- Provisions Team
- IT Team

Emergency Response Training

When activated, CAC staff provides training to call-takers as they arrive. Hands-on instruction is provided in the use of CLX, Aspect phones and how to respond to customer outage calls.

Electric First Response Dispatch

Normal Business Function	Electric dispatchers receive routine / emergency service requests and subsequently assign a PSE first responder (serviceman) to investigate or resolve. During normal business hours and during normal conditions, electric dispatchers are co-located at Eastside System Operations (ESO), where all service-work company-wide is reviewed / assigned and dispatched.
Emergency Response Function	When outage conditions begin to escalate, electric dispatcher(s) are physically relocated to operating base(s) that are responsible for restoring service to the impacted area. Once the dispatcher is onsite locally, CLX outage reports and related service orders for the effected area are electronically rerouted to the operating base, allowing local review, prioritization and assignment. A back-up dispatcher may be utilized to dispatch while the dispatcher is in-transit to the location, or during off-peak hours, or at bases where the volume of dispatch work is lower. Until the storm board staff is fully mobilized, the dispatcher may review and directly assign work to PSE's servicemen. However, as the operating base staff begins to assume responsibility for coordination of all resources, responsibility for reviewing and assigning work to the servicemen will roll to the storm board coordinator.
Emergency Response Roles	PSE dispatcher or Back-up Dispatcher
Emergency Response Training	Emergency response orientation, CLX outage overview, operating base orientation.
Emergency Response Location	Operating base
Activated By	System Operations Supervisor or EFR Supervisor

Electric First Response Operations

Normal Business Function	Electric First Response (EFR) is responsible for all routine service requests where a qualified electrical worker is required to respond. EFR also provides 'round-the-clock' investigation of outages or other electrical emergencies. First responders (servicemen) assess and resolve most problems that do not require a crew to repair.
Emergency Response Function	As outages begin to escalate, EFR focuses on public safety issues, isolation of system damage and switching to restore service. EFR supervisors play a key role in the transition of restoration efforts to local teams by coordinating staffing at operating bases with Quanta management.
Emergency Response Roles	EFR supervisors team with Quanta management to mobilize resources and orchestrate overall response efforts. EFR servicemen investigate, assess, isolate and restore service with a focus on ensuring public safety. EFR engineers are utilized for storm board coordination, system analysis, damage assessment or other functions. EFR operating clerks are utilized as CLX Specialists
Emergency Response Training	Emergency response orientation; CLX Specialist training
Emergency Response Location	Operating Base
Activated By	EFR supervisors are contacted by the System Operations Supervisor Local EFR staff is contacted by the EFR supervisor

Electric System Operations

Normal Business Function	Electric System Operations is responsible for the safe operation of the electric distribution system. This includes monitoring the electrical performance of the distribution system as well as coordinating electrical switching and (safety) clearances for all system maintenance, construction and outage repair. After normal business hours, System Operations assumes the additional responsibilities of Electric First Response Dispatch and directly dispatches servicemen as problems arise. After normal business hours, system operators also provide routine updates on customer and distribution outages. The system supervisor is responsible for continually monitoring system-wide weather conditions and regional outage activity. The system supervisor is responsible for initiating the emergency response plan.
Emergency Response Function	As distribution outages begin to increase, System Operations can become quickly overwhelmed by the rapidly increasing need for resources (servicemen, crews) in addition to the increasing need for distribution system analysis, switching instructions and electrical clearances. In anticipation of escalating outages, the system supervisor will collaborate with Quanta management to open area operating base(s), which transitions the oversight of restoration efforts from System Operations to local team(s).
Emergency Response Roles	Continual monitoring of current conditions and system performance. Activation of emergency response plan.
Emergency Response Training	Emergency response orientation
Emergency Response Location	System Operations
Activated By	System Operations Supervisor

Fleet Services

Normal Business Function	Fleet facilitates the repair and maintenance of all internal Company fleet assets, providing a single point of contact, by way of a toll-free number. In addition, Fleet processes vehicle-related invoices, determines proper fleet mixes and coordinates the acquisition and retirement of all fleet assets. Fleet is also responsible for ensuring compliance with guidelines for DOT, ANSI and other government entities.
Emergency Response Function	During emergency events, the Fleet department will facilitate repair and maintenance of all responding vehicles. Response expectations have been established for Fleet’s vendors, and will place vendors on-call when an event is anticipated or underway. Vendors will be present, in the field, where they are needed during prolonged events.
Emergency Response Roles	Fleet maintenance coordination
Emergency Response Training	Emergency response orientation
Emergency Response Location	Operating base
Activated By	EFR Supervisor or, System Operations Supervisor

Government and Community Relations

Normal Business Function	Government and Community Relations develops and maintains business relationships with local community leadership. Partnering with local leaders is fundamental to garnering community support for implementation of PSE's business initiatives. Among other benefits, strong local relationships allow PSE to reduce the overall timeline and cost of system projects, ultimately enhancing the quality of service provided to PSE's customers. Government and Community Relations provides technical assistance on public policy and government affairs to business units as needed. Corporate Relations Managers participate in setting the strategic direction for PSE's public policy strategy and also oversee the implementation of specific public policy programs, supporting the Company's mission, goals and objectives.
Emergency Response Function	During significant events, Government and Community Relations Managers, Municipal Liaison Managers and Municipal Construction Planners assume a role of Communications Coordinator at each of the operating bases involved in outage restoration. Communications Coordinators serve as a vital communications path to local government officials and help to identify critical infrastructure that may be off-line locally. Communications Coordinators collaborate with the EOC's Media Relations representative to ensure uniform messaging is provided to local government, media and other customers.
Emergency Response Roles	Communications Coordinator
Emergency Response Training	Emergency response orientation
Emergency Response Location	Operating bases or Gas Planning and Strategy Center (GPSC)
Activated By	EFR Supervisor or Emergency Response Manager

Major Accounts / Business Accounts Services

Normal Business Function	Major Accounts and Business Account Services provide account management and segment support to Puget Sound Energy's largest commercial and industrial customers. Major Accounts focuses on PSE's largest customers, providing a single point of contact for their utility needs. Business Account Services targets the mid-to-large commercial and industrial customers with an eye toward segment-management and one-to-many account support. Market Managers handle escalated and complex issue resolution, outbound communications and education for assigned business segments.
Emergency Response Function	During significant events, Major and Business Accounts Services employees serve in the role of EOC Major Accounts Representative. The EOC Major Accounts Representative provides an important information gateway to certain commercial and industrial customers such as, schools, hospitals, grocery stores, refineries or manufacturers. The EOC Major Accounts Representative tracks outages effecting commercial/industrial customers and provide frequent informational updates, helping business customers to make important operational decisions. The Major Accounts Representative is also the customer's point of contact during curtailment activities.
Emergency Response Roles	EOC Major Accounts Representative
Emergency Response Training	Emergency response orientation; EOC orientation
Emergency Response Location	Emergency Operations Center (EOC) or Gas Planning and Strategy Center (GPSC)
Activated By	EOC Manager or System Supervisor if EOC is not open.

Materials Distribution and Planning

Normal Business Function	To provide materials, goods and service to support NCC, Generation, Communication, Substation and T&D electric/gas construction and maintenance.
Emergency Response Function	To supply and transport materials to support emergency restoration during an emergency event. Plan and forecast emergency material replenishment.
Emergency Response Roles	Material Distribution and Planning (MDP) - Duty Supervisor assesses level of emergency event and coordinates notification of MDP management staff, warehousers, operating clerks, and drayage drivers **Level 0 – Normal** Operating base storeroom supplies materials for emergency event. MDP duty supervisor / Central Stores is on stand-by for any material shortage. **Level 1 – Regiona**l Operating bases are responding to an emergency event at local level - MDP duty supervisor coordinates emergency callout to deliver needed material. **Level 2 – Significant** Two or more operating bases are responding to an emergency event – Central Stores open operation with limited staff **Level 3 – Major** Most or all operating bases areas are open to respond to a storm event – Central Stores geared up for 24 hour operation and implement emergency personnel job rotation.
Emergency Response Training	Emergency response orientation Review with staff Material Distribution and Planning emergency response plan in the month of September.
Emergency Response Location	Normal or alternate work locations Central Stores South King Facility in Kent. Alternate location: Any PSE operated storerooms
Activated By	System Operations Supervisor, EOC Manager, Emergency Response Manager, MDP Duty Supervisor or Manager of Material Distribution and Planning.

Purchasing

Normal Business Function

The Purchasing Department's normal business function is to procure services, materials and equipment for PSE's internal operations. Purchasing establishes long-term contracts to ensure adequate services or supplies and utilizes strategic sourcing processes. Purchasing also evaluates supplier performance to ensure quality products are acquired.

Emergency Response Function

During significant events, Purchasing staff is available 24 by 7 to respond to any need for material, equipment or services in support of timely response and recovery of PSE's energy systems.

Purchasing representatives maintain a business continuity plan to ensure that procurement functions can continue should their normal work environment become non-operational. Each buyer maintains copies of the Purchasing Department's emergency manual at their desk and an off-site location. The manual contains important contact and contract information for all major electric and gas suppliers as well as any applicable joint response plans. The document also details back-up plans to be used in the event normal communications or information systems are unavailable.

During significant events, Purchasing staff receives updates from Materials Management who tracks the inventory outflow from warehouses and identifies additional materials which need to be acquired.

Emergency Response Roles

With input from key PSE personnel monitoring possible or current storm/emergency events, the Manager Purchasing coordinates notification to Purchasing staff and storm materials suppliers. Manager Purchasing and/or staff coordinates procurement of storm materials as needed with Materials Management personnel.

Level 0 – Purchasing staff on call and available 24/7 to procure storm materials and services. Key storm materials suppliers informed of emergency event and possible ordering.

Level 1 – Two or more Service Centers are responding to an emergency event - Manager Purchasing informs staff and storm materials suppliers and distributors of emergency event. Staff assigned for non-business hour coverage as appropriate.

Level 2 – Two regional areas are responding to an emergency event – Similar to Level II response above with need for elevated response communicated to storm materials suppliers and distributors.

Level 3 – All areas are open to respond to a storm event – Purchasing staff scheduled for 24/7 coverage. Storm materials suppliers instructed to provide 24/7 coverage. Suppliers may be asked to have other customers release non-critical production time if needed or arrange special production runs for PSE. Distributors may need to obtain materials from additional sources. Purchasing also prepares for subsequent storm events.

Emergency Response Training

Prior to storm season, Purchasing Department's Emergency Response Manual is reviewed and updated as needed. The entire department meets to ensure roles and responsibilities are understood. Training is also held for Lodging Coordinators assigned to various regions of the Company's service territory in coordination with PSE's travel agent.

Emergency Response Location

Generally, Purchasing staff performs storm/emergency duties from the PSE building. However, Purchasing staff is equipped and prepared to conduct business from alternate locations, including their home.

Activated By

System Operations Supervisor, EOC Manager, Manager Purchasing or request for storm restoration materials from Material Management personnel.

Substation Operations

Normal Business Function	Substation Operations is responsible for the construction of new substations and the inspection, maintenance and operation of nearly 350 existing transmission and distribution substations.
Emergency Response Function	During a significant event, Substation Operation's personnel are utilized initially to restore PSE's substations to normal operation. Substation inspectors and wiremen are utilized primarily to perform substation switching. Additional substation personnel are mobilized when there is physical damage to substations. Depending on the operational impact to substations, a portion of Substation Operation's personnel may be freed-up to perform other restoration functions such as, damage assessment or crew coordination.
Emergency Response Roles	Normal duties – extended hours Contract Crew Coordinator, Damage Assessor, Driver
Emergency Response Training	Contract Crew Coordinator / Damage Assessor – Safety Overview
Emergency Response Location	Operating base(s) / field locations
Activated By	System Operations Supervisor, Substation Duty Supervisor, Manager of Substations.

GLOSSARY

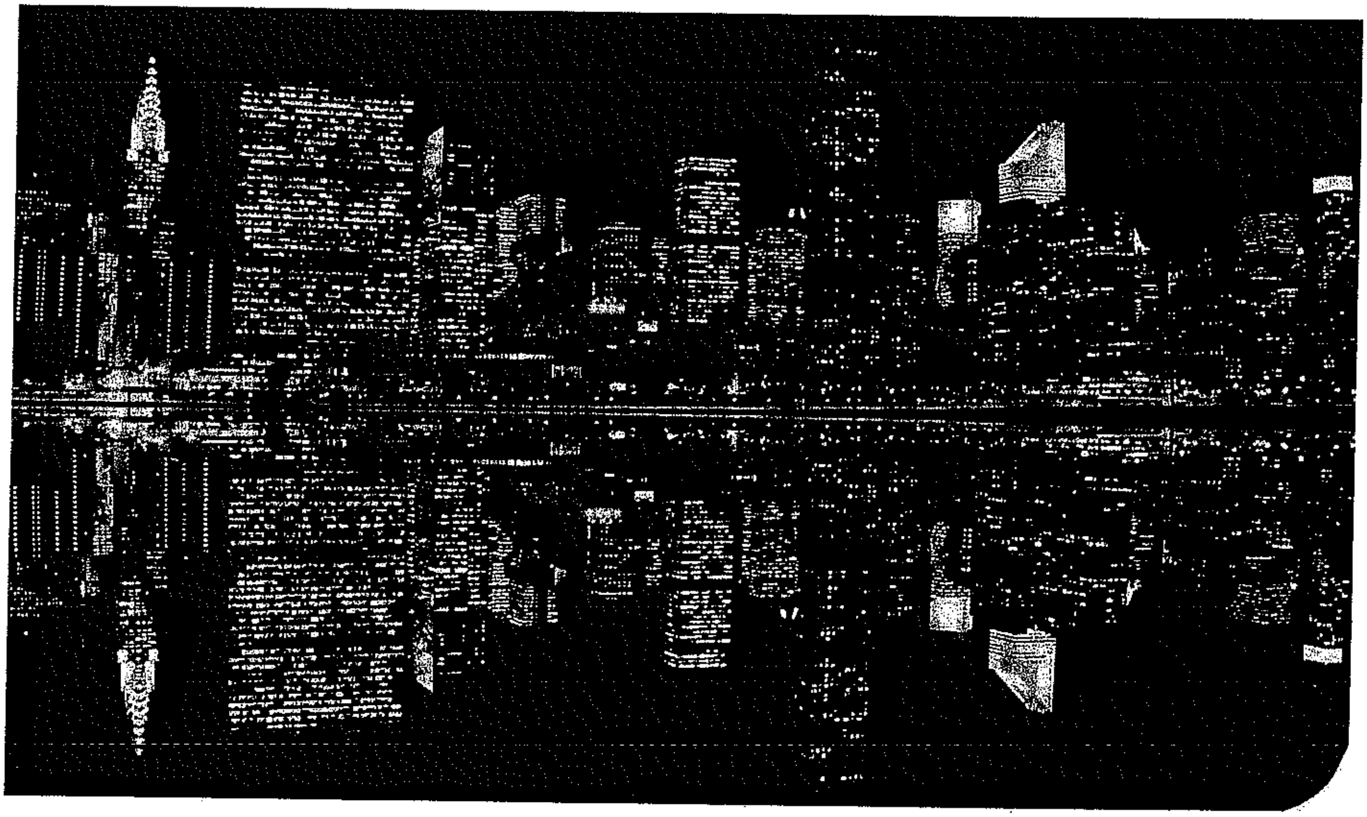
Term	Definition
AGA	American Gas Association
AMR	Automated Meter Reading
Callback	Outbound calls to customers to verify service has been restored
CFH	Cubic feet per hour
CNG	Compressed Natural Gas
Cold Weather Actions	When cold weather conditions (around 32 degrees Fahrenheit) are forecasted, and multiple customers in the same area (such as a residential block) report outages or equipment inconsistency. The condition may affect only one area. System modeling may be required. Adjacent operating areas may be called upon to assist to respond to the emergency.
Curtailment	Supply and/or system conditions exist that require customers to limit their consumption of our energy products. Interruption may take place after advance notice, following the provisions of a particular rate schedule; without communication, following state regulation; or without notice, following internal operating procedures.
EEI	Edison Electric Institute
EFR / GFR	Electric First Response / Gas First Response
Electric event (major)	5 percent or more electric customers are without service
EOC	Emergency Operations Center
ESO	Eastside System Operations
ESIC	Executive Systems Integrity Committee
Foreign crew	A crew from out of the area that does not normally work on PSE’s system. May be a mutual assistance crew from another utility, contract crew from another State, etc.
Gas event (major)	Twenty-five or more customers lose gas service.
Gas Facility Failure	Twenty-five or more customers experience and report outages or equipment inconsistencies due to a system failure; or, a failure occurs that requires system modeling and impacts less than 25 customers. The condition may affect only one area. Adjacent operating areas, service providers, and/or local contractors may be called upon to assist in restoration efforts.

Term	Definition
GPSC	Gas Planning and Strategy Center
LNG	Liquefied Natural Gas
NERC	North American Electric Reliability Corporation
NWPP	Northwest Power Pool
RTU	Remote Telemetry Unit
SC&P	System Control & Protection
SCADA	Supervisory Control and Data Acquisition
Substation	A transmission or distribution station for where electricity voltage is stepped-down to a lower voltage.
WEI	Western Energy Institute
WRMAA	Western Region Mutual Assistance Agreement
WECC	Western Electric Coordinating Council
WUTC	Washington Utilities and Transportation Commission

EXHIBIT F

Damage Assessment Practices

Damage Assessment Leading Practice Survey



Puget Sound Energy
May 9, 2008

KEMA

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KEMA

Executive Summary

KEMA was engaged by Puget Sound Energy (PSE) to conduct a survey of business practices related to storm damage assessment to address conclusions in KEMA's July 2007 report and PSE's own post-storm analysis. The primary objective of this project was to better understand industry "leading practices" to improve damage assessment effectiveness. Secondary goals included support for associated training programs, organizational models, staffing deployment plans and management of work activities.

A questionnaire was developed and 22 utilities were identified and contacted to determine their interest in participation. Of these, the following ten utilities participated:

- [redacted]

The survey results were assessed based on a number of factors, including:

- The respondent company's environment relative to PSE
- Organizational approaches used for damage assessment
- Damage assessor's skills, qualifications and training
- Work methods and approaches for conducting damage assessments
- Support and technologies deployed

From this analysis, KEMA identified the following key findings and leading practices:

- Open different hierarchies of Incident Command Centers in advance based upon preset conditions - with field forces on alert
- Draw principal damage assessors from local resources who have direct experience and knowledge associated with field construction; support them with kits and training
- Determine resource levels based upon the severity of the event

- Predict an initial global estimated restoration timeframe based upon a model driven by relevant estimating factors – independent of damage assessment
- Develop detailed damage assessments during the initial assessment process (i.e., do not conduct an initial high-level drive-by followed by a detailed assessment)
- Develop localized estimated restoration timeframes based on job schedules related to specific circuit repairs and associated customers
- Utilize an Outage Management System and mobile data terminals

KEMA also concluded that planning for earthquakes among the surveyed utilities was generally inadequate. Utilities in earthquake prone areas must plan for this specific type of event because is differs significantly from above ground storm event damage and restoration efforts.

1. Introduction

This section provides a general overview of the background, goals and objectives for this project, including a summary of the approach that was taken for the analysis and the companies that were involved in the survey.

1.1 Project Background

KEMA was engaged by Puget Sound Energy (PSE) to conduct a survey of business practices related to storm damage assessment. This effort was the direct result of KEMA's conclusions and recommendations around PSE's damage assessment processes and staffing that were included in the July 2007 report titled, "Windstorm of December 14-15, 2006," and results from PSE's own post-storm analysis. The report concluded the following statements with respect to damage assessment:

- "There is a formal damage assessment process, but it did not scale sufficiently to provide adequate and timely information to management during the December 14-15 storm."
- "PSE has a formal damage assessor training program, but it did not provide the number of qualified assessors required for an event of this magnitude."
- "PSE conducted damage assessment training just prior to the beginning of the storm season but attendance was low."
- "Crew foremen provide direct feedback on the extent of repairs required and an estimated completion time; however, this completion time may not be the same as restoration time."

PSE initiated this damage assessment leading practices survey to address the above findings, understand industry leading practices in this critical area, and determine the appropriate future actions.

1.2 Project Objectives

The primary objective of the survey was to better understand industry "leading practices" in damage assessment by interviewing select electric utilities relative to how they are organized to perform significant storm damage assessments, the business practices they execute, their communications approach utilized during the assessment, and the technology and tools deployed.

PSE's primary goal was to improve damage assessment effectiveness during major storm events. Secondary goals included support for associated training programs, organizational models, staffing deployment plans and management of work activities.

1.3 Approach

KEMA's approach to conducting the survey and documenting the results and findings included the following activities:

- A questionnaire was developed in conjunction with PSE to cover key areas of interest and specific issues. The questions are included in Appendix A.
- Participation in the survey was solicited from the following 22 utilities:

[redacted]	[redacted]

- Of the 22 utilities contacted to determine their interest in participating in the survey, the following ten agreed to participate:

[redacted]

[redacted]

- Interviews were conducted and survey response information was collected. The participant list for these ten companies with contact information is included in Appendix B.

- The survey response data was compiled into an Access database for analysis by company and by question. These reports are included in Appendices C and D.

- The survey responses were analyzed with regards to:

  - Company environment relative to PSE
  - Organizational approaches used for damage assessment
  - Resources, skills, qualifications and training
  - Work methods utilized for conducting damage assessment activities
  - Technologies and tools deployed

- Based on this analysis, KEMA identified and documented key findings.

- Leading practices were identified based upon these findings and KEMA's industry knowledge and experience.

- This final report was developed to document survey results, findings, analysis and conclusions.

2. Summary of Survey Responses

This section summarizes the survey response information that was received. The actual responses are contained in the appendices. The next section summarizes the key findings from this information and KEMA's assessment of leading practices.

The survey questionnaire was structured to capture information about each company and their practices related to damage assessment. Major categories of information included organization, resources, work methods and technology.

Of the ten respondents, six were interviewed over the telephone and the questionnaire completed interactively. The remaining four preferred to complete the questionnaire on their own.

As questionnaire responses were completed, results were entered into an Access database for summary and analysis. Two different formats of summary reports were produced: 1) Damage Assessment Survey Sorted by Question - Appendix D; 2) Damage Assessment Survey Sorted by Participant - Appendix C.

2.1 Company Comparisons

To provide a context for evaluation, the companies were compared to PSE with regards to size, service territory characteristics, customer density, types and frequency of storms. The following map illustrates the service territories of the utilities that responded:

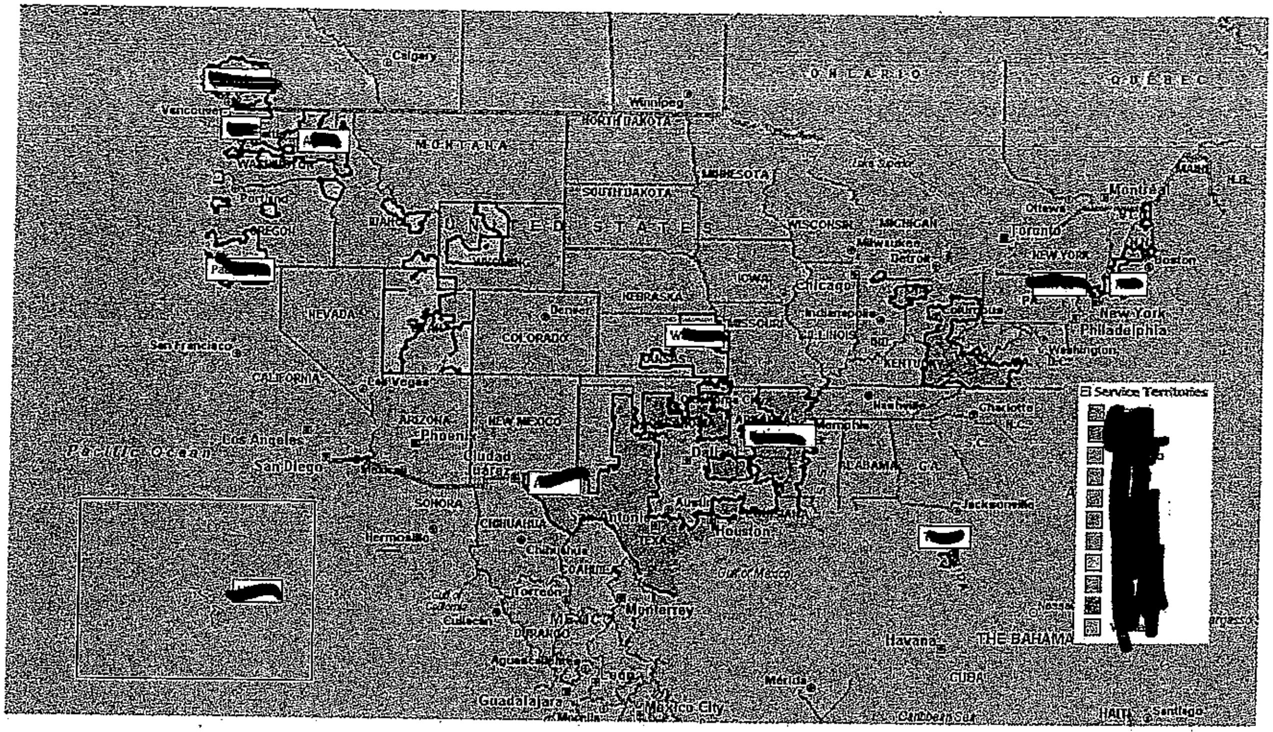

Exhibit 2-1: Service Territories

2.1.1 Size Comparisons

The surveyed utilities range from small (less than 300,000 customers) in a single contiguous service territory to very large (over 5,000,000 customers) in a ten state territory encompassing almost 200,000 square miles. Despite this wide variation in service size, there were common factors as to how these utilities organize for damage assessment, the approach and methods used, and data collected.

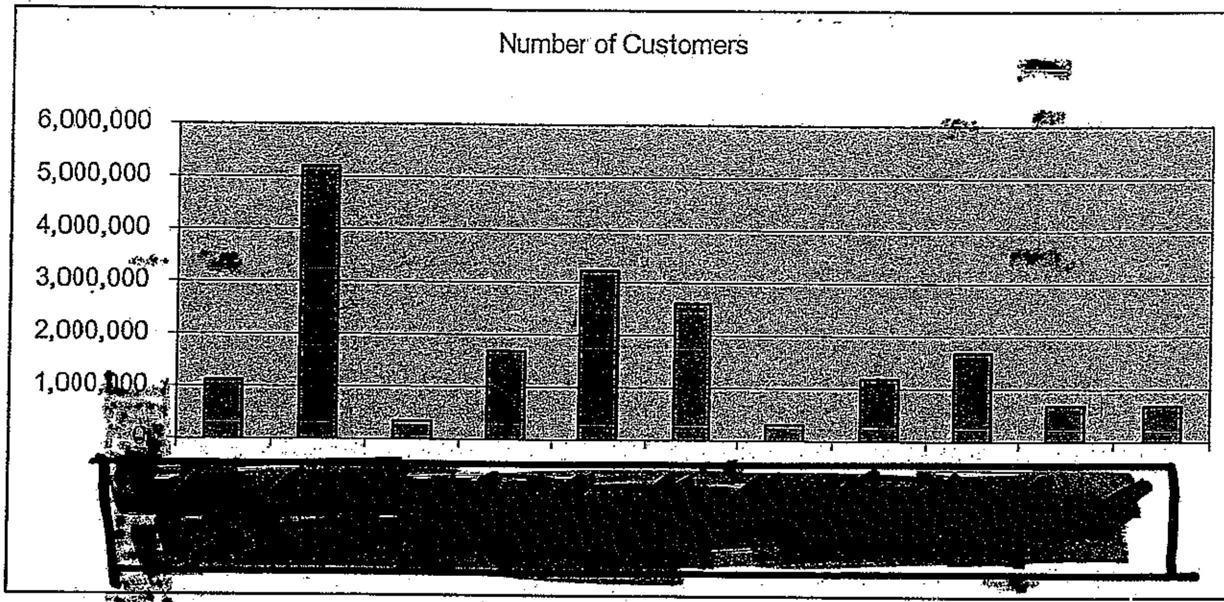

Exhibit 2-2: Company Size Comparison

2.1.2 Customer Demographic Comparisons

The number of customers a utility has, the geographic location of these customers, and the type of customers served seem to have little effect on how companies approach and manage storm events. There are common threads as to how the utility performs damage assessment and the use of data collected for the restoration efforts; large, multi-state utilities simply breakdown service territories into logical regions with local operations and management. We suspect that this is a pre-merger carry over characteristic where the former utility's operating structure remained intact.

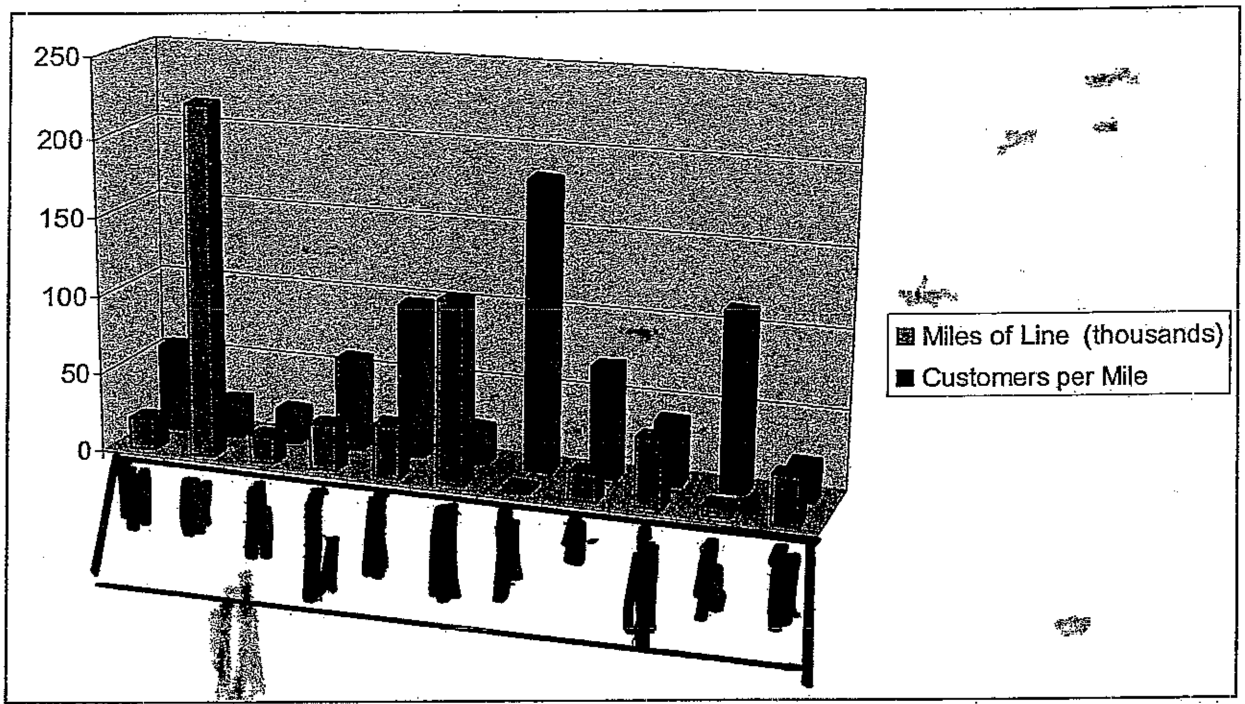

Exhibit 2-3: Company Demographic Comparison

2.1.3 Storm Types

The surveyed companies provide a cross section of utilities across the country and the resulting storm types are representative of this fact. Most utilities surveyed experienced similar storm events to PSE, including wind, rain, snow, and flooding. The following map is a summary of the types and costs of storms that impact each utility's service area based upon information provided by NOAA. The costs are normalized to the year 1999 and aggregate from 1955 – 2006.

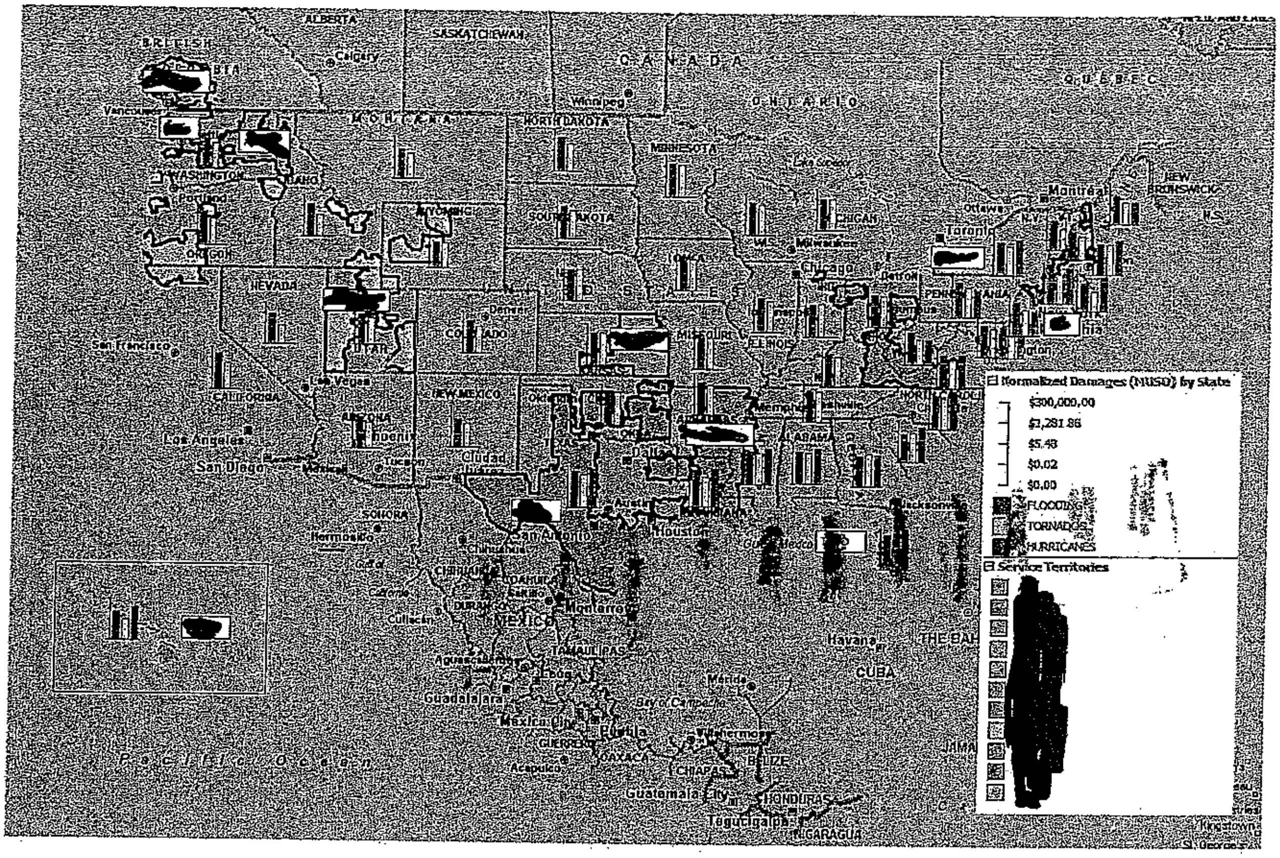

Exhibit 2-4: Storm Cost Comparison Map

2.1.4 IT Systems Support

There was no correlation to the size of the utility versus the information technology systems available to help with forecasting, damage assessment and restoration planning. Most utilities try to leverage technology for damage assessment, to determine restoration estimates, and to manage restoration work activities. These technologies include outage management systems, geographic information systems, mobile workforce management systems, mobile data terminals and applications specifically developed for forecasting and managing damage assessments. They also range from the use of in-house developed systems to commercial off-the-shelf packages.

2.2 Organization

Several survey questions were related to the organization for damage assessment under normal conditions and under storm event conditions. Other questions focused on the use and operations of an Emergency Operations Center (EOC) or Incident Command Center (ICC). Organization models were looked at for normal event damage assessments and for major storm event conditions. The use of an EOC or ICC is described and whether the utility has pre-defined criteria for activating the EOC/ICC.

2.2.1 Organization Model - Normal

For most respondents, daily event management included regularly assigned damage assessors located at the lowest organization field office, generally where distribution crews are located. Ninety percent of the respondents have field engineers located at their field operating centers. Only one respondent reported having a centralized field engineering unit. These area or field offices have personnel who have regular assignments as planners, designers or field engineers, but who also perform damage assessments as part of their jobs. They are skilled in knowing the distribution system within their assigned location. When performing damage assessments, they continue to work for their regular supervisor but report findings to the dispatch office.

System or distribution dispatch appears to be the coordinating body for damage assessments and the assignment of restoration crews. In one case, the company used the incident command structure down to the person in the field, dependent on the size of the event.

2.2.2 Organization Model – Storm Condition

For major events, all organizations open an Emergency Operations Center (EOC) or Incident Command Center (ICC). Several of the utilities followed the incident command system approach specified by the Department of Homeland Security. Other utilities used a modified approach to this system. With the EOC/ICC open, the regular damage assessors still report directly to local area management. A local damage assessment coordinator is established at the field office level who communicates directly to the EOC/ICC. No utility surveyed has the EOC/ICC directly manage damage assessors in the field, even during major storm events. One primary EOC/ICC function is to provide support to operating areas.

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2.2.3 EOC / ICC

Most utilities surveyed have pre-defined criteria for opening the EOC/ICC and the criteria is generally well understood in the organization. Some companies have specifically defined levels for different event conditions and the level at which the EOC/ICC is activated. Several utilities have contract meteorologists or use a weather service to make pre-event predictions and plans. A couple of the utilities use an estimating model to make pre-event plans.

Local (area, regional) management know exactly their role and responsibilities during major storm events versus the functions and responsibilities of the EOC/ICC. The EOC/ICC consolidates field office reports and data, provides operating area support as needed, and serves to provide consistent communications within the company and to external agencies. The EOC/ICC coordinates damage assessment activities that cross the utility's operating regions.

Most utilities stated that they have specifically assigned roles for EOC/ICC members, including media relations, crew comfort coordinator, materials coordinator, vegetation management coordinator, key accounts coordinator and IT support. These members in turn communicate to others within the company and with external organizations. One utility has a representative from the State EOC as a member of the utility's EOC who in turn coordinates activities at the State level. The utility media representative in the EOC communicates with public media to provide regular and consistent messages.

2.2.4 Reporting Structures

The individual identified for either the EOC manager's role or the incident commander (IC) is generally a senior, experienced manager or executive. Incident commanders must receive special training to obtain this title, where as the EOC manager will have achieved a certain management level within the company.

There isn't a clear consensus on the use of a coordinator, other than to say that 50% of the respondents have a defined position within the emergency response organization. Companies experiencing more events tend to have more formally defined positions.

Five of the respondents do not have a unique position identified for managing the assessors, but appear to leave these responsibilities to the local manager. The remaining respondents use a variety of titles to identify this role.

There isn't a clear consensus on the span of control, with numbers ranging from 5:1 to 30:1. The utilities that follow the incident command system approach reported a similar 5:1 span of control, which reflects these guidelines.

There does seem to be a correlation between the size of the event and the size of the company to the span of control. This may in part be due to the level of activity a company experiences annually.

Assignment of damage assessors can range from select personnel responsible for managing operations centers to EOC personnel. The common denominator is that the assigning personnel have extensive system experience.

While there is some diversity as to the reporting relationship, the majority of responders still put that responsibility at the local level and report through a hierarchy to the EOC/ICC.

2.3 Communications

Communications follows formal chain of command protocols. Either in the ICC or EOC model, communications moves from the field through the local responsible manager up to the ICC or EOC management. ICC or EOC management appears to control all out-bound messaging to the various public audiences. For the EOC/ICC itself, physical communications media and methods include telephone, radio, email and runners.

The question on communications support and coverage from the office or EOC/ICC to the field was answered in one of two ways depending on how it was interpreted; either as the physical mode of communications or the channels used to manage and gather damage assessors' information. Those responding to the technical interpretation indicated that multiple modes can be employed with the emphasis on company radios and cell phones. Those answering the question as a channel, indicated that the damage assessors report in to local bases, who in turn report data and information into the EOC\ICC.

Radios continue to be the primarily means of communication between the field and the operating centers with cell phone for back up. The use of mobile data terminals (MDT) is growing with 50% of the respondents using this technology already. Typically, an MDT is found in the first responders' vehicles and moving toward the line trucks to manage work orders. The advantage of the MDT is in its ability to receive work orders, graphic maps and drawings, and other information electronically for damage assessors in the field.

The vast majority of responders are making use of cell phones to communicate with the different field units. There is, however, a question of cell phone coverage availability during major storm events.

During restoration efforts, multiple forms of communications are used to deliver and receive critical information from the field. Paper orders, material requirements and damage assessments are still employed.

All but one respondent indicated they have a formal means for capturing and managing information received from public safety and other external public organizations. These tend to be line down reports. The person who acts as the contact point for a particular group depends on the organization type. There are formal processes for handling these calls, which vary with the specific company, but all have a means to ensure the information is captured and integrated into the main stream of outage information. Generally, the information finds its way into the main stream of outage information the utilities use for assigning crews. This communication can be facilitated by direct formal contacts with municipalities and county EOCs. Several utilities require a follow-up by their personnel to ensure the validity of the report.

2.4 Damage Assessment Resources

One major goal of the survey effort was to gain an understanding of the resource issues faced by other companies – including numbers of resources, skills, training and support. Several questions in the survey were targeted at this issue.

2.4.1 Resource Pool

The majority of companies draw their principal damage assessors from local districts. Local knowledge of the distribution system appears to be the principal driver for this decision. These regularly assigned damage assessors' primary jobs include planning, design and field engineering. Only one utility appeared to draw damage assessors from a central location, but that may be due in part to the configuration of the service territory. If the event is large enough, it appeared that management would seek out other technical individuals to support the core cadre of damage assessors.

All but one company would supplement the primary damage assessors with resources from other areas with in the company. Specifically, the respondents reported drawing personnel to perform damage assessment from central engineering, linemen, transmission and substation engineering. Several reported the practice of using a non-technical person as the driver in their two-person damage assessor model.

Four respondents indicated they use outside contractors on a limited basis for damage assessment. They reported have had varying success with the use of contract damage assessors. They generally have to be paired with an experienced utility crew member who knows the system.

2.4.2 Number of Damage Assessors

The number of damage assessor teams deployed by the respondent companies did not correlate to the size or density of the company – as illustrated in the charts below.

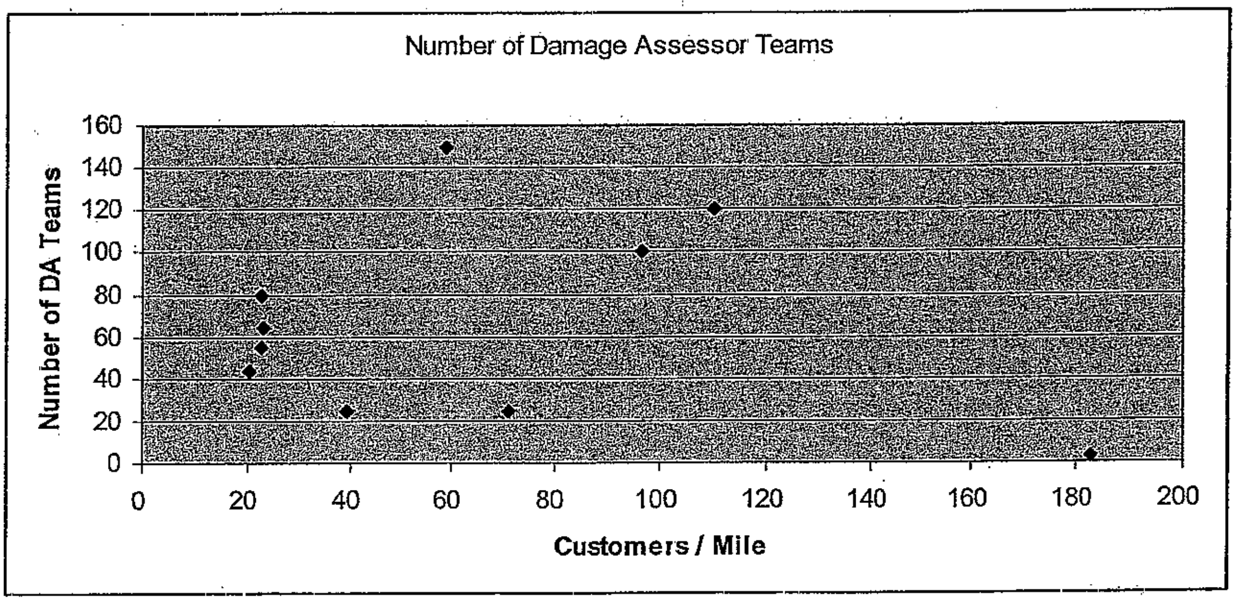

Exhibit 2-5: Customer Density Analysis

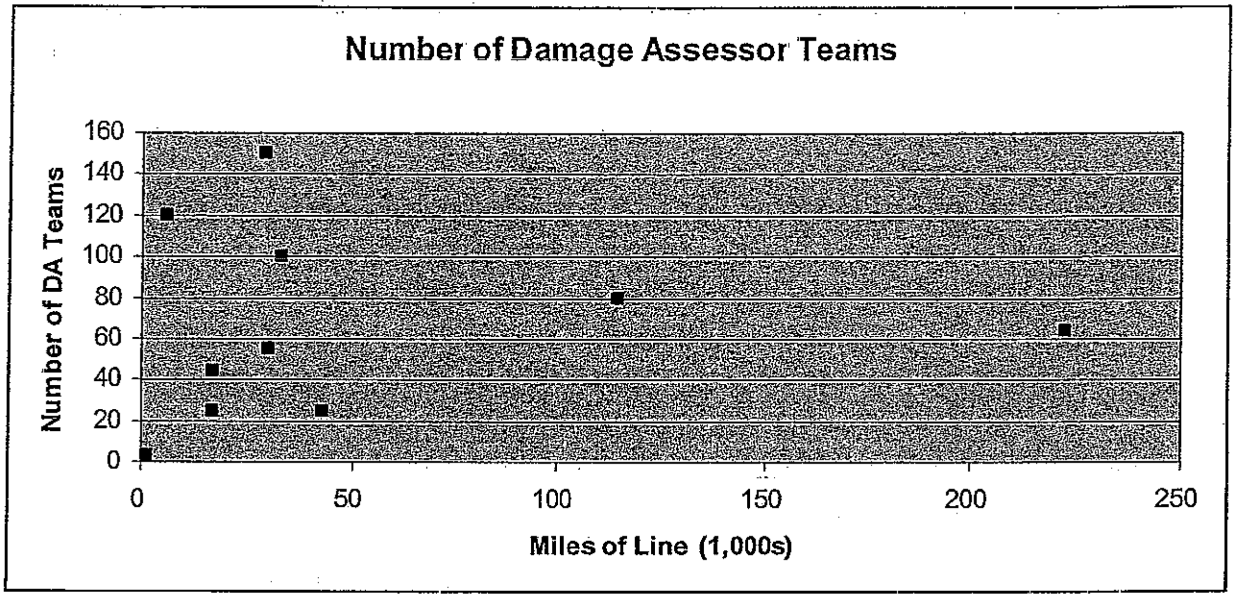

Exhibit 2-6: Line Mile Analysis

One company calculated the number of damage assessors needed by the number of circuits they must patrol and the intensity of the event. Several other respondents use the severity of the event as a gauge, and many of these utilities also use a model to help determine the number of damage assessors and their associated scope of work. For example, a utility in a hurricane prone area uses the following model based upon the category of the hurricane:

- Category 1: One assessor per three circuits (which allows the company to patrol the entire system with internal resources in a three-day period
- Category 2: One assessor per 2.5 circuits
- Category 3: One assessor per two circuits
- Categories 4/5: One assessor per circuit

A couple of respondents allow the on-area ground managers determine the needs based on damage.

Overwhelmingly, the respondents indicated that the limit on the number of deployed assessors is impacted primarily by skills and training. This indicated that the majority of respondents look for specific skill sets and provide training to enhance the assessor's abilities.

2.4.3 Training

Most respondents believe training to be an integral part of the damage assessor requirements. Training ranges from hands-on experience to formal training programs which may include design/construction training, table top exercises, in-house courses focusing on system familiarization, mock storm exercises, and safety and hazard training. Several companies require this training annually.

Formal training on safety in the field, hazard assessment and damage assessment is typically supplemented by on-the-job training. This formal training supplements their regular field and facility knowledge of the operating area to enable them to perform damage assessments. Most respondents indicated that they have no formal training program for staff members who are called to be damage assessors during significant storm events. They tend to be experienced former field personnel who have strong knowledge of the distribution system, but still would benefit from damage assessment training and refresher courses.

The training content appears to vary widely with no discernable pattern for the variation. One company has automated the damage assessment record, and is in the process of training assessors in its proper use. The cycle of training varied from just prior to storm season to every one to two years. Most utilities noted that they needed to work on better formalizing damage assessment training for regular damage assessors and for staff members who may be called on damage assessment assignments.

2.4.4 Preparation and Support

Utilities surveyed provide damage assessors with kits that include safety equipment, first aid items, circuit maps, drawings and street maps, and various other items.

Companies also provide "Crew Guides" to their foreign crews for support, logistics and communications purposes. One company reported that if outside damage assessors are required, they provide them with training.

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2.5 Work Methods

Responses to questions regarding damage assessor work hours, method for forecasting effects of pre-events, damage assessment methods and data gathered are summarize in this section.

2.5.1 Hours

In general, damage assessors work single 8-hour shifts for normal incidents, but may stay at the site until restoration is completed, extending the 8-hour shifts. Under major storm conditions, the utilities typically work damage assessors two shifts, up to 16-hours. However, not all of the hours are in the field; they may have several hours in the office for paperwork.

Those companies that regularly experience significant events tend to work their crews during daylight hours. The majority of companies responding report that they normally work one or two shifts. One indicated that they work damage assessors in nighttime hours; while two indicated they will do some initial 24 coverage.

2.5.2 Forecasting Major Events

Several respondents noted that it is important to retain historical data on storm event details, damage extent, resources needed and restoration effort needed. At least one uses a forecasting model that considers historical data and current weather data to estimate the extent of possible damage and the areas most likely impacted. Employee experience and historical knowledge, combined with current data, is very important in forecasting events.

One utility is cautious about being too proactive in mobilizing resources based on forecasted data. They noted that the storm may change course or diminish in intensity, causing unnecessary cost to mobilize when not needed. This is a balancing act that improves with experience and good data.

2.5.3 Initial Damage Assessment

The companies surveyed all attempt to get an understanding of the level of damage as quickly as possible. Estimating the extent of damage is done differently by many of the respondents. Estimates were based on:

- Number of customers out (from an OMS and/or customer calls)
- Amount of load reduction (from SCADA/EMS)
- Type and severity of storm
- Sampling of damage in predefined areas
- High level damage assessments from flyovers and other sources

Most utilities surveyed perform their initial damage assessment by generally flying or driving the distribution lines along roadways, supplementing with foot patrols for difficult to reach areas. Use of field supervisors to perform an initial assessment is the practice of several major utilities, especially as they are called to work from home and can survey the damage as they drive.

This information from the field is combined with circuit and customer out information from an outage management system (if they have one) or, in one case, GIS to determine the initial extent of damage. Several companies use this initial high level information to determine the number of resources to be requested from foreign utilities. A couple of utilities use an analytical model for this assessment.

2.5.4 Detailed Damage Assessment

The detailed damage assessment is performed by the regularly assigned damage assessors. For efficiency reasons, the majority of the surveyed companies (i.e., 70%) only perform a detailed assessment (i.e., they don't perform an initial high-level assessment followed by a detailed assessment).

Many utilities pair the damage assessor with another person familiar with the territory, such as a meter reader or customer service field representative, who primarily drives the vehicle. This frees the damage assessor to focus on assessment work.

Data collected include the facilities damaged, vegetation clearance needs and access to easements. Information is recorded on some type of mobile data terminal, or mobile computer. Verbal information is communicated via radio.

2.5.5 Restoration Time Estimates

A number of utilities are using some form of modeling to determine the extent of damage and the overall restoration time. These models range from spread sheets to outage management and geographic information systems to stand-alone predictive models. The models reflect the best estimate using data such as: number of customers calls, type of damage experienced (e.g., lightening, wind, ice, snow, heat), reduction in energy load. One utility which can experience hurricanes on a fairly regular basis uses a weather model to predict the potential damage levels.

The damage assessors are not required to provide an estimate of repair time. This estimate will come from the outage management system or field crew assigned to the repair. Only one company was requiring this of their damage assessors.

2.5.6 Information Use

Most respondents stated that damage assessment data is placed in some type of system or database for review, analysis, and reporting. The damage extent, resources needed for restoration and estimated time to restore is determined from this data.

Information pertaining to the accessibility to rights of ways and easements appear to be most important to those companies that have substantial cross-country transmission and distribution lines. Highly urbanized utilities find this information of little use.

There is a clear need to understand the vegetation situation so that the right resources can be acquired. All companies want this information.

All respondents indicated that they want to know if there are wires down. Live wires down reports get highest priority. Damage assessors are to stay on scene until the appropriate crews arrive to make the situation safe. In addition, one company indicated they wanted to know if other hazards were present, such as leaking transformer oil.

All companies want to have a clear understanding of the damage and any major equipment involved and if there are any environmental hazards created.

Damage assessors are generally required to identify the major materials damaged. These materials would include pole and wire size and any equipment damaged, such as transformers.

Damage assessors are generally not required to identify the crew requirements for repair, although four of the respondents were expecting them to provide some level of information.

The damage assessment data is primarily used by individuals responsible for assigning restoration work to crews. In two instances the information is also used by the EOC/ICC units.

A unique method used by one utility for obtaining an assessment of specific facilities damaged is for the EOC to receive and review a copy of the specific material list generated by area operating offices to a central warehouse. In this manner, the number of poles, conductors, transformers, etc. is obtained for ETR estimates and restoration planning by the EOC.

2.6 Information Technology (IT)

Most of the respondents use some level of automation. Several utilities use in-house developed systems that address the specific needs for damage assessment, prediction analysis and to help manage the storm event. Outage Management Systems (OMS), Mobile Workforce Management (MWM), and Geographic Information Systems (GIS) are important technologies that several utilities use to define damage extents, to perform restoration assessments and prioritization, and to support damage assessors and restoration crews in the field.

Initially, the systems are used to define the work required and the resources necessary to perform the work and develop an estimated time to restore. Then they are used to prioritize the work for the crews. Advanced systems can integrate work management information to communicate status of work orders associated with events (e.g., communicate to customers the status of the restoration work associated with their outage).

A majority of the companies maintain or have plans to store some form of the outage data. The data is used for a number of purposes including; post event auditing, tracking customer outage statistics and identify patterns in system failures.

Using historical data to predict storm damage appears to be an emerging area with some utilities and others developing the capability. One respondent believes it will help them better determine the resource requirements and pre-storm event deployment planning and staging strategy.

The data collected by these systems is used by a number of different personnel to manage emergency event responses and for calculating the potential effects of approaching weather.

Those companies not having an OMS or a damage assessment system use traditional paper based systems. It is unclear if these records are maintained for any future use.

The consensus is that these systems perform well, even under storm conditions. In some cases, the systems can slow down under the weight of the large volume of information. It is difficult to tell from this survey why some systems' performance degrades slightly as there are too many factors which would need to be reviewed and understood. One company estimated their OMS improved their restoration time by more than five days.

2.7 Earthquake Plans

Sixty percent of the respondents indicated that earthquakes are not part of their damage assessment and restoration plans as there is little probability of one in their service territory. The remaining respondents feel their current plans are adequate for earthquakes.

Of those companies responding to the question of special needs for earthquake damage assessment, they generally felt their current processes were adequate.

The companies that responded to questions about their earthquake plans felt there was no known distinction in their approach to earthquakes versus other emergencies.

3. Summary Key Findings and Leading Practices

This section contains a summary of the key findings from the survey responses, and a determination of leading practices based on KEMA's analysis and assessment of industry leading practices.

The survey results were assessed based on a number of factors, including:

- The respondent company's environment relative to PSE
- Organizational approaches used for damage assessment
- Damage assessor's skills, qualifications and training
- Work methods and approached for conducting damage assessments
- Support and technologies deployed

The term "leading practices" as used in this report denotes an approach or practice that, in KEMA's judgment, can be considered as industry leading and noteworthy for PSE's consideration.

3.1 Organization

Leading practice: **Advance opening of the EOC/ICC with field forces on alert and staged based on forecast modeling - combining historical data with current storm event information.**

While either an Emergency Operations Center (EOC) or Incident Command Center (ICC) approach will work, there are a number of advantages to using the ICC structure. There are two schools of thought when deciding to open an EOC/ICC: first is when the damage is above some level of preset thresholds, usually defined in the emergency restoration plan; and second, when impeding weather appears to warrant opening. Different hierarchies of EOC/ICC should be established based upon the severity of the event.

3.2 Resources and Skills

Leading practice: **Draw principal damage assessors from local resources who have direct experience and knowledge associated with field construction.**

When sourcing damage assessors, the principal damage assessors should come from local districts. Local knowledge of the system should be the principal driver for this decision. Draw damage assessor candidates from line forces and in particular the field engineering or technician ranks. The regularly assigned damage assessors' primary job should include planning, design or field engineering. After these resources are depleted, the preference should be to draw next from those areas that have direct experience and knowledge associated with field construction.

Leading practice: Determine resource levels based upon the severity of the event.

This practice for determining the number of damage assessors to deploy was identified based on one company which experiences a number of significant annual events. The company feels the level of the event dictates the number of circuits each damage assessor can handle effectively in a given period of time. The company had calculated the number of damage assessors by the number of circuits they will patrol and the intensity of the event. Several other respondents use the severity of the event as a gauge for the number of damage assessors assigned.

Leading practice: Conduct some level of training prior to the commencement of the storm season.

It is also important to perform annual exercises, even if only tabletop.

Leading practice: Provide damage assessor kits.

The kits contain the material needed by the damage assessors to complete their field work - including circuit maps, safety equipment, forms and other personal gear. Photographs of construction types and cameras should also be included.

3.3 Estimated Restoration Times

Leading practice: Predict a global estimated restoration timeframe based upon historical data in a static model driven by the type of event (e.g., lightning vs. wind vs. heat, etc.) combined with other estimating factors.

Several leading utilities make this prediction within 12 hours after the event, and report high levels of accuracy. One company stated that this prediction became their "stake in the ground" for determining the number of resources (e.g., foreign crews) that would be deployed such that they could meet this commitment.

This global estimated restoration time is developed separate (but in parallel) from the detailed damage assessment, since it can be performed by different personnel. For utilities with large territories, the leading practice is to employ the model early and track progress to get a better sense of the level of damage and the potential restoration time.

Leading practice: Obtain a clear sense of the level of damage during the initial detailed damage assessment.

Specifically, companies are looking for estimates of damaged poles, spans of line down and other equipment damage. In addition, there is a critical need by some to understand the level of vegetation down which impedes the repair process.

Leading practice: Develop localized estimated restoration timeframes based on job schedules related to specific circuit repairs and associated customers.

As the outage work proceeds, new estimated restoration times are developed based on 24-hour look-ahead schedules for a batched number of jobs and associated site damage assessor estimates. Leading practice utilities associate these batched jobs with specific customers to provide more localized estimates. Best practice is to update the estimates for specific customers as their jobs are dispatched.

Leading practice utilities have specific business processes and methods in place that everyone uses for damage assessments, processing of data and reporting.

3.4 Technology Utilization

Leading practice: Utilization of a comprehensive Outage Management System (OMS).

Leading practice functionality for this system includes the ability to associate outages and incidents with customers, and aggregate customer calls to common devices in order to consolidate related calls into a single incident. A best practice is a system that is specifically designed for damage assessment and restoration planning with interfaces to outage analysis, customer service and work management systems – as well as mobile data terminals for receiving and sending data electronically to the field. Another leading practice use of an OMS is to offer the outage data to the county and service area, and to the feeder level, if possible.

<u>Leading practice</u>: Collect damage assessment data in the field by entering the information on a Mobile Data Terminal (MDT) and sending the information electronically back to the operations dispatch center.

As discussed in the previous topic, the leading practice for developing a global estimated restoration timeframe is to utilize a model driven by relevant high-level estimating factors. The model is continually improved based upon actual data from each event.

3.5 Earthquakes

The participants in this survey have not given earthquakes a lot of thought. They feel that earthquake event occurrences are not significant within their service territory and if they do occur, the resulting damage is not great. In KEMA's opinion, none of the utilities presented comprehensive and effective plans for dealing with damage caused by an earthquake. Based on our experience, earthquake damage must be assessed very differently, and the associated restoration effort entails different types of skills and equipment.

One major effect of earthquakes is that it damages underground structures as well as above ground structures. Damage to underground circuits, equipment vaults and structures are much more difficult to assess and restore than overhead circuits. Conduits and cable duct banks can shift, causing breaks in cables, especially at splices. The location of these breaks may be difficult to locate and repair. Equipment such as transformers and switches in underground vaults can get damaged from severe shaking, causing hazardous material spills and unsafe conditions. Restoration and repair will require special training and equipment under these conditions.

Utilities in earthquake prone areas must plan for this specific type of event because is differs significantly from above ground storm event damage and restoration efforts.

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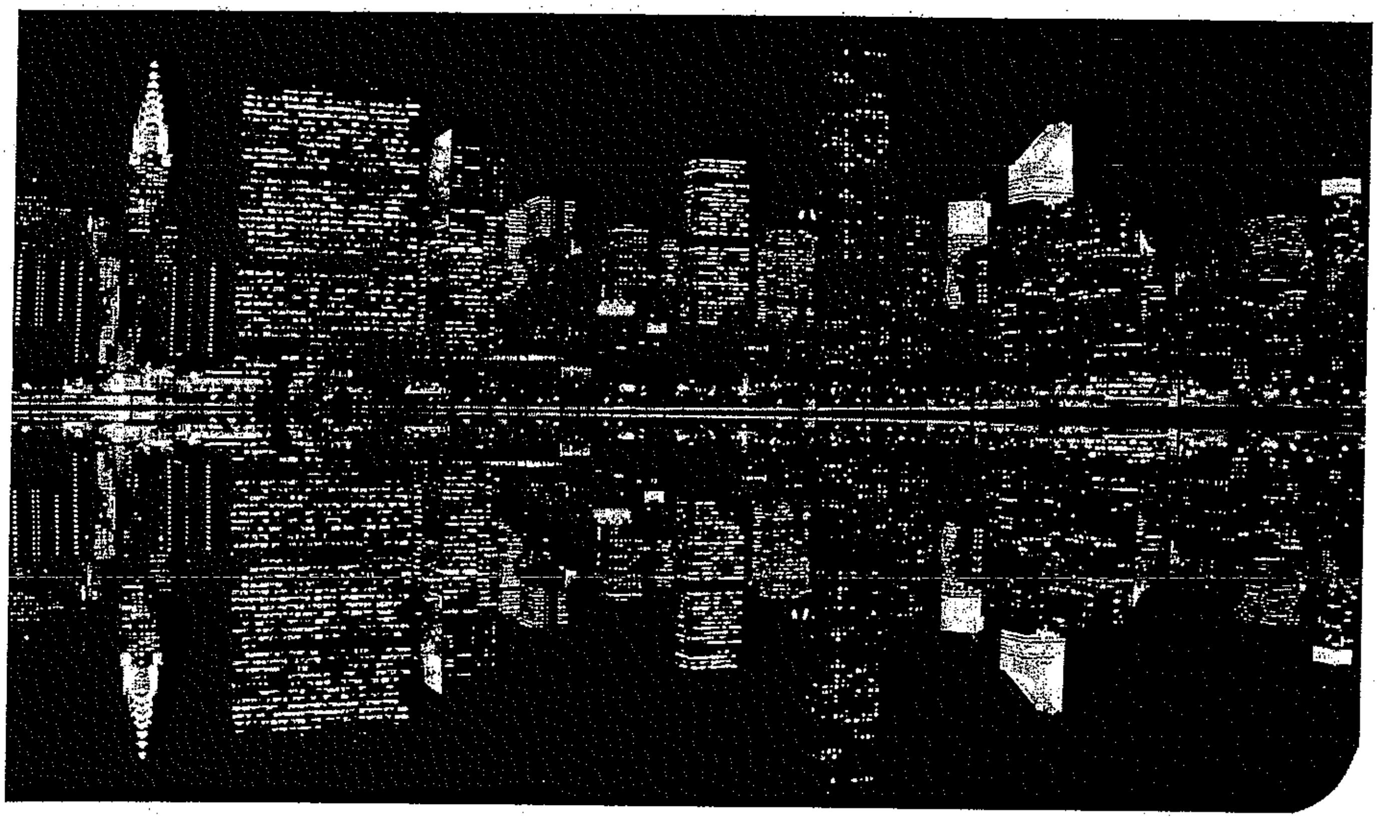
Damage Assessment Supplemental Information



Puget Sound Energy

July 31, 2008

KEMA

Table of Contents

1. Introduction

In May 2008, KEMA delivered a survey to Puget Sound Energy (PSE) on business practices related to storm damage assessment. This effort was the direct result of KEMA's conclusions and recommendations around PSE's damage assessment processes and staffing that were included in the July 2007 report titled, "Windstorm of December 14-15, 2006," and results from PSE's own post-storm analysis. PSE initiated the damage assessment leading practices survey to address the July 2007 findings, understand industry leading practices in this critical area, and determine the appropriate future actions.

Several of the responses in the survey were inconclusive, and PSE requested that KEMA conduct additional interviews with several of the companies to better understand their practices related to:

- Conducting and using information from windshield surveys
- Conducting sample and/or percentage-based surveys
- Adoption of the Incident Command System (ICS) model and its deployment in the field (i.e., operating structure and span of control)

Follow-up telephone interviews were conducted with the following six companies relative to these three topics:

[redacted]

Write-ups of these interviews are contained in the Appendix, and this report summarizes the key findings and conclusions.

PSE's primary goal was to improve damage assessment effectiveness during major storm events. Secondary goals included support for associated training programs, organizational models, staffing deployment plans and management of work activities.

1.3 Approach

KEMA's approach to conducting the survey and documenting the results and findings included the following activities:

- A questionnaire was developed in conjunction with PSE to cover key areas of interest and specific issues. The questions are included in Appendix A.

- Participation in the survey was solicited from the following 22 utilities:

[redacted]	[redacted]

- Of the 22 utilities contacted to determine their interest in participating in the survey, the following ten agreed to participate:

[redacted]

[redacted]

- Interviews were conducted and survey response information was collected. The participant list for these ten companies with contact information is included in Appendix B.

- The survey response data was compiled into an Access database for analysis by company and by question. These reports are included in Appendices C and D.

- The survey responses were analyzed with regards to:

  - Company environment relative to PSE
  - Organizational approaches used for damage assessment
  - Resources, skills, qualifications and training
  - Work methods utilized for conducting damage assessment activities
  - Technologies and tools deployed

- Based on this analysis, KEMA identified and documented key findings.

- Leading practices were identified based upon these findings and KEMA's industry knowledge and experience.

- This final report was developed to document survey results, findings, analysis and conclusions.

2. Summary of Responses

This section summarizes the interview response information that was received. Notes from the interviews are contained in the appendices.

2.1 Windshield Surveys

The companies that perform windshield surveys typically use this information to gauge the magnitude of the event and damage incurred (i.e., "did we get hit; and if so, how bad"). This information is then used for restoration planning and the deployment of resources. The information is not typically captured in any system or used to develop any sort of detailed damage assessment or estimated restoration times. The information does provide a basis for directing damage assessors, crews and other field personnel during the first hours of the event. The initial damage assessment is just that; a high-level assessment of the damage to determine where the focus should be and to plan for restoration resources. The information is sometimes kept as historical data, but is not typically used for any predictive purposes.

One of the companies uses the information to develop a "One Hour Report" immediately after the event. Another company is planning to improve the accuracy of the windshield surveys by making them more random (i.e., statistically valid) – as compared to the current ad-hoc nature of the areas being reported upon. One company immediately follows the windshield survey with a more detailed damage assessment when the damage is not significant. One company found that much of the data that was initially collected was not being used in the field for restoration work, so they are now limiting the data to only information that is of value to the ICS.

2.2 Sample and/or Percentage-Based Surveys

All six of the companies use some form of a model to develop initial damage predictions or assessments. A couple of the companies use the same model that was developed by an outside consultant. All of the models are based on custom developed software, but some are built on commercial GIS / OMS platforms - several were spreadsheet-based.

The models use high level metrics (e.g., circuits locked out, wind speeds, customer calls reporting lights out, load shed, weather data, historical data, etc.). The models do not use input from damage assessors in the field since they are typically run during the first 6-12 hours after the event (i.e. before initial damage assessment reports are processed). The models develop predictions based on historical data and broad (subjective) measures. Different models are needed for different event types (e.g., tropical versus ice storm).

Several of the companies are in the process of refining their models to reflect more detailed weather and facility information. The objective is to provide more accurate predictions at a more granular scale. One company has a goal of 95-100% accurate forecasting on a scale of 2 km areas. Two of the companies are using Weatherbug to develop and capture detailed weather information. Weatherbug is a commercial on-line weather service that provides live neighborhood weather, forecasts, storm alerts, and local radar pictures on a desktop. This information is being combined with asset information to predict damage. One company's goal is for the model to become a "virtual damage assessor."

Another company is working on a sophisticated model that will estimate wind intensity and duration by GPS location - mapped to substation locations and circuit information. Curves are being developed to plot wind direction and duration against anticipated structure loss (i.e., spans down) and estimated labor and time required to restore numbers of spans. When complete, this new model will predict damage and restoration efforts based on actual storm conditions.

2.3 ICS Model Adoption and Deployment

All six of the utilities surveyed follow the ICS model to some degree. Two of the companies follow the NIMS format where ICS is embedded within NIMS. Several of the companies noted that the model was developed for fire departments, and doesn't fully fit the electric utility industry. One multi-state utility noted that the ICS model aligned very well with the lower level management structures they were already using, but did not fit the upper levels, which must support a complex set of different State jurisdictions. Their modified operating structure has service centers that report to regions (geographically aligned) which report to States (jurisdictionally aligned). Another utility uses three levels of hierarchy: 1) street level; 2) regional/area level (i.e., control areas, service territories); 3) corporate-wide level. Their difficulty is in transitioning from one level to the next for major events.

Several of the companies follow the model for their organization, roles and responsibilities, reporting, functions and communications. They also extend the model into the field for reporting relationships, span of control and communications. The recommended span of control for the ICS model is 5:1, which relates to the number of different types of activities being controlled. One company felt the span of control can be increased (i.e., 10:1) if the same function is being

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managed (e.g., all overhead crews). For company crews, they have one person responsible for five supervisors who are responsible for five crews – resulting in a 25:1 overall ratio. They believe they need less supervision for contractors, since contractors are typically accustomed to working more independently.

Several companies stated their Incident Command Center is structured around the five ICS major components:

- Command
- Planning
- Operations
- Logistics
- Finance/Administration

For organization in the field, they have what are called "On-Scene Commanders." They are located in one or each of the operating base yards. The damage assessors report their findings to On-Scene Commanders or Circuit Captains, who then consolidate the information and send it to the ICC Incident Commander. Damage assessors in the field are thus part of the "Operations" component of the ICC.

Most utilities leverage FEMA training courses that support specific functions (e.g., EMI). Some primarily use the management level courses, while other utilities (e.g., in order to be reimbursed by FEMA) follow the courses down to the crew levels. Since these training courses are based on the ICS organizational models, they influence companies to follow the same structure. One company participates in the South East Electric Exchange, and noted most of these utilities are also starting to follow the same operating structures – both to leverage the FEMA training material and to better align with governmental entities.

KEMA

3. Summary Key Findings and Leading Practices

This section contains a summary of the key findings from the responses, and a determination of leading practices based on KEMA's analysis and assessment. The term "leading practices" as used in this report denotes an approach or practice that, in KEMA's judgment, can be considered as industry leading and noteworthy for PSE's consideration – recognizing that the limited number of participants in this survey do not adequately represent the industry as a whole.

3.1 Windshield Assessments

Leading practice: **Use windshield assessments to gauge the magnitude of damage for restoration planning purposes; make sure the sample is valid.**

A rapid initial damage assessment performed immediately after a major storm event is necessary to determine, at a preliminary level, the magnitude of the damage to the infrastructure. The estimate should be as accurate as possible, using input from a statistically valid sample of the service territory.

This can be accomplished in a number of ways, including the use of individual company employees as they drive to report to work, aerial fly-over of the impacted areas, and the use of damage assessors to perform the initial "windshield" assessment. The information should be used both by the ICC to begin the restoration planning process and the regional operating areas to mobilize resources. A standard set of data to collect for this initial assessment should be pre-defined.

3.2 Sample or Percentage-based Surveys

Leading practice: **Use a prediction model based upon high level inputs not dependent upon damage assessment reports from the field; use different models for different storm types.**

The models should use high level metrics available from internal sources and processes (e.g. circuits locked out, wind speeds, customer calls reporting lights out, load shed, weather data, historical data, etc.) so that estimates can be made without waiting for damage assessment reports from the field. The model predictions should be refined based on historical data and actual results. Future refinements can include the development of more granular estimates and predictions based upon detailed weather and asset information.

3.3 ICS Model Deployment

Leading practice: Align organizational and functional structures with the ICS model to facilitate coordination with other entities, but modify as needed to meet specific requirements.

The ICS/NIMS model for emergency response generally aligns with a utility's organization and provides the proper framework for establishing the emergency response functions. The model may have to be modified to fit specific operational needs, but the five ICS major components still apply:

- Command
- Planning
- Operations
- Logistics
- Finance/Administration

The model should be extended to the field for functions, reporting relationships and span of control. Damage assessors should report to local commanders, who report to the ICC Incident Commander. Leverage available on-line FEMA training courses that support specific functions. These courses are based on the Federal ICS model which allows consistency when the utility follows the same structure.

4. Recommended Action Items

Several utilities who participated in this damage assessment survey have extended invitations to visit their location and view the tools and processes used for damage assessment. It is highly recommended that PSE take advantage of these invites to see how other utilities perform damage assessments. These utilities include the following.

[redacted] Of interest is to look at their application called "Assessment Pocket System" which uses a field assessment software on a mobile terminal device and that is interfaced to their outage management system.

[redacted] View the use of their outage management system for damage assessment and restoration planning.

EXHIBIT G

Web-Map Display Demo

Service Alert Map

City View | ZIP Code View | How to Use this Map

City Outage View shows estimated numbers of customers affected

This map displays the latest estimated number of customers without electric service in a selected community. Enter a city's name in the left-hand column's "Search" box or hold your cursor over a particular location on the map to get the most up-to-date number of PSE customers without electric service in that city. Time estimates for power-restoration in hard-hit communities will be posted, when available, on the Service Alert Latest Updates page.

Text Version

Return to Service Alert main page »

Show map details

- [x] Cities
- [x] Highways
- [ ] PSE Service Area

Zoom in to county

Select county

Refresh the map

Map data is automatically updated every 15 minutes on our servers. Refresh this page in your browser to display the latest information.

REFRESH

Search by city

Enter city >

Search results:

City: Mount Vernon

Customers: 1633

(Alternate messaging: No outages are currently indicated for the city entered.)

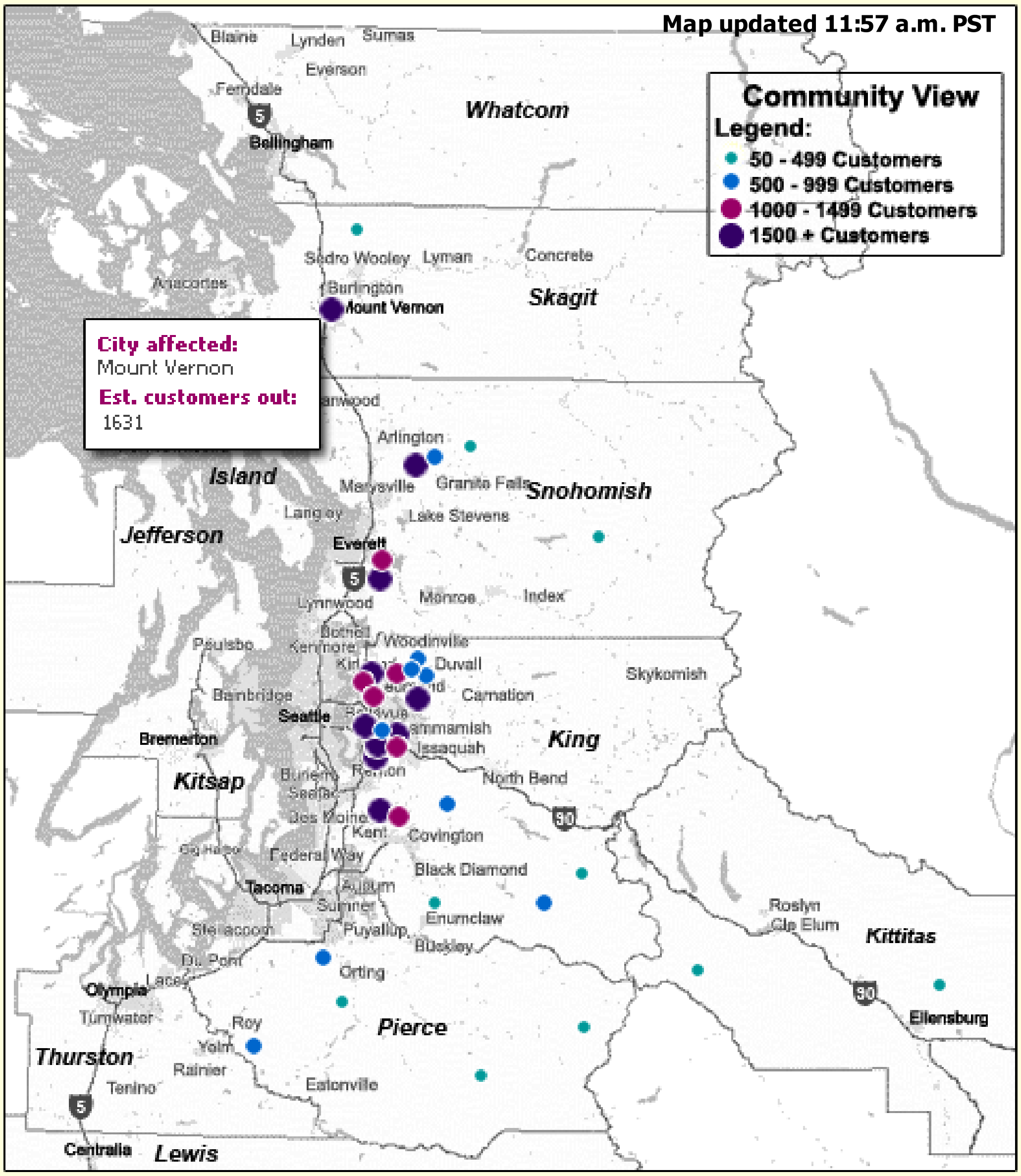

EXHIBIT H

PSE Communication Lead Assignments

PSE Communication Lead Assignments:

Kittitas
1 [redacted]
2 [redacted]

Pierce
1 [redacted]

S King
1 [redacted]
2 [redacted]

N King
1 [redacted]
2 [redacted]

Skagit
1 [redacted]
2 [redacted]
3 [redacted]

Whatcom
1 [redacted]
2 [redacted]

Kitsap
1 [redacted]
2 [redacted]
3 [redacted]

EXHIBIT I

Bothell Emergency Center (BEC)

Duties and Responsibilities

Work Location	Temporary Job Title	Duties and Responsibilities	Training Expectations
BEC (Bothell Emergency Center)	Director	Drive-bys, Advice, Financial decisions. The information focal point for the executive management team and may respond to media inquires about emergency response activities as needed by Corporate Communication. Provide support where needed.	Storm Preparedness Orientation and Overview
BEC	Manager	• Coordinates opening of the BEC and determines level of response required for each emergency. Meets with the BEC Lead staff to coordinate and communicate. • Ensures periodic detailed reports are issued. • Oversees balancing of available resources against service level and the customer experience. • Coordinate conference calls • Notify Bothell participants • Conduct regular BEC Lead Team meeting prior to the EOC conference calls or a minimum of every 2-hours at the bottom of the hour. o Each Team Lead reports current progress of their Team, work in progress and resource needs. • Prior to EOC conference call pull data to report' o SL o Number of calls taken o Number of call takers o Number or nature of escalated calls if applicable • Maintain a log of events to hand off and debrief to the next BEC Manager. • Maintain copies of all communication: • Agents • BEC • EOC • VRU messages (hard copy folder) • Coordinate with staffing to ensure BEC wall charts are updated with time stamped number of calls taken, SL, outage number, outage events, number of call takers, escalated calls, VRU update time stamp, next sched	Storm Preparedness Orientation and Overview
BEC	Staffing	Assist in the allocation and retention of People resources as required by BEC including non-Customer service staff to maintain service level and customer experience and coordinate the following roles. • Team Lead attends all BEC team lead meetings. • Manage Revenue scheduler (1 to coordinate) • Call-out / scheduler (non-Customer Service) (team of 4 , 2 per shift) • CAC scheduler- Designated staff forecaster 2 (1 per shift) • Include Provisions team lead in all Staffing storm meetings. • Training Coordinator • Admin support • Coordinate with BEC Manager to ensure BEC wall charts are updated with time stamped number of calls taken, SL, outage number, outage events, number of call takers, escalated calls, VRU update time stamp, next scheduled EOC conference call, and the next BEC Team Lead meeting. • Make sure that there is consistency in tracking of agents. • Work closely with IT to make sure Corporate billing queues are receiving outage calls. • When Advance warning of storm is available, meet the day before to coordinate schedules and efforts. Coordinate check-in process staffing team will notify agents of any rescheduled upcoming daily regular	Storm Preparedness Orientation and Overview

BEC	Administrative	Responsible to provide resolution, oversight to reported hardware, application, network, or key interface issues. Coordinates with PSE helpdesk, network, application personnel to ensure failures are quickly resolved or appropriately escalated.	Storm Preparedness Orientation and Overview
Work Location	**Temporary Job Title**	**Duties and Responsibilities**	**Training Expectations**
BEC	Training	Training Coordinator; • Provide necessary training to all staff. (Non-CAC call takers, Officer, Escalated Call takers, etc.) • Communications team provides storm update/overview to class at the end of their training and just prior to reporting to take calls. • Create training team schedule (use Outage Training - Non-CAC Call Takers template). • Attend BEC Team Lead and Staffing Team meetings and conference calls. • Check supplies, prepare packets. Headsets are handled in the Check-in process • Check training facilities (computers available, pens/pencils). • Review upcoming daily training for notification to any non-training staff (outside) trainers and notify staffing team to determine if/when training will take place or be rescheduled. Staffing team will notify agents of any rescheduling including Revenue Mgmt. Create training teams schedules and report to BEC manager	Storm Preparedness Orientation and Overview
BEC	Communications/ Messaging	Ensures timely and accurate communications with Corporate communications, agents BEC team. Coordinates VRU, web, and agent messaging. Acts as EOC liaison, a. Media/Corporate Communication/Webb. VRU messaging c. EOC liaison/escalation coordinator d. Agent messaging e. CLX restoration f. Coordinate updating QRM with BEC Updates g. Create and Name Storm File Under the I Drive h. Time Stamp QRM Updates at top of every hour. i.	Storm Preparedness Orientation and Overview
BEC	Provisions/ Resource Coordinator	• Coordinates all non-staffing resources to include list below to keep staff functions 24x7 as needed, for o Hotels o Food/Meals o Supplies o Janitorial o Transportation o Generator fuel • Attend staffing meetings • Coordinate provision team needs • Create team Schedules and report to BEC manager • Report meal plans messaging team for BEC updates	Storm Preparedness Orientation and Overview
BEC	IT support	Responsible to provide resolution, oversight to reported hardware, application, network, or key interface issues. Coordinates with PSE helpdesk, network, application personnel to ensure failures are quickly resolved or appropriately escalated, ensuring mission critical technology tools are returned to service as soon as may be practical. Will monitor and notify technology partners of increased volume and will monitor for signs of potential system failures and prevent them if possible. a. Phone extensions(Patti, Al, Lauri) b. PC support(Nancy Agler) c. Phone/VRU	Storm Preparedness Orientation and Overview

Bellevue	Energy Efficiency	Coordinates and communicates with the BEC Staffing Team regarding phone support for Bellevue Non-CAC call takers.	Storm Preparedness Orientation and Overview

EXHIBIT J

Cost Benefit Analysis of OMS/GIS Initiative

Cost Benefit Analysis of
OMS/GIS Initiative

February 13, 2008

Puget Sound Energy

Storm Restoration and Readiness

Outage Management System/Geographic Information System

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1. Executive Summary

This document presents the cost benefit analysis for the procurement, implementation, production use, and maintenance of an Outage Management System (OMS) with a supporting Geospatial Information System (GIS) for Puget Sound Energy (PSE).

The cost benefit analysis performed by KEMA, Inc. (KEMA) concludes that implementation of a commercial OMS will meet PSE's outage management requirements, that a commercial GIS is needed to support the OMS, and that a phased implementation and deployment of OMS and GIS will provide the needed benefits and operational efficiency for outage management and service restoration. This approach also establishes the foundation for achieving longer term benefits around improved spatial information management, enterprise wide access to timely and accurate geo-referenced data, and better coordination among different business units for end to end process improvement in planning, design, deployment, operation, and maintenance of distribution assets.

KEMA's assessment of OMS/GIS cost benefit analysis is based on a 15-year aggregated cost and benefit calculation with due consideration for providing the necessary tools for operating a modern electric distribution network in a safe and reliable manner.

1.1 Business Requirements

Responding to and managing unplanned electrical outages ranks as one of the most important operations functions for electric utilities. O&M costs, customer satisfaction, and critical reporting to regulatory agencies are all affected by PSE's ability to respond quickly and safely to both day-to-day and storm related unplanned outages.

There are numerous business requirements identified for the implementation of a commercial OMS with a supporting GIS and process improvements. They include the following:

- The recent major storm event of December 2006 showed that there is a need to improve the outage management function at PSE with information management and automation tools and business process improvements;
- Functionality is needed that will improve the communication of outage status, the estimated restoration time, and any re-energized status to enable this information to be communicated in a timely and efficient manner to those within PSE and to those external to the organization;
- The prevalence of manual processes and paper-based maps is a hindrance to achieving higher efficiency in service delivery, outage management, and service restoration work;

- There is a need for a comprehensive software system that will bring together all key information associated with outage and improve management of outage events, perform predictive analysis of outage locations, and provide estimated restoration times;
- All aspects of electric distribution can benefit from access to more accurate, timely, and complete information about energy delivery facilities and their locations; and,
- Proper integration of systems is needed to achieve desired performance for outage management and restoration for both normal and storm condition unplanned outages, and for the management of planned outages and clearances.

1.2 Recommendations

Based on the results of the earlier KEMA Storm Assessment Analysis[1] and the cost benefit evaluation work performed here, we recommend that PSE undertake the following activities:

A. Develop detailed requirements and procurement specifications for a commercial off the shelf Outage Management System (OMS) and a commercial off the shelf Geographic Information System (GIS) that support the OMS. Perform a vendor assessment of commercial OMS and GIS products, make a selection and confirm the selection.

B. Implement a multi-phase, multi-track deployment of the technology and the associated process improvements for outage management as described in this report.

C. Perform process reengineering to integrate enabling technologies into business processes to optimize both tool and process.

D. Provide adequate training and change management on new technologies to maximize their utilization and achieve desired operational gains.

E. Implement a technology investment and roll out plan that is flexible and subject to annual reviews to insure that any necessary adjustments can be made in response to changing business and regulatory requirements.

1.3 Multi-Phase Solution Approach

KEMA recommends a three phased approach for the implementation of the outage management solution and the supporting capabilities at PSE. The three phases are:

[1] KEMA Windstorm of December 2006 Storm Restoration and Readiness Review

- **Outage Data Mart**. Develop and implement an Outage Data Mart (ODM) in time to support the year 2008 storm season. The ODM brings together the many outage and restoration data sets and formalizes the query, management and access process to this data. The intent is to leverage existing PSE data sources and systems, and to augment them with new capabilities to provide an aggregate source of information for operations support, improve estimation of restoration times, and support communication and reporting of outage status information for internal and external purposes. The ODM will include capabilities for consistent collection and management of damage assessment reports and will provide data mining capabilities for forecasting and estimations.

- **Base OMS Function**. The second recommended phase is to implement a base Outage Management System (OMS) for unplanned outages in time for the year 2009 storm season. The OMS will be a commercial software that will meet PSE business needs for outage management while being highly configurable with a minimum amount of customization. It will provide the functionality needed to manage unplanned outages for normal and storm conditions. In order to support the OMS, a commercial Geographic Information System (GIS) is needed to provide the electric distribution network connectivity information for outage analysis, and for restoration management processes. Implementation of the GIS in this phase will be limited to that which is needed to support the OMS. Data and functionality will also be provided, however, to support transmission vegetation management.

- **Advance OMS Functionality**. The third phase will provide additional outage management functionality, including planned switching, clearance management and power flow analysis. Integration to the Mobile Workforce Management (MWF) system will provide the ability to dispatch trouble orders to the field efficiently and to receive status reports and estimated time for restoration. This phase is planned for the year 2010 storm season.

  During this phase and beyond 2010, additional GIS functionality can also be developed and implemented to leverage the GIS tool to provide support to engineering, system planning, system maintenance, system operations, field functions, and asset management for both gas and electric. It is recommended that PSE leverage the base GIS package implemented in support of the electrical outage management with an incremental set of functions to provide a complete GIS capability for electric and gas applications. This capability will replace the existing PSE raster CAD drawing-based maps with a best practice GIS application.

The timing for deployment of the three phases are planned to coincide with annual storm seasons in order to provide a continuing series of additional functionality to meet each year’s storm events. The timing for the three phases is summarized below.

- **Phase One** – Outage Data Mart: Storm Season 2008
- **Phase Two** – Base OMS Function and GIS Network connectivity Model : Storm Season 2009
- **Phase Three** – Advance OMS Functionality: Storm Season 2010

Note that as stated above, additional GIS functionality can begin in Phase Three and extend beyond the 2010 storm season target to incrementally add more applications that take advantage of the GIS technology. These added functionality and applications are included in the cost benefit analysis for implementation consideration.

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1.4 Cost Benefit Analysis

This analysis brings together the discounted net present value of the costs and benefits associated with the proposed recommendations over a 15 year time horizon inclusive of the three years implementation time span.

The total OMS project cost is estimated a[redacted] This cost is inclusive of technology specification and procurement, vendor software license, hardware, implementation, integration, rollout, and change management costs. A breakdown of this cost is illustrated in Figure 1-1.

OMS Costs ($000)	
Specification & Procurement	$ [redacted]
Software License	$ [redacted]
Hardware and Mapboard	$ [redacted]
Outage Data Mart	$ [redacted]
Phase I OMS	$ [redacted]
Phase II OMS	$ [redacted]
Total	$ [redacted]

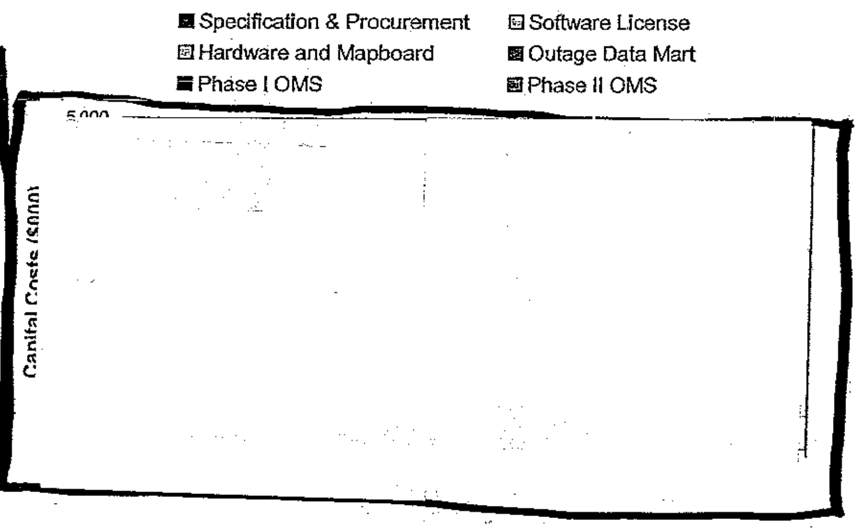

Figure 1-1 OMS Capital Cost Estimate ($000)

The following chart shows the current and expected reduction in PSE System Average Interruption Duration Index (SAIDI) with a fully implemented OMS. It is estimated that a 17% reduction in SAIDI can be realized with the OMS.

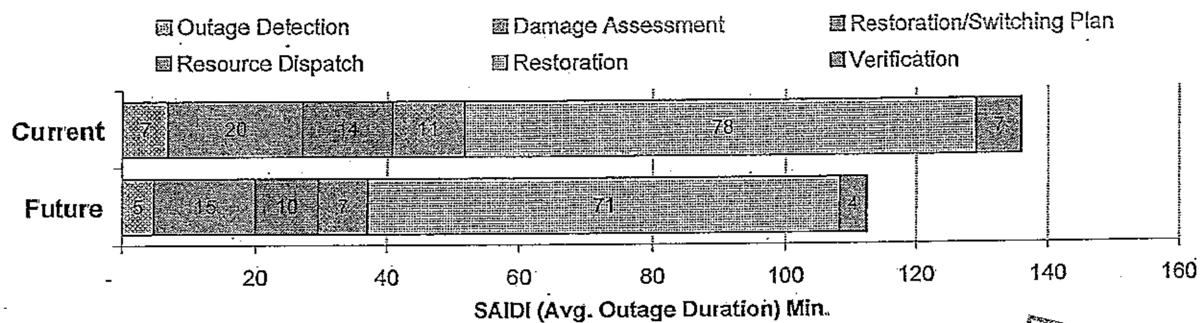

Figure 1-2 Expected Improvement in SAIDI

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The reduction in outage duration due to automation, better management of information, and improvements in crew productivity is estimated to result in Net Present Value (NPV) operational benefits of $16 8M. When compared with NPV of th[redacted]otal costs inclusive of annual O&M costs, makes the OMS a net positive project.

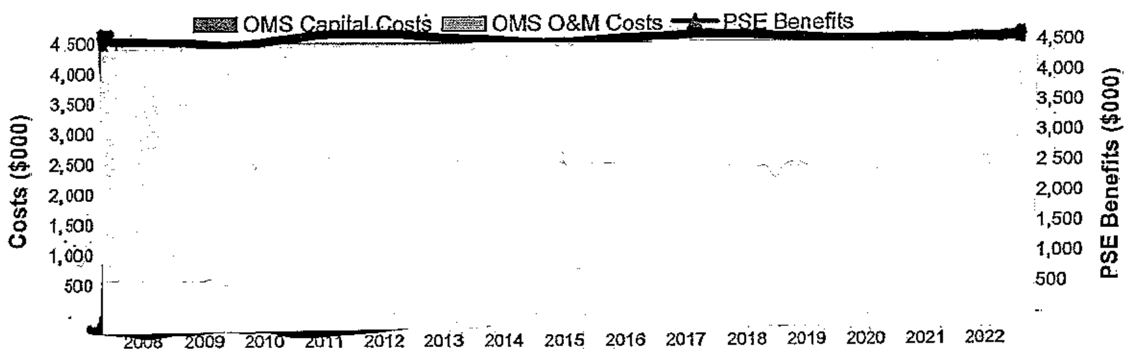

Figure 1-3 OMS Cost and Benefit Trends

In addition to the operational benefits, the reduction in outage duration and improvements in communications and customer services will bring about a significant level of societal benefits for years to come. Based on the available industry data for potential cost of power outage for residential, commercial and industrial customers, it is estimated that reduction in outage duration will result in approximately

$350M of benefits over the 15 years considering the mix of PSE's 1.07M customers and its 1.5% load growth per year.

The GIS cost, planned over a four-year implementation period, is shown in Figure 1-4. The total cost of the GIS implementation is estimated at [redacted] with approximately 25% used for the procurement of the base software, hardware, and land base capabilities, another 25% for implementation of the electric connectivity models needed for the OMS applications, and another 15% needed for completing the Electric asset and facility modeling for support of other GIS users. The implementation of the Gas application will consume approximately 35% of the budget.

In addition to addressing the needs of OMS, GIS implementation brings operational benefits across the PSE enterprise. These include both productivity improvements as well as capital expenditure savings through more accurate planning, design, and execution of capital projects, e.g., capacity expansion and systems reliability improvements by having timely access to more accurate facility, equipment, and load data. The estimated value of these benefits is summarized in Table 1-1 below.

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GIS Costs ($000)	
Specification & Procurement	$ [redacted]
GIS Software License	$ [redacted]
Hardware	$ [redacted]
Landbase	$ [redacted]
Phase I Electric Network Connectivity	$ [redacted]
Phase II Electric Facilities Modeling	$ [redacted]
Phase II Gas Trandmission & Distribution	$ [redacted]
Total	$ [redacted]

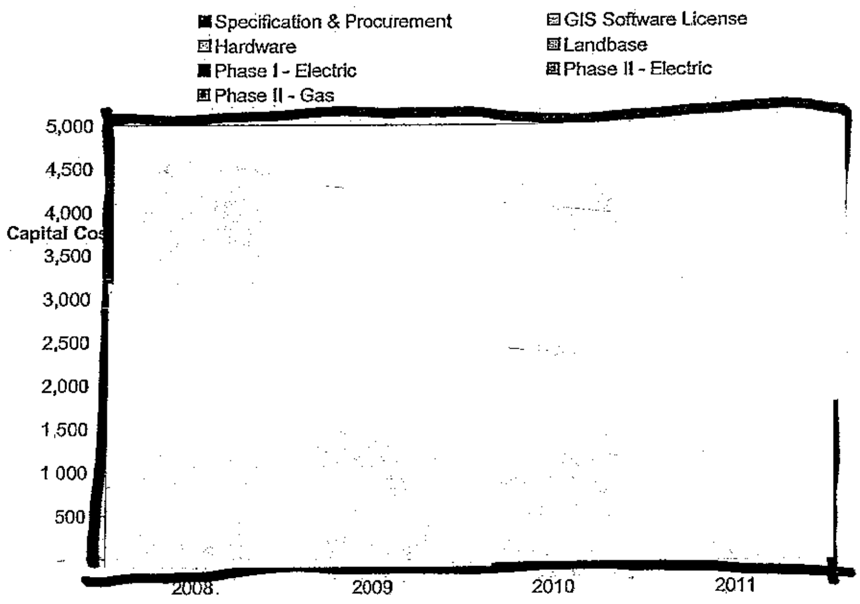

Figure 1-4 GIS Capital Costs

Based on this analysis, the GIS implementation will deliver significant positive results over its operational time horizon beyond the direct benefits provided for the outage management process. These expected cost and benefit trends are illustrated in Figure 1-5.

Table 1-1 GIS Benefits (NPV)

NPV of GIS Benefits Over 15 Years ($000)		Total
Maps & Records Department		**$10,110**
O&M Savings	$4,526	
Capital Project Savings	$5,584	
System Planning/Engineering Design		**$5,079**
O&M Savings	$1,813	
Capital Project Savings	$3,267	
System Maintenance		**$3,554**
O&M Savings	$2,788	
Capital Project Savings	$766	
Load Forecasting		**$2,018**
O&M Savings	$1,695	
Capital Project Savings	$323	
Tax and Franchise/ Regulatory Reporting		**$238**
O&M Savings	$238	
Capital Project Savings		
Vegetation Managemet		**$5,380**
O&M Savings	$5,150	
Capital Project Savings	$230	
Gas Applications and Compliance		**$9,349**
O&M Savings	$6,284	
Capital Project Savings	$3,065	
Total Benefits		**$35,728**

The cost benefit analysis here has reviewed potential project risk areas and has considered measures for mitigating some of these risks including:

- Project Schedule and Program Management Considerations;
- Migration of Existing Functionality and Capabilities;
- Business Process Impact;
- Change Management and Training;
- Resource/Skills Needs and Availability;
- Systems Integration Requirements, Issues and Considerations; and.
- Data Modeling and Data Conversion.

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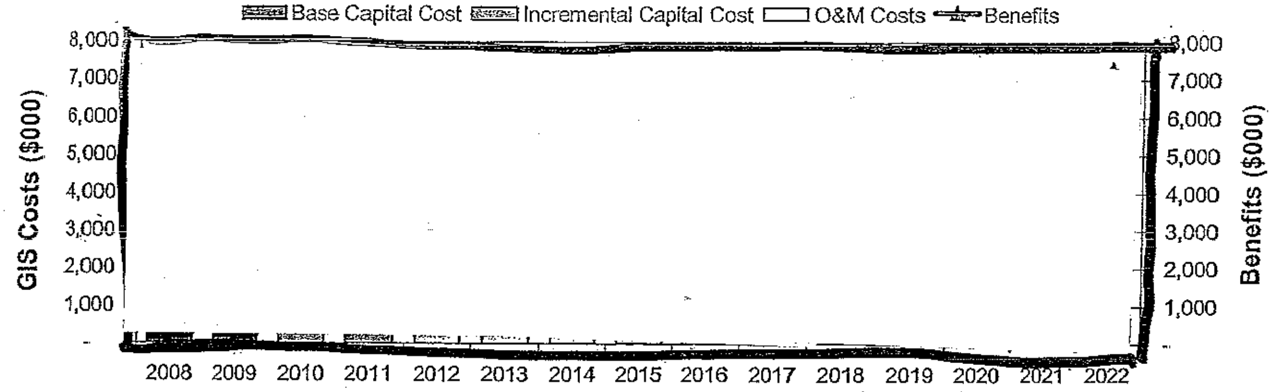

Figure 1-5 GIS Cost and Benefit Trends

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1.5 Conclusions

The following results of the OMS/GIS cost benefit analysis show a program NPV of $26M over a 15 year calculation. The waterfall diagram on the right shows the respective costs and benefits for OMS and GIS independently, with the resulting benefit NPV.

Net Present Value Over 15 Years ($000)	
OMS Benefits	$ 16,837
GIS Benefits	$ 35,716
OMS Costs	[redacted]
GIS Costs	$ [redacted]
Net Benefits	$ [redacted]

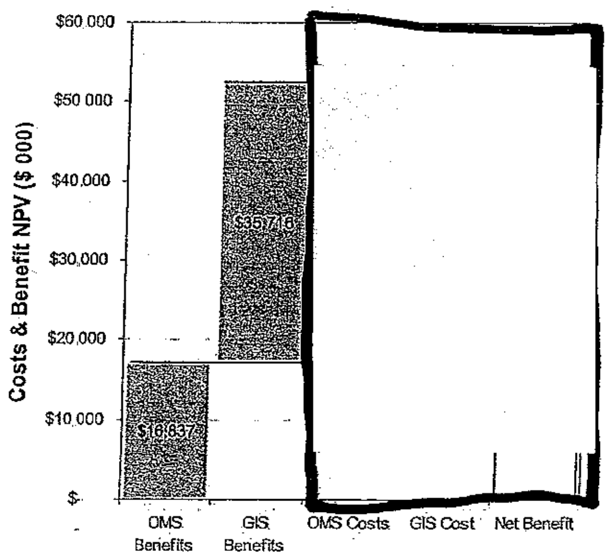

Figure 1-6 Net Business Case of the Proposed Program

2. Background

In November and December of 2006, the PSE service territory experienced unprecedented severe weather that inflicted the most extensive damage the electric transmission and distribution infrastructure had ever sustained. Severe December winds, preceded by record setting November rains, caused widespread damage to trees resulting in power outages throughout the territory. Over 700,000 PSE electric customers, representing nearly 70% of total electric customers, lost power during the "Hanukkah Eve Windstorm of 2006." As a result, KEMA was hired by PSE to perform a post-storm assessment and to make actionable recommendations in preparation for future severe storm events. The KEMA report, titled, "Windstorm of December 14-15, 2006 Storm Response Readiness Review," dated May 31, 2007, documents the findings and recommendations of this assessment.

Based on findings of this project, and coupled with knowledge of leading industry practices in the area of outage management, KEMA has identified opportunities for PSE to improve overall storm restoration processes so that the occurrence of another storm of the magnitude of December 14-15 can be handled even more effectively. These areas are summarized as:

i. Information systems that support outage information collection, analysis, and management;

ii. Damage assessment procedures and processes to identify crew requirements and estimated outage duration;

iii. Vegetation management processes and access to rights-of-way for restoration; and,

iv. Effective and timely communication to customers and the public of estimated restoration times.

This cost benefit analysis directly addresses item "i" and "iv" above by recommending an implementation roadmap and the supporting financial business case for applications and technologies needed for outage information collection, analysis and management. The applications implemented will also support items "ii" and "iii" above by providing the required information technology infrastructure in support of business processes, crew activities and the overall coordination of damage assessment, outage management and restoration activities including vegetation management of rights-of-ways.

More specifically, this report provides an assessment of a required OMS, the supporting GIS, and the integration of these two technologies with other PSE systems. The technologies of OMS and GIS are core to the proper management of outages, both unplanned and planned, and in normal and storm conditions. The business case describes the costs and benefits for both OMS and GIS, and together as an integrated and implemented package.

2.1 The Need for an OMS

Figure 2-1 shows a summary level representation of outage management process incorporating leading practices from the utility industry. This model provides a basic flow of activities and the sequence of events in the field to assess damage and carry out the restoration process. This high level process is supported by many support activities that facilitate the primary processes of event assessment, restoration strategy, crew dispatch, system repair, restoration and verification. These processes are supported by data collection, information management and analysis, and communications activities.

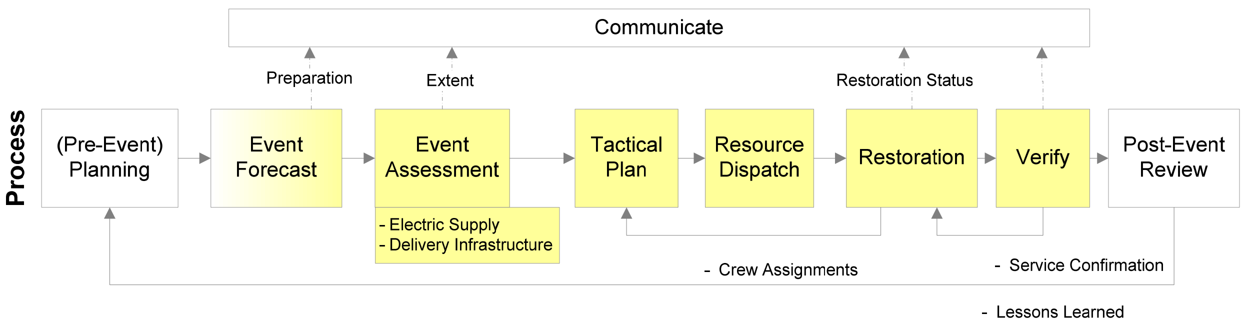

Figure 2-1 Outage Management Process

A number of function-rich OMS are currently being offered by commercial vendors for utility applications. Most of these systems have been in commercial operation for several years at many utilities. OMS is considered a mission critical utility application and as such is an integral part of many distribution utility operation centers.

The OMS provides the functionality needed to take customer calls reporting "lights out" and performs an analysis of where the most probable cause of the outage is within the electric network. The OMS will have a depiction of the "as-operated" state of the electric network in its database. Customers are mapped to each circuit, generally through a customer premise to transformer tie.

Outage events can be triggered by customer calls reporting an outage through the Interactive Voice Response Unit (IVRU), by a Customer Service Representative (CSR) entering the outage into a Customer Information System (CIS), by a device status change from EMS/SCADA, or directly into the OMS by an outage management dispatcher in system operations. Once this outage event is initiated, the OMS will begin to perform an analysis and identify the most probable protective device (transformer fuse, line fuse, recloser, circuit breaker) that opened resulting in lights-out. As more outage calls arrive, the analysis may roll-up to upstream protective devices of a circuit. Once a probable device has been indicated, the

Dispatcher or System Operator can send a first responder to the probable device location. The first responder can then send status information back to the dispatcher on the cause and damage assessment.

The status information from the field is entered into the OMS and, in turn, sent to the CIS to inform the call center of the status of the outage (customers affected) and the estimated restoration time. This information can also be sent to key stakeholders, persons who deal with the media, to those who have to coordinate major events with public agencies and to account executives that deal with major and critical customers. In this manner, outage events and status flows in a timely manner to those within the organization who need this information.

The outage management system is a proven technology for the effective management of outages. Therefore, it is the foundational technology that is being addressed in this report.

Appendix A provides a more detailed discussion of industry outage management systems.

2.2 The Need for GIS to Enable OMS

The OMS requires an accurate configuration of the electric network in order to provide outage analysis and reporting functionality. This electric network is generally created and maintained in a GIS. The GIS has the proper tools and functionality to create and maintain this spatial data. The electric network model must be fairly complete and accurate, including all electric connectivity, phases, electrical devices (switches, fuses, reclosers, transformers) and locations defined. The GIS manages this information well. In addition, customer to transformer ties must be defined. Customer to transformer relationships are generally maintained in a CIS and downloaded into the OMS on a regular basis.

The OMS extracts the required electric network from the GIS and changes the state of operating devices and equipment to an "as-operated" state (as opposed to the GIS which defines facilities in an as-constructed state. The OMS will then perform a model build to make the customer to circuit connectivity. The model in the OMS is then ready to receive customer calls of "lights out" and perform its analysis.

Land-base information contained in the GIS is also sent to the OMS for use as reference of facility locating, field crew dispatching, routing and knowing where all crews are in the field, and for coordinating the overall field workforce. Street names, operating boundaries, and natural features such as streams and lakes are helpful when performing outage and damage assessments in the field.

The GIS technology is therefore also included in the cost benefit assessment due to its need to support the OMS.

A more detailed discussion of GIS is included in Appendix B.

2.3 Organization of this Document

The document is organized in sections as follows:

Section 1 – Executive Summary. Summarizes the key issues, conclusions and recommendations of the cost benefit report.

Section 2 – Background. Discusses the need for an OMS based on the December 2006 storm event.

Section 3 – Cost Benefit Analysis Methodology. Presents the approach and methodology used to develop the OMS/GIS business case.

Section 4 – Current State Assessment. The assessment of the current state of processes and technologies related to outage management.

Section 5 – Future State Recommendations. Describes the recommended technology solutions for the OMS and GIS including data integration requirements to meet outage management business needs.

Section 6 – Implementation Roadmap. The plan and schedule for the implementation of the recommended OMS and GIS technologies and related system integration tasks.

Section 7 – Cost Assessment. Presents the capital and O&M costs for the OMS and GIS and the cost models. Also includes a discussion of qualitative benefits.

Section 8 – Benefits Assessment. Provides a discussion of qualitative benefits for OMS and GIS and presents the quantitative benefit results for both technologies.

Section 9 – Business Case Analysis. The financial results of the business case cost benefit analysis. Also includes program risks and risk mitigation.

Appendix A – Outage Management Systems. A generic discussion of industry outage management systems.

Appendix B – Geographic Information Systems. A generic discussion of industry geographic information systems.

3. Cost Benefit Analysis Methodology

The methodology used to develop the final OMS/GIS cost benefit and supporting information presented in this report follows a classic information technology approach of assessment, requirement and solutions definitions. Cost and benefit models were then developed based on this information and a final cost benefits and roadmap is produced.

The following, Figure 3-1 is an overview of the assessment methodology and approach that KEMA has applied to this project to develop the OMS/GIS cost benefits.

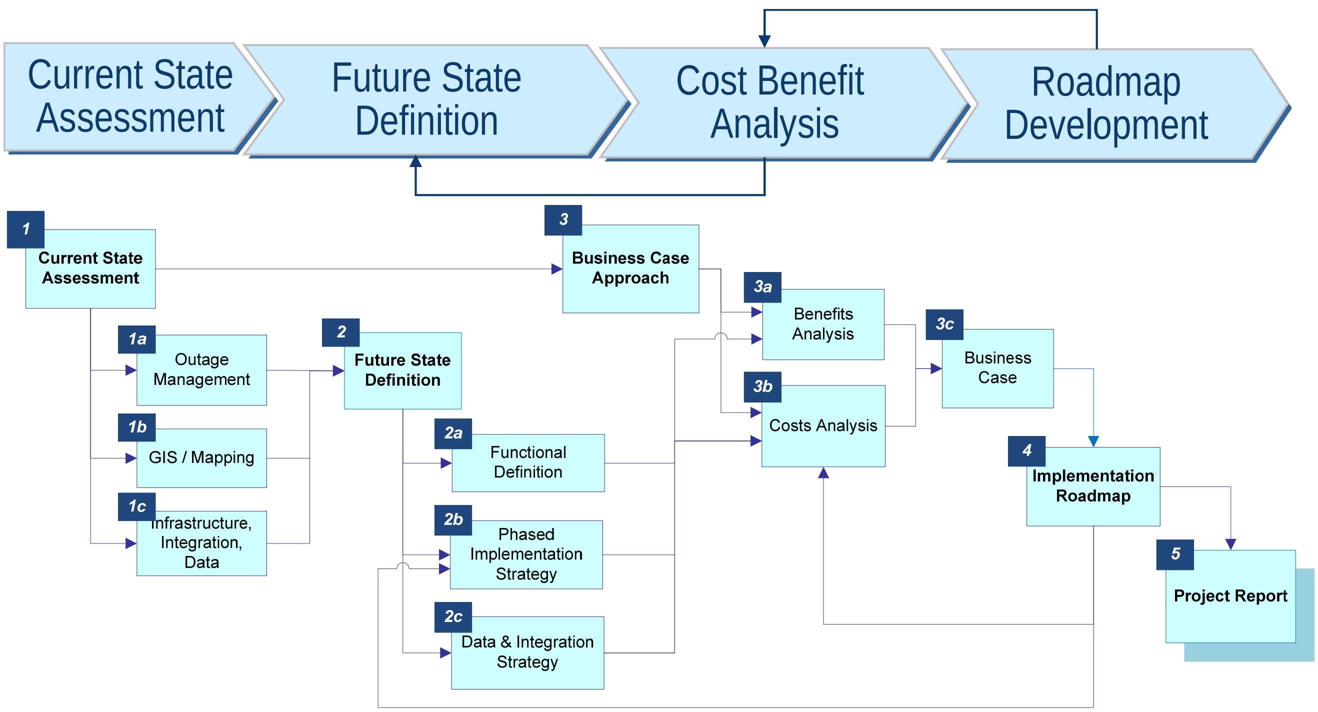

Figure 3-1 Cost Benefits Assessment Methodology

There are four major steps in this project methodology:

1. Current state assessment – Review the capabilities and limitations of the existing PSE processes and information systems used for outage management;

2. Future state definition – Define the future state system architecture based on PSE business requirements and industry standards;

3. Assessing the Costs and Benefits – Define the cost and benefits models and perform the financial analysis of the business case; and,

4. Developing the roadmap – Define the implementation approach for the recommended technologies and process improvements.

3.1 Current State Assessment

In the current state assessment, existing functional capabilities and processes, as well as information systems and automation functions, were reviewed at a high level in the following areas:

1. Outage Management – all aspects of outage notifications, outage assessment, development of a tactical plan for service restoration, scheduling and dispatching of resources, service restoration, restoration verification, and outage reporting.

2. Customer Services and Field Operations – including trouble call management and field crew dispatch and support.

3. Maps and Records Management – existing mapping capabilities and processes for updating maps to reflect the as-built configuration of the system, the use of maps in system design and system planning, and electric connectivity data needed to support an OMS.

4. Current IT infrastructure and integration framework – existing middleware that could be used for OMS/GIS integration, existing IT guidelines, standards, and strategic directions for integration of operational systems with enterprise applications.

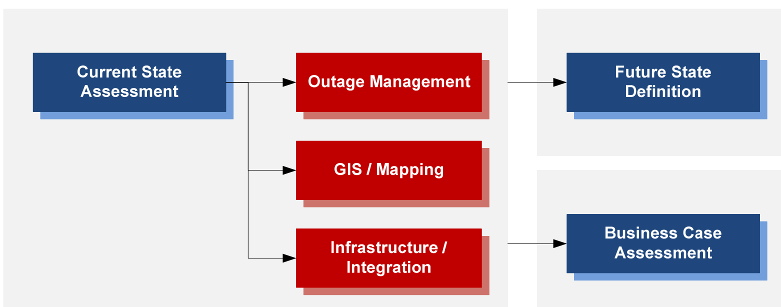

Figure 3-2 Current State Assessment

3.2 Future State Definition

The future state for outage management is defined in the following areas:

1. Functional Definition – The business requirements for OMS and the GIS requirements to support the OMS. The business requirements are grouped on business priorities. Based on these business requirements a set of functional and system requirements are derived. The functional and system requirements will drive vendor package evaluation and the procurement decision.

2. Phased Implementation – The methodology which favors a phased approach to implementation of OMS and GIS as opposed to a single large implementation approach. There are many advantages to a phased approach, namely, the ability to deliver value to the business in short term and mid-term intervals. The business does not have to wait for an entire multi-year project to be completed before any value is realized from the technology investment.

3. Data & Integration Strategy – Aligning the program's data management and integration strategy with the corporate IT policies and guidelines in these areas. In some areas it will be necessary to define the integration and information management strategy if none exists.

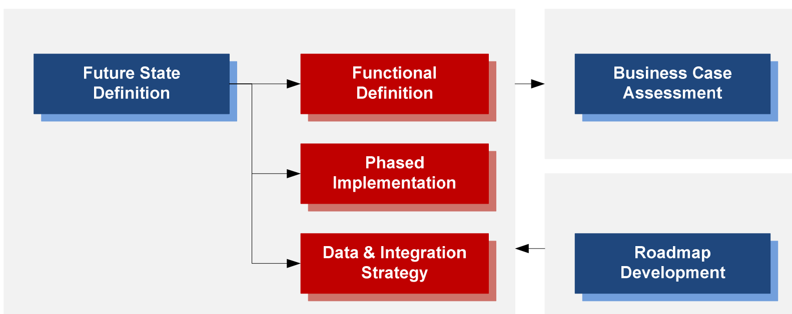

Figure 3-3 Future State Definition

3.3 Cost Benefit Analysis

The evaluation of costs and benefits, and the program's NPV were prepared along the following lines:

1. Benefits Analysis – A qualitative and quantitative evaluation of benefits to PSE, considering efficiencies in Operations and Maintenance (O&M) and capital expenditures. The analysis reflects specific improvements at PSE while considering industry experience and benchmarks. The benefits analysis also includes the calculation of societal benefits; however, those are not included in the project's NPV calculations.

2. Costs Analysis – All capital costs and O&M costs for hardware, software, and labor, including internal PSE resources and external resources for professional services.

3. Business Case – The calculation of NPV for the program over a 15-year time span.

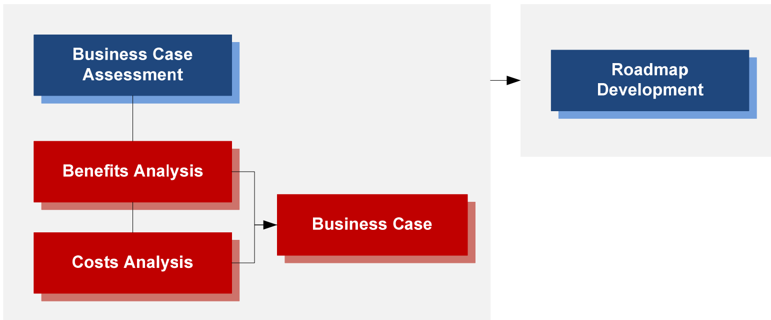

Figure 3-4 Cost Benefit Assessment

3.4 Implementation Roadmap Development

The business case and project costs are functions of the implementation schedule and approach. A considerable level of activity coordination is required for the phased implementation of this project. The development of the implementation roadmap is an iterative process that adjusts the timing and resource requirements of project activities with due consideration for business priorities, dependencies, and timelines. This process is repeated in collaboration with all stakeholders until an agreed to plan can be developed.

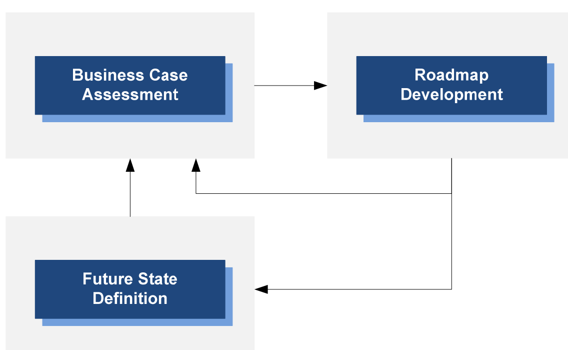

Figure 3-5 Implementation Roadmap Development

4. Current State Assessment

As previously mentioned in Section 2, KEMA has performed a post-event assessment of the December 14-15, 2006 storm and documented the findings and recommendations. The current state assessment documented in this report ties the critical issues and recommendations made as a result of that post storm assessment to functional requirements that are needed for an OMS and related process improvements necessary for PSE to manage outages effectively.

As part of the cost benefit assessment, KEMA conducted a series of meetings with key PSE staff and teams to assess the following:

- The current state of information technology systems used in the management of outages;
- The current state of outage management processes and identification of business requirements that drive the need for an outage management system and related process improvements; and,
- The limitations of current IT systems in support of outage management.

4.1 Current State of Information Technology Systems

A review of the current systems at PSE that support outage management processes was made. Figure 4-1 is a high level illustration of the key PSE information systems in place for the logging, analysis, communicating, and reporting of outage events.

The key components of current system capabilities at PSE for outage management include:

- **ConsumerLinX (CLX),** a high-transaction customer information system designed around PSE business needs. In addition to customer service and billing functionality, CLX also includes some capabilities to support outage management and restoration processes. CLX generates outage orders for every customer-reported outage, and is the main information system supporting PSE's outage restoration process.

  Currently, CLX provides both customer information and trouble call processing functionality through the IVRU. CLX also provides customer specific status of an outage. CLX receive outage status data from PSE's Distribution Management System (DMS) via an automated interface. Meter data is also available to customer service representatives using CLX, however, the Advanced Metering Infrastructure (AMI) interface was not designed to provide real-time access to meter status and last-gasp outage information.

CLX is integrated with an IVRU for customers to receive general outage messaging and specific outage status. The system can also make automated callbacks to confirm service restoration. This capability was fully utilized during the December outage, with some congestion and processing delays due to volume of incoming calls. CLX is also integrated with an application called Distribution Data Display (DDD) for graphical display of outage information on a circuit basis. This allows outage events to be segmented during the course of a circuit outage for assigning repair crews and providing more specific restoration time estimates.

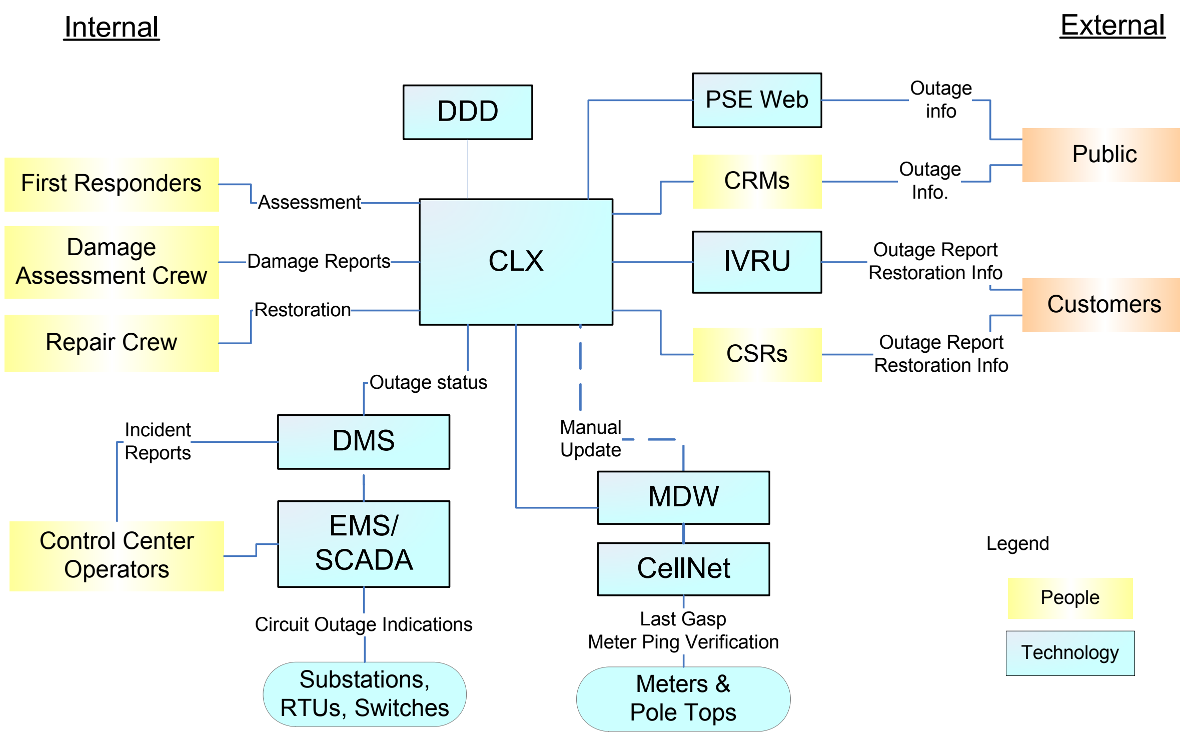

Figure 4-1 Overview of PSE IT Systems for Outage Management

- **IVRU** – used for customers to report outages and to receive general outage messaging and outage status during outage events.

- **EMS/SCADA** – Used at the System Operations control center, EMS/SCADA also played an important role in the outage management process. The storm resulted in damage to the transmission lines and left entire substations off-line with many full-circuit distribution outages. By monitoring the status of the transmission system using EMS/SCADA, control center dispatchers detected and reported such outages in a very timely manner. Dispatchers also continued to use EMS/SCADA to monitor the status of the system during the restoration process and provide oversight and direction for the re-energization of transmission lines once field repairs were completed.

- **AMI** – the AMI system provides functionality to support the outage detection and restoration processes. The AMI meters and pole-tops report a signal when they lose and regain power. The AMI system is supported by a meter data warehouse and includes a limited web-based outage map and outage summary dashboard. The AMI system also includes an application for interrogating individual or groups of meters to verify power operation. The massive volumes of outage data generated during the early stages of the December 14-15, 2006 Storm overloaded the AMI system compromising its effectiveness for outage detection and reporting. Also, storm damage affected the AMI's ability to effectively communicate meter status.

- **DMS** – The DMS functionality at PSE is limited to tracking/managing distribution switch statuses and changes, device tags (Danger do not operate, Hold, Abnormal, etc.), Clearances, Work Orders, Reconnects, and Service Requests organized into Incidents, which can be outages. All information is manually entered into the system. On a daily basis, the system automatically emails the previous day's incident logs to a general repository for viewing. There is very little in the way of remote telemetry and automated devices on the PSE distribution system except for some substation device monitoring, and selected distribution automation functions at some key locations and C&I customer sites. As such, the DMS application at PSE does not include SCADA integration and real-time field status monitoring. It is expected that the current DMS functionality will be absorbed by the OMS.

4.2 Outage Management & Restoration Process

The flow of outage management information at PSE today generally (at a very high level) follows the process below:

- Calls from customers of "lights out" are taken by CSRs in the call center and then recorded in CLX, or recorded automatically by the IVRU and sent to CLX.
- System Operations (Dispatcher or System Operator) receives, via a printer, outage notifications, one per customer call for the first 5 callers for the same circuit; this could be for different outages, but is difficult to determine. After 5 customer call notifications additional ones are not received unless new significant information provided.
- The outage notifications are reviewed. If emergency level information is provided the First Responder is immediately dispatched otherwise system operations may wait for more notifications before dispatching anyone.
- A First Responder is dispatched to the outage location and performs an assessment of the outage cause. He may also provide the dispatcher with the estimated time to restore.

- This information is entered into CLX for use by the customer call center and other PSE management.
- The outage cause is corrected and power is restored.
- This information is then updated in the CLX.
- Restoration may be validated by customer call backs and by validation of power at AMI pole top units.

Limitations to this current process are summarized below and elaborated later in this section.

- There are numerous manual data entry points and manual information hand-offs;
- Delays in the process in turn delay information dissemination throughout the organization and to customers;
- The technologies that support the outage process do not enable effective and efficient data flow and analysis;
- During high-customer call events such as storm conditions, the process and technologies are not effective to manage the high volume of information; and,
- Lack of integration between key IT systems requires manual data transfers and result in process delays.

4.3 Limitations of the Current Systems and Processes

Examination of current PSE processes based on the results of the December 2006 storm assessment identified some very specific challenges and limitations that are shown in Table 4-1 that relate to technology, information, and process. Reference refers to the original report's section number.

Table 4-1 PSE Outage Management Issues

Issues identified in the "2006 Storm Restoration and Readiness Review"	Ref.
Relay better information about restoration time as each post-storm day passes. Quality of information did not improve with time. Lack of a system that provides updated outage and restoration information.	7.3.2
Coordination of Operations Base activities and the EOC are sometimes strained and counterproductive	7.3.6
The abundance and backlog of requests for clearances delayed crews in the initiation of repairs.	7.3.8
PSE provided consistent customer messages, but customers needed more localized information.	8.3.1
Instead of waiting for a definitive damage estimate, PSE should communicate the severity of outage to customers sooner.	8.3.2
Responsibility for communication with critical customers, such as key customers, the media and municipalities was not consistently executed.	8.3.5
The Customer Call Center at PSE should have access to information requested by customers.	9.1
PSE augmented its call center staffing to handle inbound calls.	9.3.2
PSE's inbound call system does not automatically generate individual restoration estimates.	9.3.6
Due to incomplete restoration information, CSRs could not provide many customers with timely and accurate restoration estimates.	9.3.8
CLX is a customer information system that has limited outage management functionality.	10.3.2
PSE has no automated technology to "roll-up" outage restoration information from the field to the EOC.	10.3.3
The damage assessment reports can not be summarized into meaningful management information.	10.3.4

Some of the key issues above are further elaborated in the following.

PSE has no automated technology to "roll-up" outage and restoration information from the field to the Emergency Operations Center (EOC).

It is essential that PSE management have clear and timely summary information about restoration efforts during major outage events. This information flow begins at the field crew level and works its way back to the Operations Base and then to the EOC. Once the EOC has the necessary information, it can be communicated and used to evaluate progress, inform PSE management, and inform customers.

Field data volume overwhelmed several PSE Systems, and therefore data was not consistently collected or transformed into usable information.[2,3]

PSE information systems provide adequate functionality and performance in support of a typical storm where there are manageable numbers of trouble calls and outages. System limitations are generally overcome by manual operations. The sheer volume of data produced during the December 14-15 storm, however, overwhelmed these systems and the manual data entry could not adequately support the process in a timely fashion. Furthermore, certain data integration links and communication points were not designed to handle the large volumes of data transactions during the short time frame of the storm event.

Due to unavailability of data, the CLX customer system could not provide adequate information support to CSR's in the customer call center and to other personnel within PSE in response to customer inquiries, contractor resource scheduling needs and for the dispatching of required field resources.

The IVRU system was sporadically overloaded due to the volume of incoming trouble calls. The AMI system was crippled with both a large number of simultaneous outage reports and loss of power and thus was not able to successfully report meter outage information.

CLX is a customer information system that has limited outage management functionality.

CLX connects a customer account to an electric circuit identifier. CLX also provides basic functionality needed to capture trouble calls, identify outage circuits, capture restoration time, and track status of the restoration process. During an outage event, CLX is the key system for capturing outage related data and for providing information needed by CSRs when responding to customer trouble calls. CLX itself, however, was not designed to provide summary level circuit outage information or reports.

Due to limited integration with other systems, CLX requires extensive manual data entry when supporting the type of outages experienced during the December 14-15, 2006 storm. PSE's ability to communicate with customers is severely limited when CLX data is not consistently entered and updated due to a limited numbers of personnel qualified to enter data into CLX during a major event.

CLX is labor intensive due to:

- The cumbersome nature of CLX data entry requirements;

[2] Source: AI01, 02, 03
[3] KEMA Principals' Distribution Application Experience

- Field processes and CLX system processes are not fully integrated and synchronized;
- Limitations in transmitting meter outage reports from the AMI system;
- Lack of a system connectivity model in CLX that amplifies the need for manual data entry; and,
- Limited integration of SCADA information with CLX through DMS.

The damage assessment reports cannot be summarized into meaningful management information quickly during major outage events.

Damage assessment information is phoned to the Operations Base where it is recorded on a form, the Storm Board and in CLX. The completed forms are manually filed and kept near the Storm Board. As results are recorded on the Storm Board, completed forms are returned to the file and inserted in a different alignment to enable Storm Board personnel to track what has been recorded.[4]

A CLX specialist will enter the form information into CLX by circuit and customer. This creates a permanent record inside of CLX. However, there is no way of summarizing the information in CLX to quickly provide management with a clear and complete picture of individual circuit damage. Anyone outside of the Operations Base needing information has to search for each record tied to that specific circuit in CLX. Alternatively, management would have to call the Operations Base directly to obtain the information. While the latter is possible it distracts Storm Board personnel from restoration efforts.

4.4 Spatial Data Management – Maps and Records

A discussion of spatial data is necessary because the OMS requires access to an accurate electric network of the operating system. Generally this information is maintained in the GIS, whose source data are current facility maps (assets and land base).

Currently, PSE does not have a GIS. The current system of maintaining maps and records that contain spatially referenced data is a manual process with limited tools. The format of facility and land data needs to be in a format that can support an OMS. There are, in addition to OMS, a significant number of other reasons to implement a GIS to support PSE's geographic plant asset management functions.

Currently, the user must individually search through various sources of information systems to find the complete picture about PSE's facilities. With a GIS implemented, much of this information will be

[4] Source: RG03, 08, BS08

replaced by the geospatial database or accessible through links to this database to be viewed, queried, mapped, and analyzed.

Current limitations with the mapping and records processes and tools include the following:

- Multiple land bases and facility records to maintain;
- Multiple data entry due to the multiple land bases and facility records;
- Raster format of data makes it unsuited for data analysis and the ability to support systems that require vector network data;
- Important facility data is scattered among different sources including cards, different maps, and paper records;
- The format of map data makes it difficult to share this data internally and externally;
- Data is not complete (e.g., services missing, easements and rights of ways not identified) and not updated in a timely manner;
- Data is not in a format to support applications like asset management, planning and design and system analysis;
- Manual data format make it difficult to use this information during emergency situations and to get data into the field in a usable format; and,
- Inaccurate and untimely data sources may pose safety issues for field personnel.

Under storm conditions, by far the greatest feedback received from personnel who worked in the field, was that current facility maps do not show how to physically access certain critical devices such as circuit switches. Information about transmission rights of way and access to PSE facilities is vital during emergency conditions and need to be provided to field personnel during storm conditions as well as under normal operating conditions.

4.5 Conclusions

The current state assessment of PSE processes and technologies used for the management of outages has identified limitations, particularly in regard to the lack of an outage management system and process improvements that can take advantage of OMS functionality. These limitations become very apparent when significant outage events, such as storm conditions, occur. These limitations will be addressed in the next section on future state recommendations.

These process and system shortcomings can be summarized as follows:

- There is a need for system functionality that will allow for the efficient logging of reported outage events through a variety of media;

- There is a need for a system to perform outage analysis based on customer calls;
- There is a need to provide ready access to, and disseminate outage information to the PSE organization;
- There is a need to provide status updates to the Customer Call Center and to others within PSE;
- There is a need to communicate outage status information to the media, public agencies, and municipal organizations;
- There is a need for effective management and coordination of clearances; and,
- There is a need to use outage data for analysis and reporting.

Key recommendations of the KEMA Post-Storm Assessment report[5] with respect to information technology capabilities are summarized in Table 4-2 below, with reference to the post storm assessment report's sections.

Table 4-2 PSE Storm Management Issues

Issues identified in the "2006 Storm Restoration and Readiness Review"	Ref.
The lack of an outage management system severely hampered the efficiency of the restoration process.	10.3.5
Establish enterprise-level technology, data and integration architecture for outage management related processes.	10.4.1
Develop end-to-end information and business process flows for outage management and emergency restoration processes	10.4.2
Enhance existing technology and systems to close functionality gaps and with the strategy of migrating them toward the final architecture.	10.4.3
Deploy new systems to close the functionality gaps and build out the outage management architecture.	10.4.4
Develop a phased implementation plan for outage management related information systems and processes.	10.4.5
Infrastructure Conditions: Vegetation Management Program Improvements	14

These recommendations are further elaborated below:

[5] KEMA Windstorm of December 2006 Storm Restoration and Readiness Review

The lack of an outage management system severely hampered the efficiency of the restoration process.

CLX and the supporting PSE information systems that were used in the storm event have certain critical functional limitations when compared with leading industry practice outage management systems because they were not designed to serve as outage management systems. These system limitations are particularly evident when dealing with major storm scenarios involving a large number of outages.

They include the lack of:

- An electric distribution circuit predictability model that associates customer outages with the physical location on the distribution system;
- Business rules that allow for the effective management of large scale outages and restoration efforts including status of estimated time to restore;
- Integration to a SCADA/EMS system for real-time system status updates within the current CLX system;
- Automated outage analysis to assist in crew scheduling and dispatch; and,
- Capability to automatically provide status updates through a variety of media including pagers, cell phones, E-mail and dash boards.

Establish enterprise-level technology, data and integration architecture for outage management related processes.

This recommendation is based on the premise that increased automation will improve the outage management process. KEMA recommends that PSE undertake the following activities:

- Develop a data architecture that shows how data will be organized, exchanged and shared;
- Develop an integration architecture that shows how various systems and applications interoperate; and,
- Develop a technology architecture that shows how the underlying computing and communications platforms support the business applications.

Develop end-to-end information and business process flows for outage management and emergency restoration processes.

KEMA recommends that PSE perform the following activity:

Perform a business process analysis of processes related to outage management and produce end-to-end process charts that define:

- Process tasks, roles and responsibilities along the process thread;
- Flow of information and communications;
- Functionality required of enabling systems that support process tasks; and,
- Data requirements and data stores.

Then use this information to define IT system functional and data requirements, perform process improvements, and integrate enabling systems to processes.

Enhance existing technology and systems to close functionality gaps and with the strategy objective of migrating them toward a final architecture.

KEMA recommends PSE perform the following activities:

- Establishing an approach for the integration of SCADA data and key alarm conditions with other systems such as OMS and make interfaces available for such integration;
- Consider expanding distribution automation capabilities on key circuits at the substation level to support automated switching and restoration processes;
- Bridging functionality and reliability gaps of the CellNet AMI system to support outage reporting and restoration verification;
- Utilizing proven consumer technologies in support of restoration management and emergency response functions;
- Evaluating and implementing the use of low-cost consumer technology like digital cameras and GPS devices; and,
- Using local carrier phone network in front of CLX/IVRU to enhance call-taking capacity, and capabilities.

Deploy new systems to close the functionality gaps and build out the outage management architecture.

New systems and applications are needed to bridge functional gaps that exist in support of emergency restoration processes. KEMA recommends PSE perform the following activities:

- Perform process analysis of outage management business processes and define needed OMS functional requirements;

- Select and implement a commercial OMS;
- Migrate existing outage management functionality from CLX to the new OMS;
- Integrate the new OMS functionalities with appropriate PSE systems and processes;
- Select and implement a GIS system that includes;
- Migrate existing raster facility maps to the new GIS System;
- Perform data conversion and define the electric circuit connectivity models needed to support the OMS;
- Implement an electronic storm board with information overlay from SCADA, OMS and AMI; and,
- Select and implement automated switching and restoration workflow tools for distribution where it makes sense and is cost effective.

Develop a phased implementation plan for outage management related information system and processes.

Establish an enterprise data and integration architecture, enhance existing systems, and deploy new technologies. A phased implementation of these activities will take several years and a roadmap should be established to guide this effort. The following considerations should be incorporated in development of this roadmap:

- Identify immediate and high-value items that can be implemented in a short time period, synchronized to yearly storm seasons;
- Implement key foundational elements of the architecture to support the interoperability and integration goals;
- Identify the interdependencies of all projects;
- Migrate existing systems and processes to the new capabilities without business disruption;
- Integrate data; and,
- Identify resource constraints and budget requirements.

5. Future State Recommendations

The cost benefit analysis performed by KEMA concludes that implementation of a full function commercial OMS will address PSE's outage management requirements, and that a commercial GIS is needed to support the OMS.

This section discusses these recommendations showing how the solution addresses the gaps and issues identified in the KEMA report on 2006 Storm Restoration and Readiness Review, and how the proposed technology components should be integrated with existing PSE systems and processes.

5.1 Capability Mapping

The OMS/GIS technology solutions are key components of a broader set of capabilities that address the recommendations made in the KEMA storm assessment report[6]. These recommendations and proposed solutions are summarized in the following Table 5-1.

Table 5-1 PSE Outage Limitations and Potential Solutions

Issues identified in the "2006 Storm Restoration and Readiness Review"	Ref.[12] Sec.	Recommendation	Specific Solution(s)
Relay better information about restoration time as each post-storm day passes. Quality of information did not improve with time. Lack of a system that provides updated outage and restoration information.	7.3.2	An integrated OMS will consolidate outage and restoration status and provide that information to the Customer Service Center and to key PSE management.	OMS, Outage Data Mart, CIS, Process Re-Engineering
Coordination of Operations Base activities and the EOC are sometimes strained and counterproductive	7.3.6	Implementation of proper tools and processes will help in the transfer of consistent and updated information between the EOC and Operations Bases to improve coordination.	OMS, Executive Dash Board, Map Board.
The abundance and backlog of requests for clearances delayed crews in the initiation of repairs.	7.3.8	The OMS will have planned switching capability to generate switch plans and allow the dispatcher to record steps as they are relayed from the field to help manage clearances. It also includes a library of switch plans and the capability for power flow analysis.	OMS (planned switching, power flow)

[6] KEMA Windstorm of December 2006 Storm Restoration and Readiness Review

Issues identified in the "2006 Storm Restoration and Readiness Review"	Ref.[12] Sec.	Recommendation	Specific Solution(s)
PSE provided consistent customer messages, but customers needed more localized information.	8.3.1	The quality and timeliness of damage assessment and restoration is dependent on the field damage assessors and the System Operations department. The OMS, however, can consolidate all information together for specific circuits, regions or geographic areas for informing customers.	DA Tool, OMS
Instead of waiting for a definitive damage estimate, PSE should communicate the severity of outage to customers sooner.	8.3.2	The future state information flow is from the Damage Assessors in the field to an Outage Data Mart, to the OMS to the CIS. Information can be updated and improved along the process thread, until definitive information is provided to the Call Center via the OMS.	DA Tool, Outage Data Mart, OMS, CIS and Process Improvements
Responsibility for communication with critical customers, such as key customers, the media and municipalities was not consistently executed.	8.3.5	The OMS will provide current and consistent information to key PSE employees that deal with key customers (Account Executives), the media (Public Relations), and those responsible for coordinating with municipalities and public agencies.	OMS (Service Alert, Executive Dash Board)
The Customer Call Center at PSE should have access to information requested by customers.	9.1	The OMS integrated to the CIS will provide outage and restoration information and status updates for use by Customer Service Representatives. The OMS can also update the IVRU with status information.	OMS, CIS, IVRU
PSE augmented its call center staffing to handle inbound calls.	9.3.2	OMS software have a module called web call entry where temporary call center workers can enter outage events directly into the OMS.	OMS (Web Call Entry)
PSE's inbound call system does not automatically generate individual restoration estimates.	9.3.6	An OMS can provide information selectively to the CIS and IVRU by geographic areas or regions familiar to customers with the outage and restoration information specific to customers calling in for outage reporting or status inquiry.	OMS, CIS, IVRU

Issues identified in the "2006 Storm Restoration and Readiness Review"	Ref.[12] Sec.	Recommendation	Specific Solution(s)
Due to incomplete restoration information, CSRs could not provide many customers with timely and accurate restoration estimates.	9.3.8	Restoration times must be established and entered into the OMS for transfer to the CIS and IVRU. While the OMS cannot establish the estimated time to restore power, it can provide the granularity for providing restoration estimates by circuit and, hence, by geographic area for customer information. Revisions to ETR are also entered into the OMS and conveyed to the CIS. Secondary outages and pocket outages can be verified by "pinging" AMI meters or pole top communications units.	DA Tool, Outage Data Mart, OMS, AMI, CIS, IVRU and Process Re-Engineering.
CLX is a customer information system that has limited outage management functionality.	10.3.2	Implement a commercial OMS to replace the limited outage management functions currently in CLX.	OMS
PSE has no automated technology to "roll-up" outage restoration information from the field to the EOC.	10.3.3	The solution is a combination of process re-engineering, practices and tools to enable proper communication along the entire process thread for outage and restoration management.	DA Tool, MWF, Outage Data Mart, OMS, Process Re-Engineering
The damage assessment reports can not be summarized into meaningful management information.	10.3.4	In a severe storm condition with many damage assessors in the field, the verbal information flow from the field to the EOC will bottleneck at the personnel who will be entering this data into a system. By having damage assessors enter information directly into a mobile data terminal connected to a mobile workforce management (MWF) system that is also integrated to the OMS, the information is conveyed electronically into the OMS.	DA Tool, MWF, OMS, CIS
The lack of an outage management system severely hampered the efficiency of the restoration process.	10.3.5	The OMS is designed to perform outage analysis.	OMS
Establish enterprise-level technology, data and integration architecture for outage management related processes.	10.4.1	Develop the data architecture, integration architecture, and technology architecture for outage management.	OMS/GIS Roadmap and Integration Strategy

Issues identified in the "2006 Storm Restoration and Readiness Review"	Ref.[12] Sec.	Recommendation	Specific Solution(s)
Develop end-to-end information and business process flows for outage management and emergency restoration processes	10.4.2	Perform process charting and analysis of all business flows related to outage management, restoration management and the communication of outage information.	Process analysis
Enhance existing technology and systems to close functionality gaps and with the strategy of migrating them toward the final architecture.	10.4.3	Implement distribution automation and distribution management system, integrate SCADA to OMS, implement the outage data mart and interface to the AMI meter data warehouse.	Outage data mart, meter data warehouse, OMS, SCADA, DA, DMS
Deploy new systems to close the functionality gaps and build out the outage management architecture.	10.4.4	Select and implement the OMS, electronic storm board, and integration strategy.	OMS
Develop a phased implementation plan for outage management related information systems and processes.	10.4.5	Develop the OMS Implementation Roadmap	OMS/GIS Roadmap and Integration Strategy
Infrastructure Conditions: Vegetation Management Program Improvements	14	A geographic information system (GIS) with applications to show rights-of-ways, easements, access roads and facilities will aid in managing transmission rights-of-ways. A vegetation management application will allow for the planning, scheduling and recording of vegetation work along transmission and distribution corridors.	GIS with vegetation management and ROW applications for electric transmission and distribution.

5.2 The Phased Solution

KEMA recommends a three phased approach for the implementation of the OMS and GIS, and the supporting capabilities at PSE. The three phases are:

- **Outage Data Mart**. Develop and implement an Outage Data Mart (ODM) in time to support the 2008 year storm season. The ODM brings together the many outage and restoration data sets and formalizes the query, management and access process to this data. The intent is to leverage existing PSE data sources and systems and to augment them with new capabilities to provide an aggregate source of information for operations support, improve estimation of restoration times, and support communication and reporting of outage status information for internal and external purposes. The ODM will include capabilities for consistent collection and management of damage assessment reports, and will provide data mining capabilities for forecasting and estimations.

- **Base OMS Function**. The second recommended phase is to implement a base OMS in time for the year 2009 storm season. The OMS will be commercial software that will meet PSE business needs for outage management while being highly configurable. It will provide the functionality needed to manage unplanned outages for normal and storm conditions. Although it is theoretically possible to manage planned outages through OMS at this stage, this capability will likely not be achievable until the next phase due to other dependencies including the need for higher quality data, ability to do power flow analysis, and the ability to record the switching clearance steps as they occur in the field which in turn requires integration of OMS with MWF. Due to the need for very accurate facility data for planned switching, and the added complexity of planned switching and power flow applications, KEMA recommends that this capability not be implemented with unplanned outage management.

  In order to support the OMS, a commercial GIS is needed to provide the electric distribution network connectivity information for outage analysis and for restoration management processes. Figure 5-1 illustrates the basic phasing of the recommended functionality and the relationship of the new capabilities with the existing PSE systems. Implementation of the GIS in this phase will be limited to that which is needed to support the OMS. Data and functionality will also be provided, however, to support transmission vegetation management.

- **Advance OMS Functionality**. The third phase will provide additional outage management functionality, including planned switching, clearance management and power flow analysis. Integration to the MWF system will provide the ability to dispatch trouble orders to the field efficiently, to receive status reports, estimate times for restoration, and coordinate and manage clearances. This phase is planned for the year 2010 storm season. The planned switching and power flow analysis functionality requires very accurate facility connectivity and phasing data. It is for this reason that these functions have been pushed off into this phase to allow sufficient time to clean GIS converted data and to ensure that the data is of sufficient quality to support planned switching.

  During this phase and beyond, additional GIS functionality can also be developed and implemented to leverage the GIS tool to provide support to engineering, system planning, system maintenance, system operations, field functions, and asset management for both gas and electric. It is recommended that PSE leverage the base GIS package implemented in support of the electrical outage management with an incremental set of functions to provide a complete GIS capability for electric and gas applications. This capability will replace the existing PSE raster CAD drawing-based maps with a best practice GIS application.

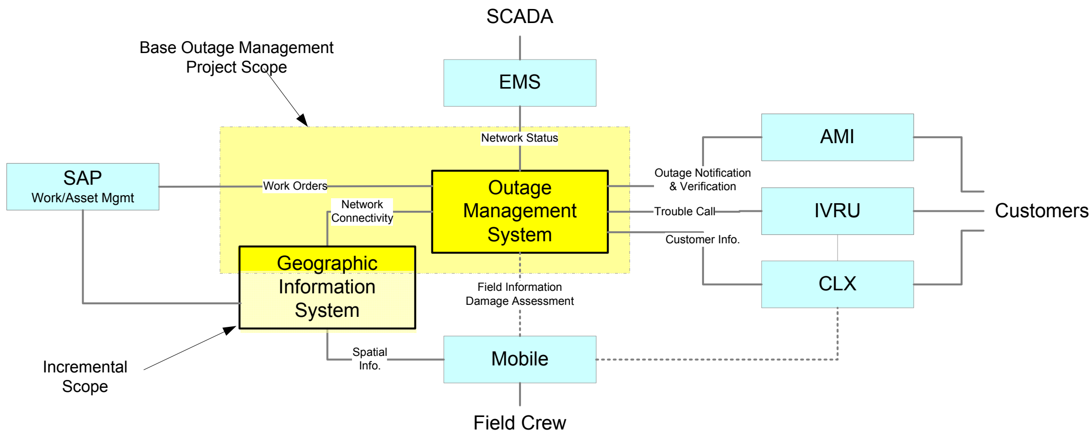

Figure 5-1 OMS & GIS Phased Implementation

A phased implementation of the OMS and supporting GIS capabilities will deliver the needed business capabilities in as short a time as practical while mitigating the risks associated with wholesale deployment and integration of multiple IT systems and the corresponding process reengineering and change management activities. The phased approach affords the possibility of building the long term solution without imposing undue delays in providing PSE with the more essential elements of the outage management solution.

5.3 The Outage Data Mart

The ODM system is an early delivery to close some of the existing information communication and information management gaps associated with the outage management process. The capabilities proposed will support and complement the broader OMS functionality that will be rolled out in 2009 and 2010. The ODM includes certain capabilities for data management, data access and transformation, as well as procedures and methods for collection, management and archival of certain data, reports and information associated with outage events and restoration process that are not typically managed in an OMS and/or are essential for the support of the outage management process while the full OMS being implemented.

Broadly speaking, the PSE ODM is envisioned to provide the following capabilities:

- **Damage Assessment:** Data management, archival and reporting capabilities needed for support of the Damage Assessment tool that is being scoped and implemented at PSE. The ODM will provide database management, user interface, data mining, and decision support capabilities needed to collect, store and analyze current and historical damage assessment reports based on various user selectable criteria. For example, direct observations from the First Response teams in the field can be correlated against historical records of similar outage events in the past as a basis for a more informed estimation of service restoration times and level of damage.

The historical Damage Assessment information when combined with other related data, e.g., weather conditions, equipment and facility type and condition, vegetation information, level of effort for damage repair and restoration time, can be used for forecasting the impact of future and pending storms, and help in future planning and preparation for storm conditions.

- **Outage Dashboard:** Certain capabilities have already been developed for bringing together data from various sources, including CLX through the Meter Data Warehouse, and information from the CellNet AMI system to create a summary outage status display and to provide graphical display of known outage conditions over the PSE service territory maps using the CellNet meter and pole-top device status reports. The ODM will be built upon these capabilities and will formalize, harden, and expand the current Outage Dashboard capabilities in a fashion that can be effectively utilized by PSE staff and crew in support of the outage management and restoration process.

  This function can be combined with future capabilities provided by the OMS to provide more comprehensive Executive Dashboard capability to presents an up to date status of the outage and restoration activities based on the most recent data from IVRU, the AMI system, SCADA and other sources of data, combined with the GIS spatial maps. The data will be analyzed and presented in a way that can be viewed in various depth and breadth. The user will be able to view a broad picture of the outage event and be able to look at more detailed data in any specific area, as needed.

- **External Communications:** The ODM will provide capabilities for managing key information and communication messages and status reports associated with an outage condition. The ODM will act as a virtual central repository that aggregates outage related information, and serve as the common source of up to date information associated with an outage condition that can be used for internal and external communications. The information is targeted for PSE's Public Relations staff, customers and public, the regulators, the media, and other emergency services.

  The ODM will also provide data and report archival capabilities for maintaining an audit trail and an archival of communications messages, reports, and other information made available externally. The ODM will also act as a document management system to the extent that it will store past copies of externally communicated outage related information (e.g., press releases, news articles, etc.).

- **Outage Data Analysis:** Provide mechanisms for data analysis and reporting – with data aggregated in the ODM system, additional data analysis and reporting capabilities will make it possible to utilize that information for the needs of different users. The reporting and analysis capabilities could be provided through specialized engineering analysis tools and/or standard reporting tools that simply reformat the data for presentation to users.

Figure 5-2 is a conceptual illustration of the recommended ODM capabilities in relationship to other existing PSE systems.

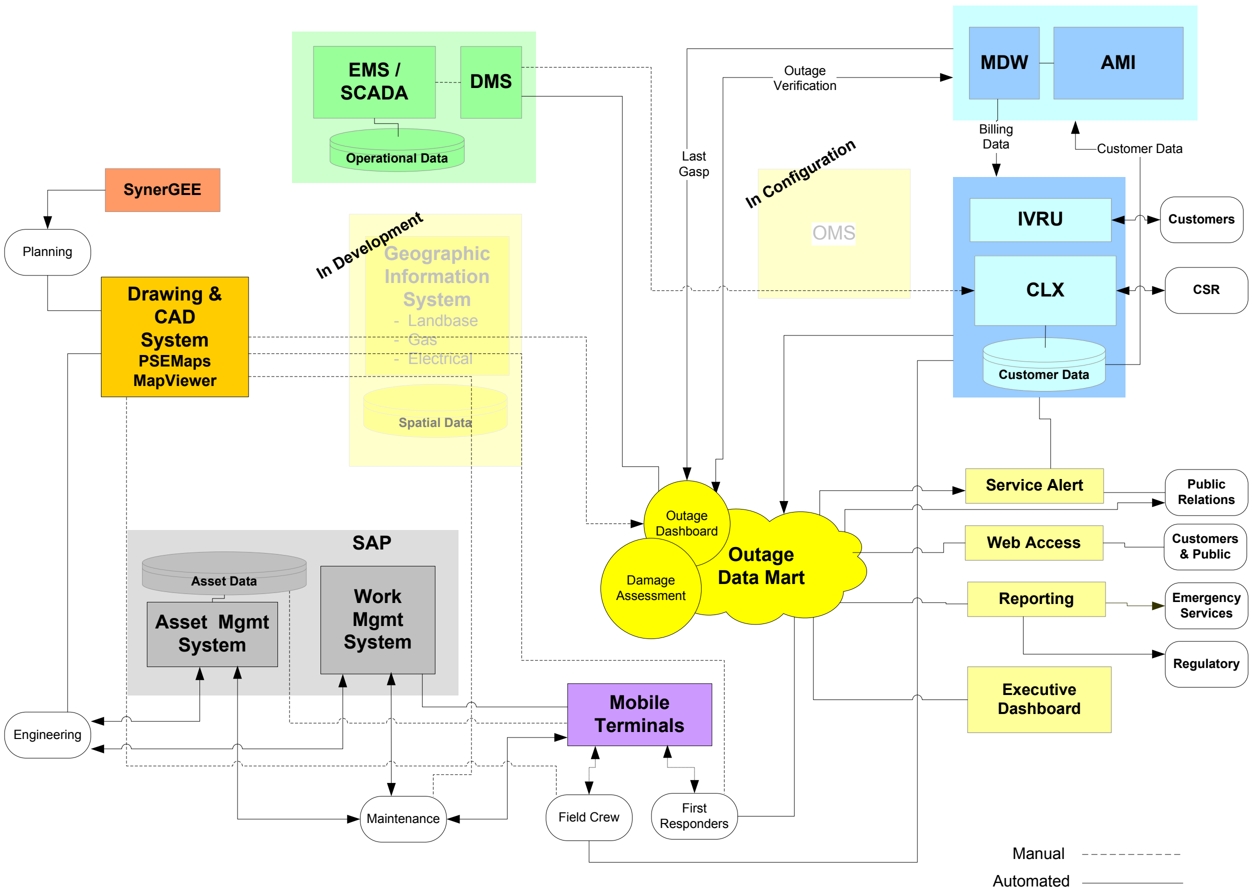

Figure 5-2 Outage Data Mart (ODM) System

5.4 The Outage Management System (OMS)

This report recommends the replacement of the current outage management capabilities of CLX with a best-practice commercial OMS solution.

The OMS will maintain an up-to-date distribution system connectivity model that reflects the current operating configuration and state of the electric system. Reported outages are analyzed against the system model compared to the current operating status of key equipment, e.g., substations, transformers, and switches.

The OMS has business rules which allow the efficient management of large scale outages and restoration efforts. Proper integration of key systems, including CIS, IVRU, EMS/SCADA, and MWF significantly reduces the need for manual and redundant data entry and allows efficient transfer of data to those who need it. The SCADA/EMS system supplies valuable real-time information about operating conditions and system configuration. When combined with the OMS connectivity model, circuit outages can be quickly identified and outage reports mapped and analyzed.

The OMS provides a library of planned switching scenarios that the switching coordinator uses to manage clearances. Restoration procedures and processes can also be defined in the OMS to help with large-scale distribution outage restorations. The procedure defines the correct sequence of events to safely and effectively restore circuits. The sequencing is coordinated with the real-time system status from the EMS.

Integration between the OMS and a MWF system allows dispatching of OMS analysis results to field personnel. Field information, such as outage validation, cause, and estimated time to restore, are sent back electronically to the OMS, passing seamlessly to the CIS for call center notification and IVR message updates.

As mentioned previously, the OMS requires an electric connectivity model for its predictive analysis. This connectivity model is generally created and maintained in a GIS. Integrating GIS to the OMS allows this electric connectivity data to regularly pass to the OMS for developing the model that reflects the as-operated configuration of the electric system in the field. The GIS also has the proper tools to manage this data efficiently.

The AMI system, when integrated with OMS, provides for automated reporting of customer outages using the "last gasp" capability of the meters. OMS can automatically determine if a customer's meter matches a specific outage report and then provides a specific outage status. This function can be operative within the utility's IVRU or implemented within the local carrier network for maximum volume.[7]

The AMI system is an effective tool for outage restoration verification where meters are "pinged" (interrogated) to determine their energized state. When well integrated, this provides an automated capability for systematically verifying power restoration at each customer site.

Over time, more advanced features of OMS can be rolled out including the management of planned outages, power flow analysis, advanced predictive analysis and reporting, and gradual migration of existing DMS functionality into OMS.

5.4.1 External Interfaces

With the implementation of a commercial off the shelf OMS, the data links between OMS and other systems (e.g., CLX, EMS/SCADA, AMI, GIS) will be automated. These interfaces include:

[7] KEMA Principals' call center experience

- **IVRU/CLX – OMS**: Trouble calls received by IVRU are directly forwarded to OMS through CLX for processing. Similar trouble calls received by CSRs will be forwarded to OMS. This is real-time interface requiring high performance and guaranteed delivery. The arrival of a trouble call in OMS will trigger a workflow that leads to creation of work order(s) to respond to the outage event.

- **CLX – OMS**: The customer information master data in CLX is brought over to OMS through a batch process to maintain synchronization between the CLX and OMS representations of customers. It is expected that this will be a daily update on an exception basis and full upload of customer data on a weekly basis.

- **OMS – CLX / IVRU**: Updated outage status, estimated service restoration time and other related information are sent from OMS to CLX for communication to customers and maintain a common view on outage status between OMS and CLX. This is real-time interface requiring high performance and guaranteed delivery.

- **GIS – OMS**: Network connectivity data is available to OMS from GIS. The link between GIS and OMS will be a batch interface with daily updates of the network connectivity model from GIS to OMS. OMS users may also red-line or make changes to the network model. The red-lines will need to be pushed back to the GIS support people who will then correct and update the database.

- **EMS/SCADA – OMS**: EMS/SCADA maintains a real-time status of network and substation device data. This data, along with the network connectivity model from GIS is used to support the outage detection and analysis process. A real-time data linkage allows transfer of switch status and outage related information between EMS/SCADA and OMS. Information about the power flows, substation conditions, and change of a controlled switching device is sent from SCADA to OMS. The interface between SCADA and OMS is typically implemented using a standard ICCP link.

- **OMS – Mobile System:** Linkage between OMS and MWF makes it possible to send and receive outage and restoration related information to the field crew, and to process outage restoration and repair orders for scheduling and dispatch. This will be a real-time interface.

- **AMI/MDW – OMS**: The interface between OMS and the AMI/MDW system is used basically for two purposes. First, to receive the "last gasp" signal from the meters and to receive data from pole-top devices indicating a loss of service at the meter or at the pole. Correlating this information with the location of these meters will paint a picture of the areas with no service. The second purpose is for verification of power restoration by pinging meters and pole-tops for power operation verification. This will be a real-time interface.

- **OMS – SAP Work Management:** This interface provides for creating work orders in SAP WMS for support of trouble call management and restoration processes.

5.4.2 OMS System Requirements

As a mission critical system, the OMS will be configured for high performance and high availability. Furthermore, strict access control policies will be enforced for user access to OMS and its data. It is expected that the OMS will be deployed within the PSE Control Center environment and separated from the corporate network by a firewall.

There will be separate OMS hardware environments for: 1) development – needed for staging software releases and version control, 2) testing and training of new releases, and 3) production operation. Furthermore, the production environment will have automatic fail-over capability similar to that for other applications that are deployed in the PSE Control Center. Production OMS will have redundant hardware for servers, database, and network communication.

5.5 The Geographical Information System (GIS)

In the broadest sense, GIS is a collection of computer software, hardware, and data used for the capturing, managing, analyzing, and displaying of geographically referenced information. GIS for an energy utility provides the functionality and applications to manage and use spatially referenced facility data in a graphic format. The GIS implemented in an energy utility contains two major sets of data, land base and facilities. The land-base set includes features of interest to the utility, such as streets, land parcels, and natural areas like rivers and bodies of water. The utility may also include in the land base specific operating features, such as rights of ways and easements, tax and franchise boundaries, environmentally sensitive areas, and physical access information to facilities. The facilities data describes equipment and facility attributes such as connection points, pipe material or age of transformer. Some of the typical attributes stored in GIS include network connectivity model, conductor length and material type by segment, duct and conduit layouts, structure locations, vegetation management planning of corridors, etc.

Currently, PSE distribution data is stored in raster format as part of Maps and Records drawings. Raster data cannot be managed practically because it cannot be easily searched, edited, or analyzed. Raster data can be viewed but is trapped on the map, indistinguishable and inaccessible to the computer as individual features. Analyzing raster data requires visually inspecting each scanned map, line by line, to identify and assess individual features. The process is time consuming and costly.

GIS data is represented as database entries and vector data. It is a highly efficient data format that will not only vastly improve current business processes, such as searching for isolated facilities. It allows storing the distribution system connectivity model and related information in a centralized database, mapped to a single land base, and linked to existing corporate information systems.

The minimum requirements that the GIS must have to support an OMS is the electric network connectivity that includes all conductors, phases, all switching devices, phasing for devices, power injection feed points, and substations. Also, land-base information such as street names, county boundaries, natural features (lakes, streams, etc.), operating division boundaries and other information that will help field personnel in routing and locating facilities are highly desirable.

The accuracy of circuits, connectivity, phasing and operating devices in the system defined in the GIS will affect the accuracy and precision of the OMS outage analysis function. Better data means better analysis results.

With a base GIS implemented to support an OMS, the foundation will be established to support additional functionality, applications and interface to other systems beyond outage. Once PSE electric facilities and land information have been entered into a GIS, this information can be used for a number of applications including on-demand web query, view and print of maps, providing map information to the field using mobile mapping, and analysis of existing facilities, for example, type and size of conductor for a given span. The data in a GIS can also be used to support the planning and design of new facilities, or the refurbishment of existing facilities, for inspection and maintenance planning, and asset management. The electric facility information in the GIS is also useful to support applications like SynerGEE for network analysis.

The GIS deployment can be divided into the following implementation phases:

Phase I: The base GIS capabilities including:

- Commercial GIS software package and supporting hardware platform
- Land-base model and associated data covering the PSE service territory
- Electric transmission and distribution network connectivity model, data conversion and quality control
- Interface with the OMS package

Phase II: Incremental GIS capabilities:

- Electric transmission and distribution assets and facility attributes and supporting data
- Additional supporting maps, images and data in support of vegetation and rights of way management
- Gas transmission and distribution network and equipment modeling, data conversion and quality control
- Integration with SAP for coordination of asset data between GIS and SAP asset management functions

- Graphic Design Tool applications and support

The implementation of Phase I GIS will be coordinated with the Phase I OMS rollout scheduled for 2009.

5.5.1 GIS External Systems Interfaces

The data links between GIS and other systems include:

- **SynerGEE – GIS:** The GIS network model will be initially populated with information that is transferred from SynerGEE. Once the model is fully built in GIS, the GIS will be used as the authoritative source for network model and all changes in the network will be recorded and maintained in GIS. Thereafter, SynerGEE and other applications will retrieve network model and data directly from GIS. This will be file based batch interface.
- **GIS – OMS:** Network connectivity data is provided to OMS directly from GIS. This will be a batch interface.
- **GIS – Mobile:** Mobile map views for the field crew will be supported by GIS.
- **CLX – GIS:** Customer location information in GIS will be provided from, and synchronized with CLX. CLX currently has latitude/longitude coordinate information supplied from the CellNet metering and MDW system. This data and customer information will be synchronized with the GIS land-base and parcel data. Customer connectivity to the distribution network will also be established. For the purpose of outage management, this will allow to associate customers to lateral circuits and feeder(s) so that trouble calls can be immediately traced back to feeder locations.
- **Graphic Design Tool – Planning:** Planning will have access to a Graphical Design Tool that is directly linked to the GIS system.
- **GIS – Electronic Map Board:** Operations will have access to an electronic map board that is supported by GIS. Once the network model is built and populated in GIS, the operators will be able to view the network, including full network connectivity information on GIS screens displayed on large electronic map board. The operators can do trace down and trace up to view details of the network and to see up to date information regarding the status of network switches and devices. Various overlays with dynamic data from OMS and/or SCADA will provide status information.

5.5.2 GIS System Requirements

As an enterprise application, GIS is typically accessed by many concurrent users and therefore GIS application servers, database servers, file servers, and network bandwidth should be configured to be scalable to meet the performance requirements with respect to the number of users, peak user workflow, and user locations. The GIS database servers need to be properly configured to support the various applications, including electric and gas data models. Capacity sizing and design of the GIS servers, databases, and network will be based on a review of usage scenarios.

There will be separate GIS hardware environments for development and testing, and for production operation. The production environment need not be configured with redundant hardware.

5.6 System Integration

Figure 5-3 is a conceptual illustration of the recommended applications and their key interfaces with the existing systems at PSE. New applications are show in yellow in the figure.

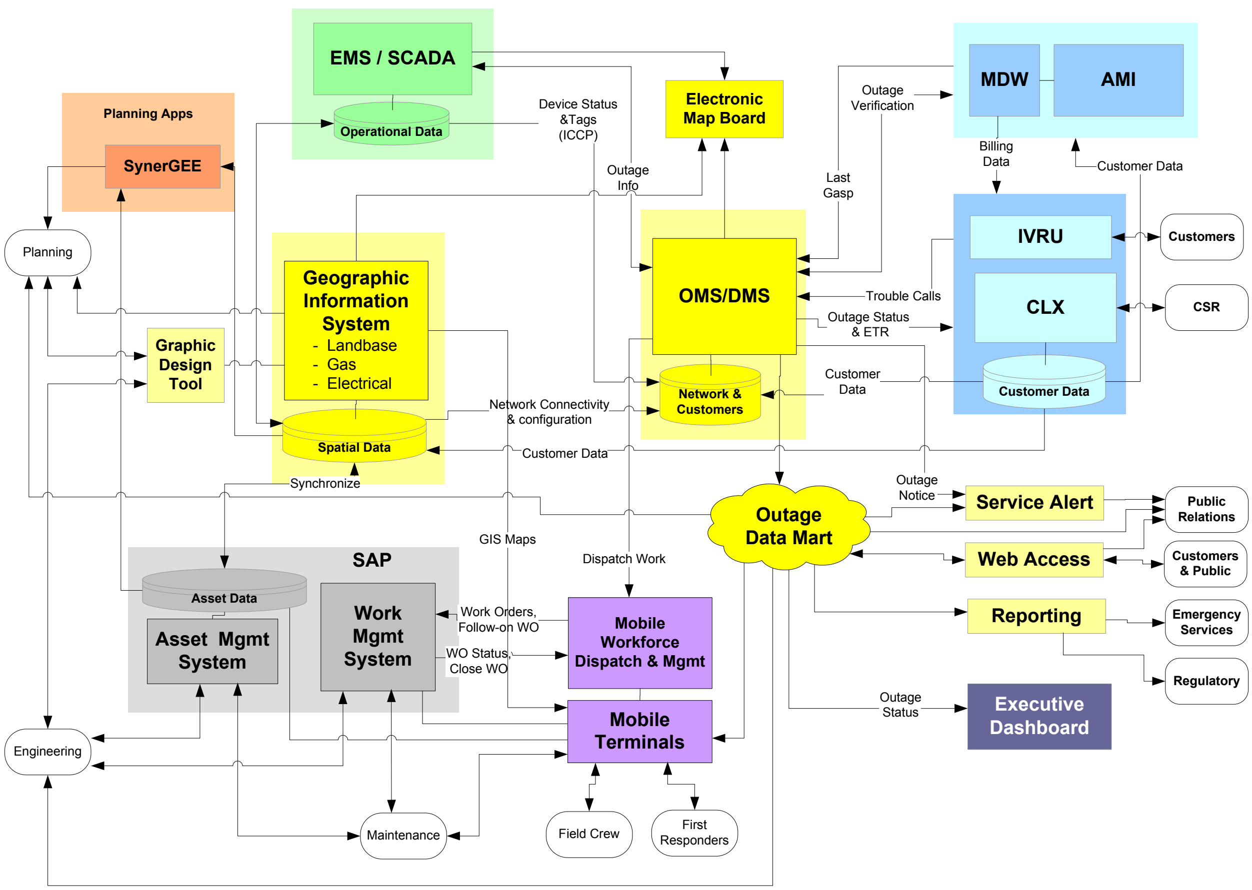

Figure 5-3 Information Flow of Recommended Applications

5.7 Systems Integration Considerations

As can be seen in Figure 5-3, the OMS and GIS will have considerable interaction with other applications and systems. Table 5-2 below illustrates the interaction between data providers and data consumers in an integrated operational environment.

Table 5-2 Data Providers & Consumers

DATA PROVIDER	DATA CONSUMER											
	CLX	IVRU	Mapboard	EMS/ SCADA	SynerGEE	AMI / MDW	OMS / ODM	GIS	Design Tool	Asset Mgmt	Work Mgmt	Mobile
CLX		√				√	√	√				√
IVRU	√						√					
Mapboard												
EMS /SCADA			√				√	√				√
SynerGEE								√	√	√		
AMI / MDW	√		√				√					
OMS / ODM	√	√	√	√		√					√	√
GIS			√		√		√		√	√	√	√
Design Tool					√					√	√	
Asset Mgmt					√			√			√	√
Work Mgmt							√	√				
Mobile	√						√			√	√	

The data exchange and integration between these applications can be grouped into the following categories:

- Real-time data exchange with guaranteed delivery;
- Batch interfaces involving transfer of files or a collection of transactions; and,
- Specialized interfaces specific to a given application environment and/or established industry/application standard;

The preferred approach of integration between OMS, GIS and other PSE systems is illustrated in Figure 5-4. PSE's preferred method for real-time interfaces is through use of Web Services. Web Services provide the flexibility and performance needed for data interfaces between heterogeneous systems, e.g., CLX, Mobile and the OMS. Web Services follow industry standards, e.g., XML and thus provide an application independent method for data integration. It allows interfaces more systems and applications in the future and expands the integration footprint without incurring the cost of redoing the work that is currently planned for OMS. Exceptions to the Web Services approach will be considered only when established data exchange protocols already exist, e.g., the use of ICCP for data exchange with EMS/SCADA, or when the requirements dictate a different approach, e.g., periodic batch file transfer of bulk customer data from CLX to OMS or GIS.

Conceptually speaking, there are three integration buses in the system. The main integration bus uses Web Services and BizTalk as the backbone for access to application data and services. Web Services provides for data and message payload package while the BizTalk backbone provides for data exchange and delivery guarantee. The OMS, CLX, and Mobile for example are integrated via this bus. The second integration bus is for bulk data exchange between GIS, CLX, MDW, OMS and perhaps other applications. This typically involves periodic batch transfer of large amount of file-based information, e.g., network connectivity, customer information, etc. The third integration bus is for exchange of information with applications within SAP (i.e., the Asset Management and Work Management modules) that use SAP's NetWeaver/XI integration infrastructure. Outside of these three integration hubs there are a number of applications that are integrated by other means. They include, for example, an OMS interface with SCADA/EMS which uses the ICCP protocol for data exchange.

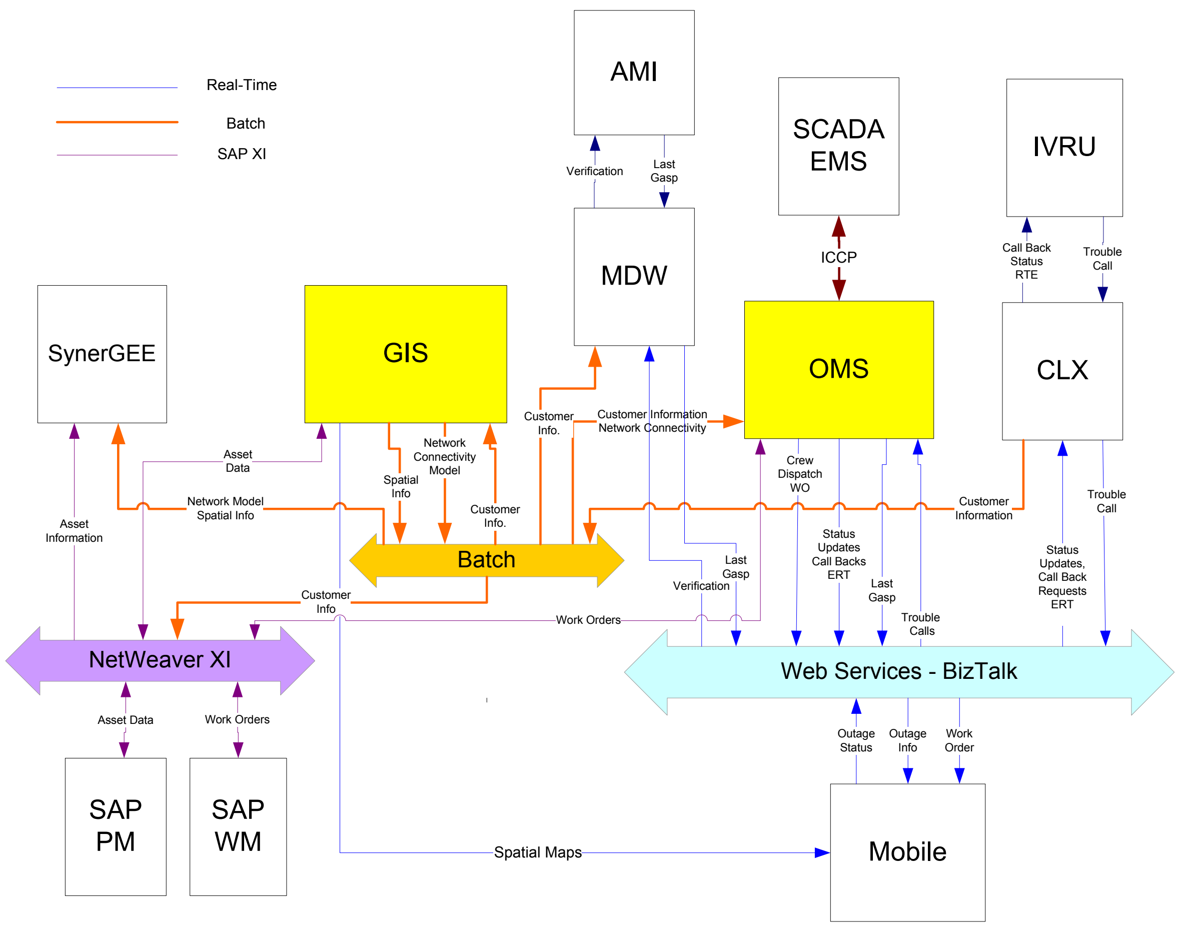

Figure 5-4 Data Integration Methods

6. Implementation Roadmap

The implementation roadmap defines how to get from the current state to the future recommended state. It identifies required project activities, activity durations, and activity interdependencies. Establishment of a detailed roadmap is a critical step in planning the project and assessing the project costs. It is also important in its use to identify and minimize potential schedule and deployment risks through assessment of activity interdependencies and prerequisites.

The recommended roadmap calls for a multi-phase implementation of the OMS and GIS based on the following assumptions:

- PSE can find and select a commercial off the shelf OMS product that is highly configurable requiring a minimum of customization;
- The project will be implemented on multiple tracks with three consecutive business deliverables that are timed to be available prior to the start of the storm season over the next three years (2008-2011);
- Internal PSE resources will be made available on a priority basis to staff this project;
- A change management plan will be developed and executed to realign business processes with the new system. The emphasis is on automating manual procedures that currently cause delays, inefficiencies, and inconsistencies in the outage management and response process;
- End users will be trained to utilize the vendor's product capabilities in the context of reengineered business processes;
- The network connectivity model in GIS will be initially populated with data from existing PSE facility maps to expedite the data gathering effort. GPS will be used primarily for future data location enhancement, not during the initial data conversion and integration phase;
- A single corporate land base will be acquired or created for the GIS. A 2-ft accuracy is anticipated for land base and facility data;
- Facility data will be reviewed and validated during conversion;
- With regard to establishing authoritative sources for information, CLX will continue to be the master data source for customer data, SAP will be the master data source for equipment asset data, and GIS will be the master data soured for all location related information;
- ROW/Easements should be converted, depending on available resources;

- An ongoing in-house GIS maintenance and change management organization will be created and supported during and after GIS integration; and,

- Detailed documentation of all mapping and distribution analysis procedures will be created, updated, and maintained during and after GIS integration.

6.1 Project Schedule

Figure 6-1, below, illustrates the multi-phase, multi-track OMS-GIS project implementation timeline. Broadly speaking, there are three project tracks corresponding to the OMS, GIS, and Integration activities, respectively. The project milestones and business deliverables are synchronized with annual storm seasons in order to realize short term benefits of this investment and at the same time provide increasingly more advanced functionality as time progresses.

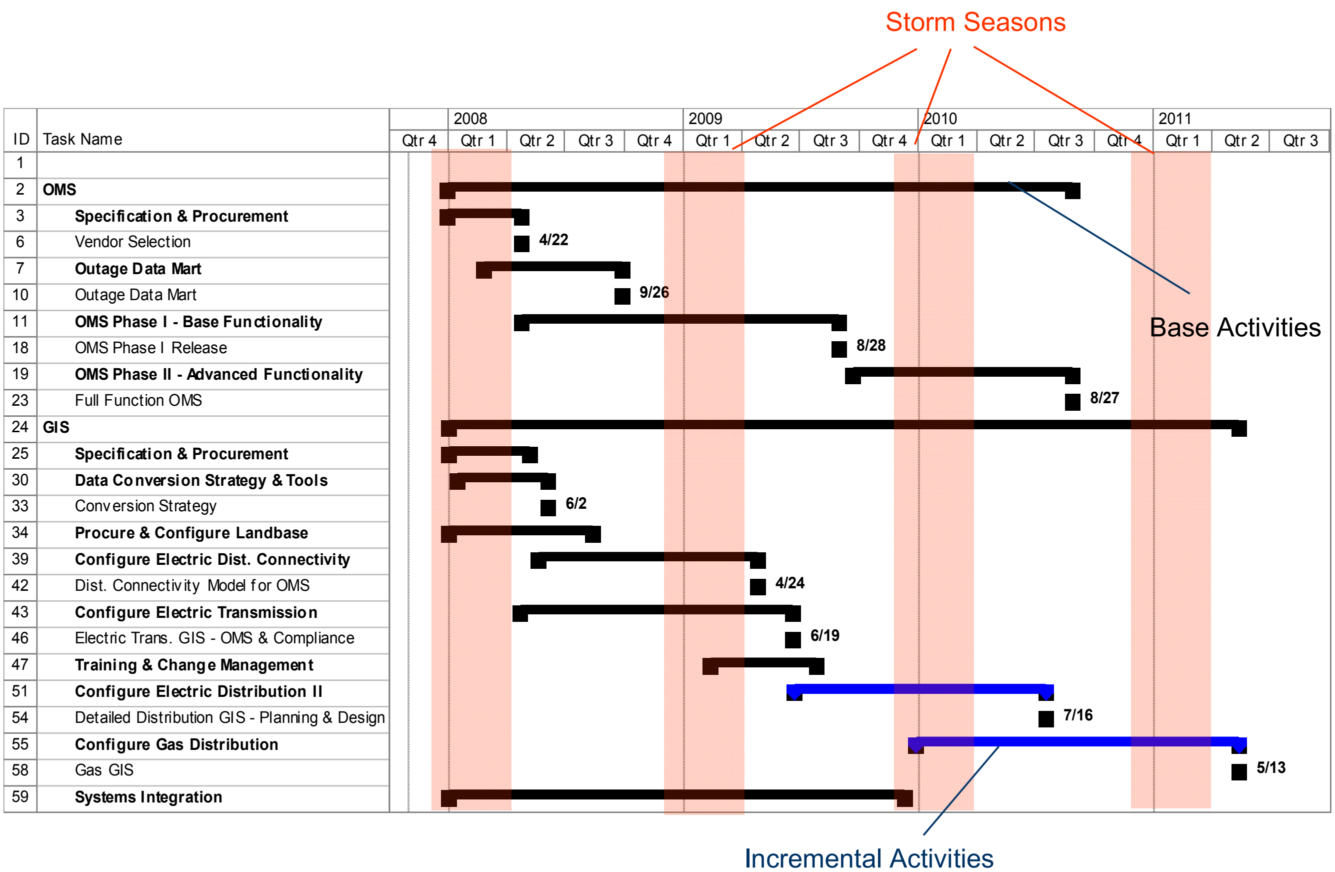

Figure 6-1 OMS/GIS Deployment Plan

Beyond these three major deliverables, there are a number of incremental activities that will be prioritized for implementation in the future. These include further conversion of distribution data to GIS format, configuration of gas distribution data in GIS, and use of GIS for advanced distribution planning and design.

6.2 OMS Roadmap

Figure 6-2 illustrates the activities in the OMS track and the interdependencies between these tasks and those in the GIS and Integration tracks. There are three major milestones in the OMS roadmap which correspond to the delivery of the Outage Data Mart, the Base OMS, and the Advanced OMS from 2008 – 2010.

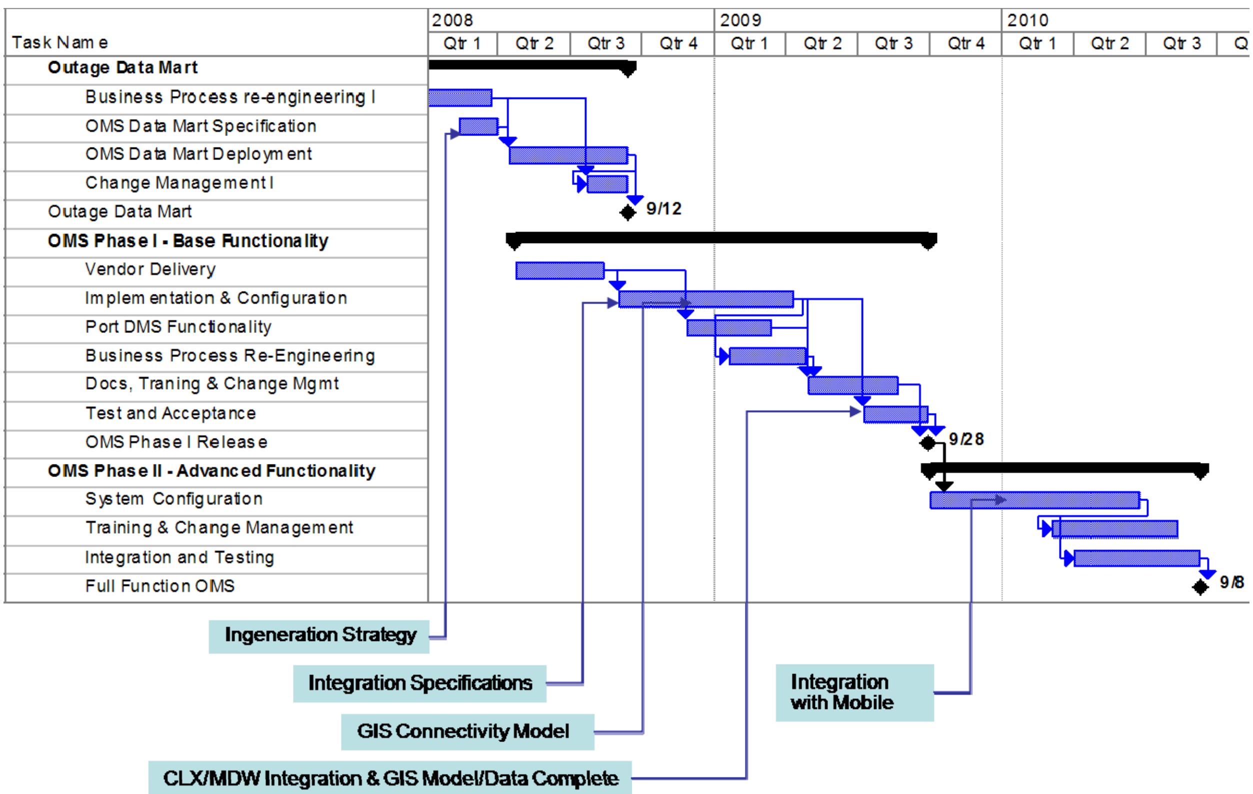

Figure 6-2 OMS Deployment Roadmap

The specific activities on the OMS roadmap are:

- **Business Process Reengineering** – initial review and definition of the future outage management processes. This will serve as the basis for the OMS requirements definition and selection of the appropriate OMS package.

- **ODM Specification** – activities focused on collecting, documenting, and prioritizing the functional requirements for the ODM system.

- **OMS Specification** – activities focused on collecting, documenting, and prioritizing the functional requirements for the OMS system.

- **ODM System Deployment** – activities that culminate in the deployment of the ODM system prior to the start of the 2008 storm season. These include design and development of system interfaces, definition of a normalized data model for the data mart, implementation of the required reporting and presentation forms, testing, and rollout of the ODM system.

- **Change Management** – activities that prepare the organization for utilizing the capabilities of the ODM/OMS/GIS systems including, training, definition of job responsibilities, training, documentation, etc.

- **Vendor Delivery** – vendor selection, product procurement, and delivery of the selected OMS package.

- **Implementation & Configuration** – configuration of the PMS software per PSE's requirements.

- **Port DMS Functionality** – porting of the existing DMS functionality to OMS.

- **Business Process Reengineering** – redefinition of the organizational and job responsibilities, taking advantage of the capabilities provided by the OMS package to automate existing manual processes to achieve greater operational efficiency.

- **Documentation & Training** – preparing the personnel to utilize the new systems.

- **Testing, Acceptance, & Rollout** – testing and rollout of the new OMS.

6.3 GIS Roadmap

Figure 6-3 illustrates the activities in the GIS track and the interdependencies between these tasks with the OMS and Integration tracks.

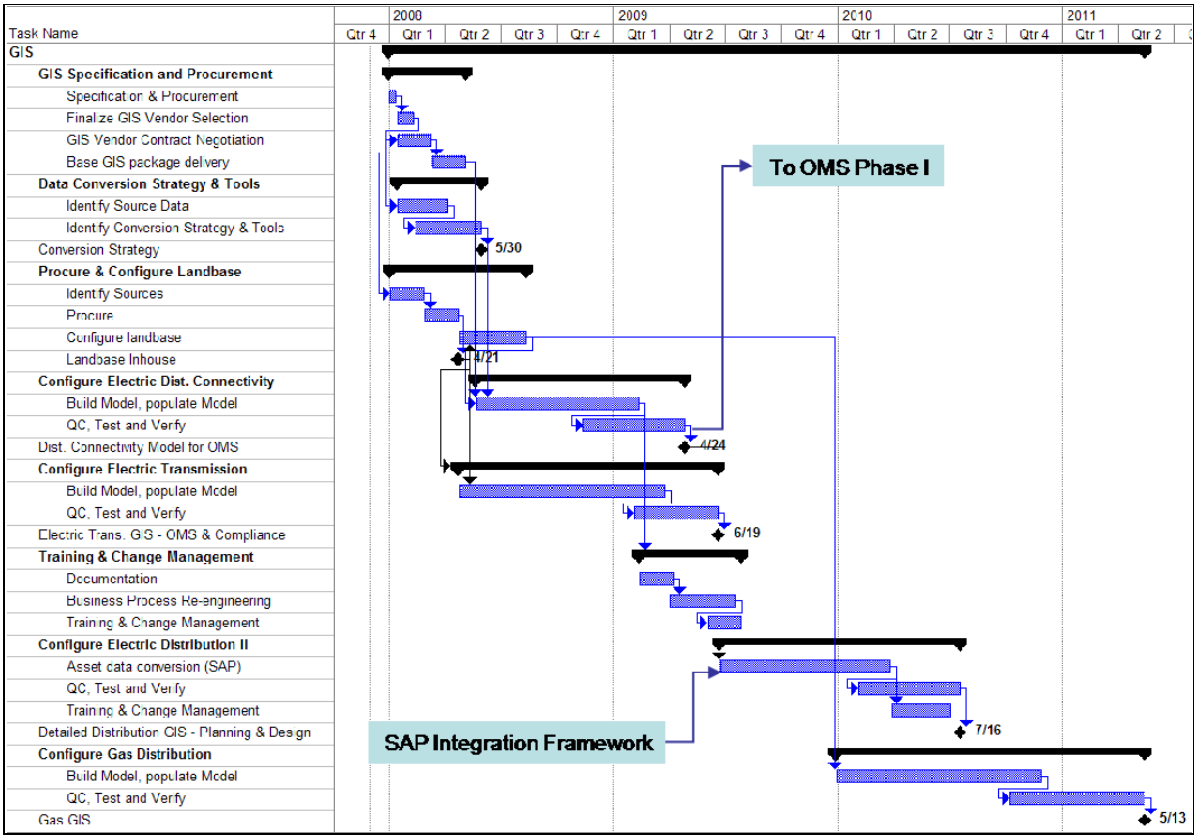

Figure 6-3 GIS Deployment Roadmap

The specific activities on the GIS roadmap are:

- **GIS Specification** – activities focused on collecting, documenting, and prioritizing the functional requirements of the GIS system.
- **GIS Procurement & Delivery** – finalizing GIS vendor selection, product selection and procurement, and delivery of the Base GIS package.
- **Data Conversion Strategy & Tools** – identification of all source data systems for GIS, e.g. maps & records, SynerGEE, etc., developing a strategy for data conversion with respect to content and volume of data that will be converted over the lifespan of this project. Selection of data conversion vendor and data integrity tools.
- **Procurement & Configuration of the Land-Base** – identify potential source, evaluate the best option for land base procurement and deployment.

- **Configure Electric Distribution Connectivity (Part I)** – build and populate the network model from existing data sources. Utilize the network model offered by the GIS vendor to the extent possible. Populate the network data with information from SynerGEE application, to the extent possible. These efforts will help minimize the duration of this critical activity. Perform quality control and testing to verify the accuracy and completeness of GIS data.

- **Training & Change Management** – perform the necessary staff training for effective utilization of the GIS capabilities. Introduce the necessary changes in business processes and job responsibilities for greater operational efficiencies.

- **Configure Electric Distribution (Part II)** – extend the data in GIS to include distribution equipment asset data from SAP.

- **Configure Gas Distribution** – extend the data models in GIS to include Gas Distribution network data.

6.4 Integration Roadmap

The integration roadmap closely parallels the deployment of the OMS and GIS systems. The following Figure 6-4 illustrates the GIS roadmap activities and the interdependencies between these and the other two tracks.

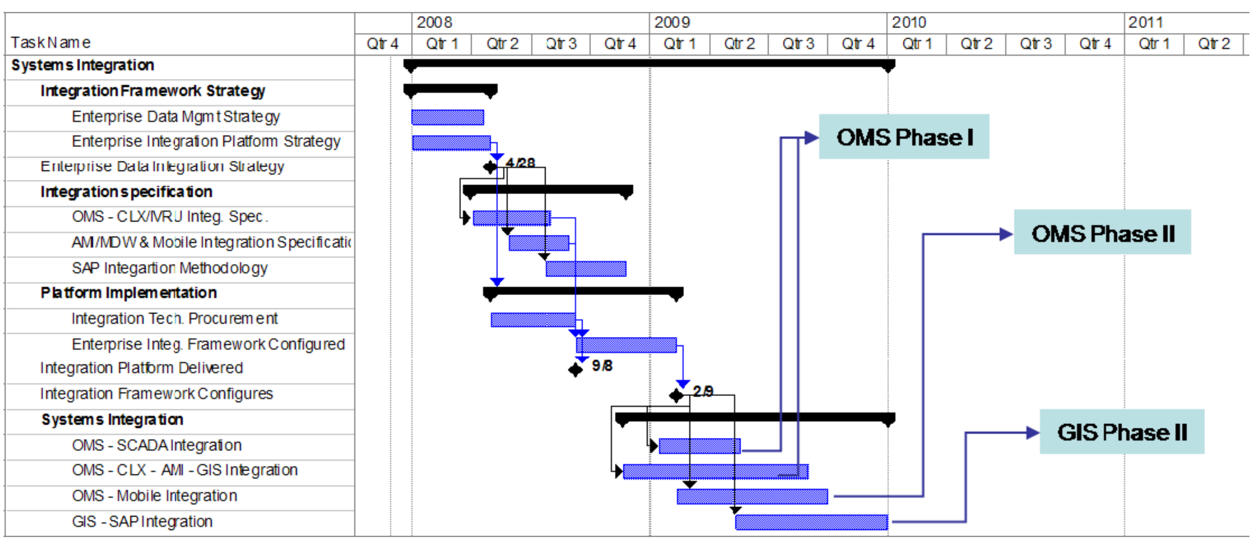

Figure 6-4 Integration Roadmap

The specific activities on the Integration roadmap are:

- **Integration Framework Strategy** – developing the PSE operational data management strategy, developing an integration platform strategy.

- **Integration Requirements Specification** – collecting, documenting, and prioritizing system and data integration requirements between participating systems. This includes specifics of data exchange content, frequency, volume, security, data management, and service level agreements. The participating systems are: OMS, GIS, CLX/IVRU, MWF, AMR/MDW, EMS/SCADA, Mobile, and SAP.

- **Platform Implementation** – develop technical requirements for integration including hardware, software, network communication and security, middleware and messaging, and other infrastructure to support web services deployment.

- **Platform Delivery & Configuration** – install and configure the servers, databases, and network communication.

- **System Integration** – develop, test and roll out data exchange capabilities between OMS – SCADA, OMS – CLX – AMI, OMS – Mobile, and GIS – SAP.

7. Cost Assessment

This section provides cost estimates, both capital and O&M, for the proposed program. A separate cost breakdown is provided for the OMS and for the GIS applications. The cost estimates reflect the scope of the envisioned functionality and are based on industry experience and norms for implementation of these capabilities at utilities with a similar size using Commercial-off-the-Shelf (COTS) products including the required support services. These services include technical specification, business process engineering, procurement, configuration, possible customization, implementation, integration, roll-out, training, and change management activities.

Costs are calculated over the 15-year project lifespan from 2008 to 2022. The labor component accounts for internal PSE resources and external vendor/consultant staff, as needed. The estimates cover costs associated with the following resources and material.

- PSE resource costs
- Hardware costs and COTS and 3rd party software licenses
- COST vendor support for product configuration and implementation
- Outside professional and technical services
- O&M costs

The cost estimates also reflect the project implementation timeline considering task interdependencies, resource cost categories, and the mix of internal and external resources utilization.

7.1 Assumptions

Costs are estimated per major task activity and based on estimated efforts by labor category. Table 7-1 presents labor cost assumptions used in costing the project efforts.

Table 7-1 Labor Cost Assumptions

Category	Rate		Category	Rate	
Labor Costs					
PSE Management	[redacted]	$/hr	OMS Vendor	[redacted]	$/hr
PSE Operations		$/hr	GIS Vendor		$/hr
PSE Mapping & GIS		$/hr	Integration Vendor		$/hr
PSE IT		$/hr	Consultant		$/hr
Service Provider		$/hr	GIS Conversion Vendor		$/hr
Cost Escalation Factor	3%	%/year			

Table 7-2 O&M Labor Cost Assumptions

Category	Assumption	Base
Hardware Maintenance Fee	15%	H/W purchase price
Software Maintenance Fee	20%	S/W license price

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7.2 OMS Costs

Key assumptions made in estimating the OMS implementation costs include:

- PSE will procure and implement a standard vendor OMS package through a competitive process. A list of potential candidate vendors includes Oracle Utilities/SPL, CGI, GE Energy, ABB, Intergraph, Telvant Miner & Miner, AREVA and possibly others.
- It is assumed that the OMS package is procured based on a one-time perpetual license price of [redacted] This license price is inclusive of any required third party software, e.g., database management, communications, security, etc.
- Hardware costs for the OMS system including servers and workstations is estimated at [redacted]
- Map-board, or alternatively, personalized multi-screen display, for support of large screen projection and spatial display of outage data is estimated at [redacted] The price range for such technologies could vary considerably with the size, type and the number of the large screens deployed. The budget here is a placeholder.

Figure 7-1 An Example of Multi-Screen Personalized Map Board

The OMS costs are summarized in Table 7-3. The Outage Data Mart cost includes the design and implementation costs only. The specification costs, as well as business process re-engineering, training and change management costs, are covered in the respective line items. The OMS implementation costs are inclusive of the vendor package configuration and acceptance testing. It should be pointed out that the estimates here are based on industry averages and not reflect a particular vendor quotation.

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Table 7-3 OMS Cost Estimates ($000)

	Total	2008	2009	2010	2011
Specification & Procurement	[redacted]				
Outage Data Mart Implementation	[redacted]				
Phase I OMS Implementaion	[redacted]				
Integration with CLX, GIS, EMS, MDW & Mobil	[redacted]				
Phase II OMS Implementation	[redacted]				
Training & Change Management	[redacted]				
Software License	[redacted]				
Server Hardware	[redacted]				
Electronic Mapboard	[redacted]				
Total Capital	[redacted]				

7.2.1 OMS O&M Costs

The annual O&M costs associated with OMS software and hardware maintenance, as well as applications support is summarized in the following Table 7-4. It is assumed that the OMS package will require 0.5 FTE for on-going support.

Table 7-4 Outage Management System O&M Cost Estimates

	Rate	First Year Cost ($000)
Hardware Maintenance	15%	[redacted]
COTS Software Maintenance	20%	[redacted]
Support Services	0.5 FTE	[redacted]
Total Annual O&M Cost		[redacted]

7.2.2 Breakdown of Labor Efforts

It is estimated that the OMS implementation at PSE will require approximately 24,600 hours of professional services divided between PSE resources, OMS vendor, integration vendor and consultant services. Table 7-5 provides a breakdown of this effort by key task activities as well as internal PSE and external vendor/contractor efforts.

Figure 7-2 graphically shows the OMS implementation resource requirements by labor category.

OMS Hours	Total Hours	Internal PSE	Outside Services
Full OMS Package	**35,794**	**15,282**	**20,512**
Specification & Procurement	**1,196**	**416**	**780**
Detailed Requirements Spec & Vendor RFP	**572**	112	460
Proposals and Evaluation	**624**	304	320
Outage Data Mart	**3,871**	**1,923**	**1,948**
OMS Data Mart Specification	**480**	200	280
Business Process Re-Engineering (ODM)	**1,280**	480	800
OMS Data Mart Deployment	**1,591**	883	708
Change Management (ODM)	**520**	360	160
OMS Phase I - Base Functionality	**11,160**	**4,480**	**6,680**
Vendor Delivery	**912**	272	640
Implementation & Configuration	**3,220**	1,220	2,000
Port DMS Functionality	**2,500**	1,100	1,400
Business Process Re-Engineering - Phase I	**1,280**	560	720
Change Management (Phase I)	**728**	408	320
Test and Acceptance	**2,520**	920	1600
OMS Phase II - Advanced Functionality	**8,376**	**3,200**	**5,176**
System Configuration	**5,208**	1,640	3568
Training & Change Management (Phase II)	**1,160**	680	480
Integration and Testing	**2,008**	880	1128
Systems Integration	**11,190**	**5,262**	**5,928**
OMS - SCADA Integration	**1,509**	743	766
OMS - CLX - AMI - GIS Integration	**6,704**	3,274	3,430
OMS - Mobile Integration	**2,978**	1,246	1,732

Table 7-5 Labor Effort Estimates for OMS Package

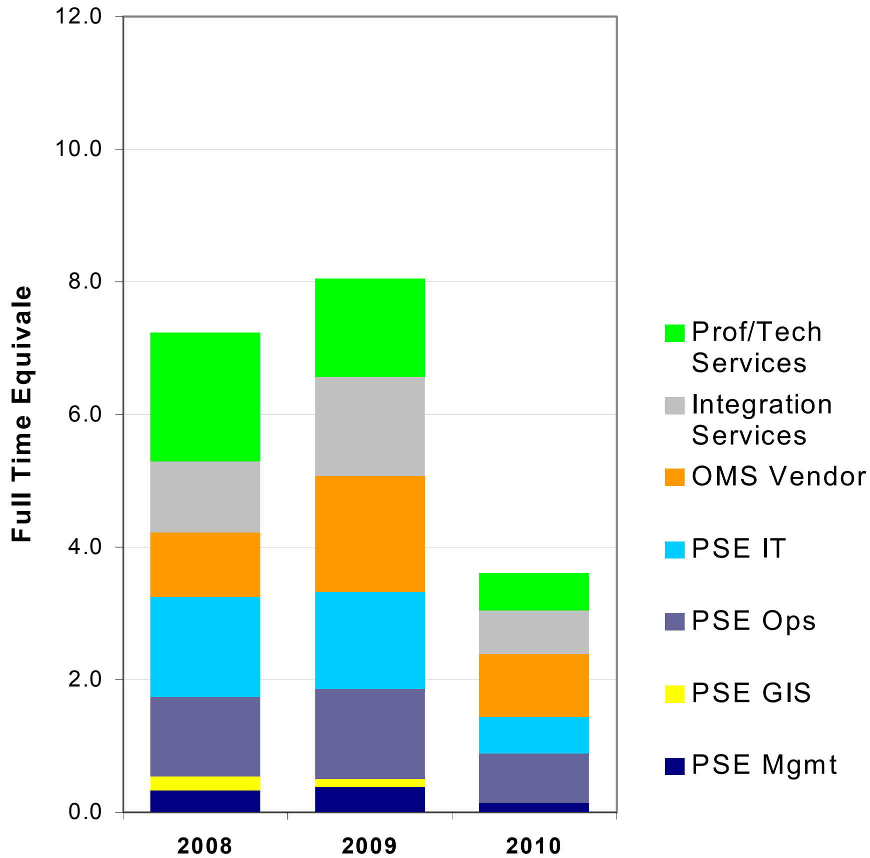

Figure 7-2 OMS Implementation Breakdown by Labor Category

The following subsections provide a narrative discussion of these hours by key project activities.

7.2.2.1 Specification and Procurement

This effort involves development of functional specifications and technical inputs for an RFP document for procurement of the OMS technology. Also included in this effort is the support for vendor proposal evaluation process. This effort is estimated at about 1200 hours with activities divided at 1/3 for PSE and 2/3 for outside services.

7.2.2.2 Outage Data Mart Implementation

This effort involves the specification and deployment of the ODM in 2008. The effort is slightly more than a man-year of effort divided almost equally between PSE and outside resources. The implementation of the ODM also involves certain changes to outage related business processes and training and change management associated with the process changes. The efforts associated with the business process and change management are reported later in this section.

7.2.2.3 Outage Management System – Base Functionality

It is estimated that the Phase I of OMS implementation scheduled for 2009 will require approximately 9,100 of work with 60% of the work carried out by outside services including the OMS vendor, integration vendor and outside professional services/consultant. This effort includes delivery, installation and configuration of the base OMS package, migration of the existing DMS functionality, and testing and acceptance of the base package. Activities associated with the integration of OMS with CLX, EMS and GIS are presented below. Also presented below is training, business process reengineering and change management activities associated with this release.

7.2.2.4 OMS Integration

The OMS package requires data integration with several external systems including SCADA/EMS, CLX, AMI (MDW), GIS and mobile. An approximate 11,200 hours has been estimated for this work, almost equally divided between PSE IT and outside resources that include the OMS vendor, integration partner, and other professional services.

7.2.2.5 Phase Three Outage Management System

In Phase Three, implementation of OMS advance functionality is scheduled for 2010 and involves implementation of advanced functionality including integration with mobile workforce management (MWF), planned switching, power flow analysis, and fine tuning of base applications. This effort is estimated at 7,200 hours with 2/3 of the work performed by outside resources including the OMS vendor, integration partner and outside professional services.

7.2.2.6 Business Process Re-Engineering

The new functionality and capabilities of the OMS will require changes in the existing outage management and restoration business processes. The purpose for this process re-engineering effort is to ensure that the new technologies are properly integrated into business processes, and that these business processes takes full advantage of each technology's capabilities. KEMA has estimated approximately 5,000 hours of effort in support of process re-engineering and the associated change management activities. This effort is equally divided between PSE and outside resources. The PSE involvement includes training hours for the operations and customer service personnel. Three stages of training/change management are planned for, including training associated with Data Mart functionality, training for Phase I OMS release, and training for Phase II OMS release.

Without business process re-engineering the full potential of OMS and GIS will not be realized. The necessary business process changes will address issues that were identified in the 2006 storm assessment report, including, providing higher quality data and more up to date outage and restoration information to customers, the Customer Service Center, and to key PSE management.

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7.3 GIS Costs

The GIS implementation cost estimates are provided for the GIS base project necessary to meet the OMS implementation requirements and for GIS incremental activities. The base project includes the selection and implementation of the GIS software, installation and configuration of land-base models to cover the PSE service territories, and to configure electric distribution and transmission connectivity and the basic spatial information needed for support of outage management process. The incremental project builds upon the base capabilities and includes the additional models and functionality needed to support electric operations planning and engineering, vegetation management and other standard electric mapping and records functions, as well as implementing and configuring the gas transmission and distribution models/data.

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7.3.1 GIS Capital Costs

Table 7-6 provides a summary of the GIS project costs. The project is expected to last for four years with the technology procurement and the base system implementation taking place in 2008. The GIS data modeling, configuration and conversion activities will begin in 2008 and span through 2011.

	Total	2008	2009	2010	2011
Specification & Procurement					
Software License					
Hardware					
Landbase Model and Configuration					
Base GIS Software Installation					
Electric T&D Conversion Phase I - OMS					
Electric T&D Conversion Phase II					
Gas Conversion					
SAP Integration	$				
Training & Change Management	$				
Total Base Project	$				
Total Incremental Activities	$				
Total Capital	$				

Table 7-6 GIS Implementation Costs for Base and Incremental Projects ($000)

The following assumptions are made in building the GIS cost estimates:

- PSE will establish a functional, performance and technical requirements specification for the GIS package.
- PSE will procure a best-practice commercial GIS software platform. The GIS package will be purchased based on a one-time perpetual license term paid upon the delivery of

the software package. The license price is estimated at [redacted] This license price is inclusive of any required third party software, e.g., database management, communications, security, etc. Candidate suppliers include ESRI, Intergraph and GE.

- Hardware costs for the GIS system including servers and workstations are estimated at [redacted]

- The cost estimate includes a [redacted] ne item for acquisition of the Land-base model base package plus costs for implementation, integration and customization. However, it is possible to obtain the land-base from Counties and regional organizations that maintain local land-base models for municipal and other purposes under a reciprocal collaboration agreement. Table 7-7 provides a list of potential land base sources for PSE served Counties.

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County		Parcel Data Format	RDBMS	Positional Accuracy Estimate	Source
Clallam County		Coverage	SQL	tbd	
Grays Harbor County		SHP	SQL	tbd	
Island County	*	SHP	SQL	tbd	
Jefferson County	*	SHP	SQL	tbd	
King County	*	SDE/Geodatabase	SQL	+/- 1.5' Urban +/- 15' Other	POCA Files, Survey, and Ortho
Kitsap County	*	SDE/Geodatabase	Oracle	+/- .1' Urban +/- 50' Other	Survey Grade Legal Descriptions
Mason County		SHP	SQL	+/- 1' Urban +/- 20' Other	Oregon Map Standards
Pierce County	*	SDE/SHP	SQL	+/- 2.5' Urban +/- 25' Other	Ortho, Legal Descriptions, and Survey
San Juan County		SHP	Oracle	tbd	
Skagit County Geographic Info	*	SDE/Geodatabase	SQL	+/- 1' Urban +/- 200' Other	Quarter Section Match, Survey, and Legal Descriptions
Snohomish County Public Works	*	SDE	SQL	+/- 2' Urban +/- 10' Other	Survey Section & Quarter Section, Ortho, and Legal
Thurston County	*	SDE/Geodatabase	SQL	+/- 2' Urban +/- 100' Other	Plats and Ortho
Whatcom County Engineering	*	Geodatabase/SHP	SQL	+/- 5' Urban +/- 20' Other	

*Puget Sound Energy Territory

Table 7-7 Potential Sources of Land-base Data for PSE Service Territories (Source ESRI Research)

- To the extent possible, the GIS data conversion and configuration will be automated using interface software and tools to map existing PSE sources, e.g., SynerGEE network models and data, SAP asset data, etc. Also lower cost data conversion resources will be utilized in support of the effort and data quality control activities. These tools can be used in the future for synchronization (integration) of the GIS data and other source PSE applications.

- Use industry standard GIS models for electric and gas distribution and transmission equipment and network if all possible.
- The data integration costs associated with OMS is covered under the OMS application. The cost for integration of GIS with SAP is included here with a consideration that the leading GIS vendors have already developed a SAP interface module.

Based on these assumptions, the base cost for the GIS package (electrical connectivity) is estimated at [redacted] nd the incremental cost for Gas and asset modeling is estimated at [redacted]

7.3.2 GIS O&M Costs

The annual O&M costs associated with GIS software, land base and hardware maintenance, as well as applications support, is summarized in Table 7-8.

Table 7-8 Outage Management System GIS Cost Estimates

	Rate	First Year Cost ($000)
Hardware Maintenance	15%	[redacted]
COTS Software Maintenance	20%	[redacted]
Support Services	1 FTE	[redacted]
Total Annual O&M Cost		[redacted]

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7.3.3 Breakdown of Efforts

It is estimated that the full GIS implementation at PSE including both gas and electric will approximately 58,000 hours or 32 person-years of effort, out of which approximately 43,000 hours or 24 person-years are for data conversion, configuration and quality control activities. Table 7-9 provides a breakdown of the key activities by PSE and by external vendor/contractor efforts.

Figure 7-3 provides a graphical presentation of the estimated OMS related labor efforts based on Full Time Equivalent (FTE) for each calendar year and for each key resource category. As can be seen the bulk of effort during the first three years will be by GIS Data Conversion vendor and by PSE GIS resources for data review, interpretation and Q/C.

A narrative discussion of the key GIS project activities is provided in the subsections below.

Table 7-9 Labor Effort Estimate for GIS Application

OMS Hours	Total Hours	Internal PSE	Outside Services
Full GIS Project	**57,886**	**19,106**	**37,340**
GIS Specification and Procurement	**1,440**	**560**	**880**
Specification & Procurement	**344**	104	240
Finalize GIS Vendor Selection	**256**	136	120
GIS Vendor Contract Negotiation	**440**	320	120
Base GIS package delivery	**400**		400
Data Conversion Strategy & Tools	**1,584**	**696**	**888**
Identify Source Data	**768**	448	320
Identify Conversion Strategy & Tools	**816**	248	568
Procure & Configure Landbase	**1,768**	**856**	**912**
Identify Sources	**408**	160	248
Procure	**400**	296	104
Configure landbase	**960**	400	560
Configure Electric Dist. Connectivity	**11,076**	**2,580**	**8,496**
Build Model, populate Model	**7,196**	2,076	5120
QC, Test and Verify	**3,880**	504	3376
Configure Electric Transmission	**7,328**	**3,072**	**4,256**
Build Model, populate Model	**5,528**	2,152	3376
QC, Test and Verify	**1,800**	920	880
Training & Change Management	**2,768**	**1,152**	**1,616**
Documentation	**464**	144	**320**
Business Process Re-engineering	**1,376**	480	896
Training & Change Management	**928**	528	400
Configure Electric Distribution II	**10,024**	**3,688**	**6,336**
Asset data conversion from SAP	**6,488**	2,072	4416
QC, Test and Verify	**2,536**	1,096	**1440**
Training & Change Management	**1,000**	520	480
Configure Gas Distribution	**17,728**	**5,864**	**11,864**
Build Model, populate Model	**12,312**	3,784	8,528
QC, Test and Verify	**5,416**	2,080	3336
Systems Integration	**2,730**	**638**	**2,092**
GIS - SAP Integration	**2,730**	638	2,092

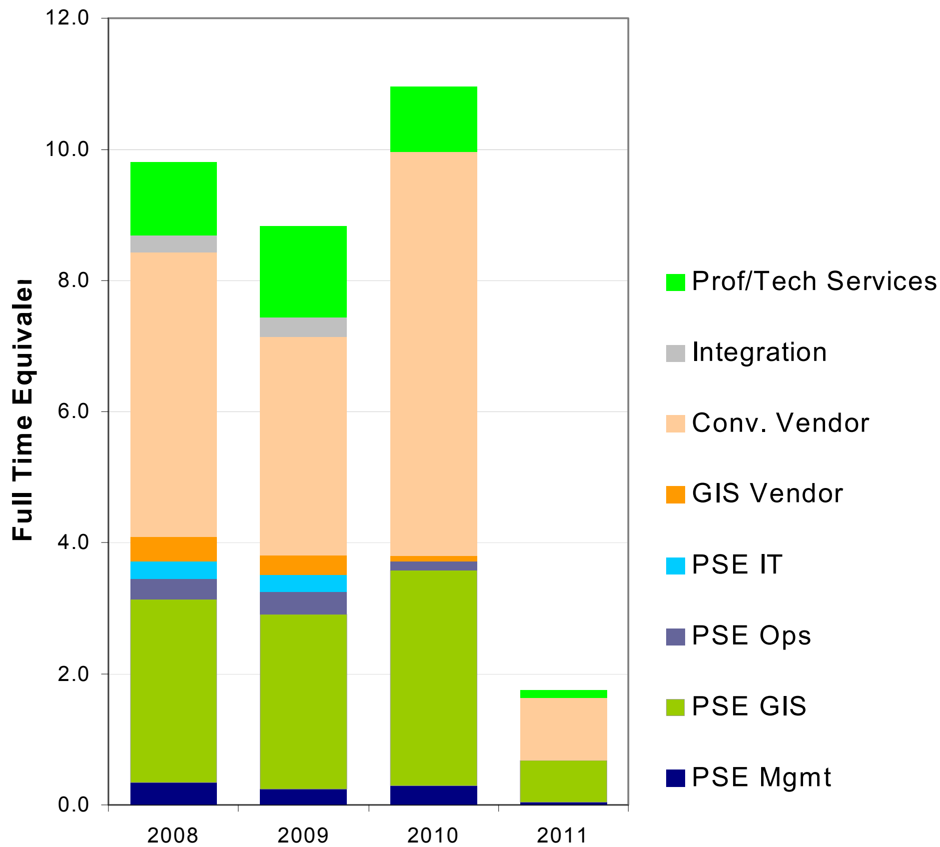

Figure 7-3 GIS Implementation Breakdown by Labor Category

7.3.3.1 Specification and Procurement

This activity includes the development of functional and technical requirements for the GIS package and the GIS procurement specification document. It also includes the GIS software and GIS data conversion and vendor selection and vendor scope of delivery determination and negotiations. The effort also includes delivery of the base GIS software package from the GIS vendor. A total of 1,440 hours are estimated with approximately 2/3 of the work is allocated to outside resources.

- Resource estimates include both the base and the incremental projects
- Data modeling and conversion strategy

7.3.3.2 Data Conversion Strategy & Tools

This activity involves identifying the available source data, establishing data conversion strategy, and developing the necessary in-house tools for support of the data conversion process.

7.3.3.3 Procure and Configure Land-base

Implementation and configuration of the land-base model for the PSE service territory is estimated to require about one-person year of effort involving land-base selection, acquisition, configuration, verification and model integration.

7.3.3.4 Configure Electric Distribution I - Network Connectivity

This activity involves building, integrating and verifying the complete electric distribution network connectivity model including spatial data, down to secondary distribution lines and customers locations. It is expected that SynerGEE planning models will be fully leveraged for this purpose.

7.3.3.5 Configure Electric Transmission

This task involves building, integrating and verifying the GIS electric transmission network model including spatial information for key asset and substation equipment. It is expected that network models used in EMS and transmission planning studies will be leveraged for this purpose. The effort for this task is estimated at about 4 person-years (7,300 hours).

7.3.3.6 Training and Change Management

The introduction of the GIS technology will impact a number of processes and functions in the Maps and Records department, as well as others who use Maps and Records information and raster maps, e.g., planning and engineering functions. A total of 2,800 hours has been allocated to support process redefinition, documentation and training of staff involved.

7.3.3.7 Configure Electric Distribution II – Incremental Activity

As part of this task, the base electric distribution connectivity model developed earlier will be augmented with asset and equipment data to provide a complete GIS representation for the electric distribution system. It is assumed that most of the assets are already modeled in SAP and with development/implementation of an interface module the data in GIS and SAP models will be synchronized, minimizing data conversion costs. Also included here are the quality control, testing, and verification of the covered data.

7.3.3.8 Configure Gas Transmission and Distribution – Incremental Activity

Leveraging the already implemented land-base, customer and utility facility models, under this task the gas pipelines and assets will be mapped into the GIS software. SynerGEE gas models could also be leveraged for this purpose. This task involves asset, facility and connectivity modeling (using standard industry models when possible), data conversion, data configuration, data integration and quality control, and verification activities.

The activities are estimated to require approximately 10 person-years of effort (17,700 hours) with about 70% of the work performed by the Conversion vendor and outside resources.

8. Benefits Assessment

The OMS and supporting GIS provides a wide range of benefits for both PSE and for PSE customers. Key benefits are identified, and to the extent practical, they are quantified in this section.

8.1 Outage Management Benefits

The OMS benefits can be grouped into the following major categories

I. It reduces the response time to outages and it reduces outage duration

II. Improves the quality and timeliness of outage and restoration information provided to our customers and other stakeholders

III. It improves PSE workforce productivity for outage detection, restoration and reporting process.

Outage Management at PSE is currently based on a general set of procedures that use existing systems to capture, organize and communicate information on outage calls, electric first response, damage assessment, service provider crew dispatch, system operations, and restoration efforts. This information is often manually coordinated, and thus is not well scalable during major events. An OMS is one of the foundational technologies for utility operations that bring together trouble calls, customer location and information, network status and connectivity, damage assessment and analysis, crew dispatch and restoration information into one coordinated system.

The following subsections provide some of the operational benefits of OMS.

8.1.1 Systems Operations Benefits – Qualitative Discussion

An integrated OMS provides the following benefits to the System Operations department:

- Improves the effectiveness of personnel in System Operations for outage analysis;
- Ability to dispatch First Responder to exact location of outage cause or to the nearest protective device;
- Ability to know the location of all First Responders and restoration crews in the field;
- Faster and current communications of outage, status and restoration to others within the company and to external entities;
- Faster planned switch order development, with safety documents reference and switch plan library capability;

- Switching steps for clearance automatically recorded as the crew executes the plan in the field for documentation and record keeping;
- Power flow analysis allows load capacity analysis prior to performing the actual switching operation;
- Faster follow-on work orders possible for permanent repairs after restoration;
- Improved field productivity by providing additional outage- and customer-related data in a graphic view;
- Improved tracking and prioritization of critical customers during outage situations (hospitals, customers on life support, etc.);
- Electronically maintain wallboards for consistency and accuracy; and,
- Automatically generate outage reports and statistics.

8.1.2 Customer Service Benefits

Customer Service benefits include the following:

- Ability to communicate the two critical pieces of information that customers without power want to know;
  - "That PSE knows I am out of power"
  - "How long will it take to restore the power"
- Improves the effectiveness of the Customer Call Center personnel;
- Outage status information (e.g., outage extent, estimated time to restoration) is readily provided to the Customer Service Representatives (CSRs) and to IVRU to provide to customers calling in;
- Reduces the number of calls that need to be handled by a CSRs when IVR is regularly updated; and,
- Provides information on the status of the outage and when restoration is completed;

8.1.3 Improved Outage Communications

Communications benefits within PSE include:

- Service Alert type functionality of an OMS allows notifying key personnel within PSE on outage event, status and restoration through a variety of means (cell phone, pager, text message and email);
  - Major Account Representatives
  - Public Affairs
  - Media Relations
  - Executives
  - Key Stakeholders
- Executive Dash Board functionality provides outage event, status and restoration information in a summary format to key PSE personnel.

Communications benefits external to PSE include:

- Ability to inform key PSE personnel who communicate with the media, public service agencies and select organization of the outage status using current and consistent information;
- Ability to provide an outage map with outage information on the PSE web site for view by the public; and,
- Ability to convey outage information quickly to service providers.

8.1.4 Storm Condition Benefits

Storm condition benefits include:

- Faster ability to know the extent of the outage and the ability to correlate damage extent to restoration estimates;
- Internal and external communications of storm outage status, restoration times and restoration status;

- Storm board updated with current information from the OMS. Streamlined communication and coordination between Load Center and storm board operation centers regarding network operational status;
- Web Call Entry capability allows entering trouble calls from customers by an external service bureau, PSE employees other than the Call Center, or employees at home;
- Reduced post-storm auditing and reconciliation for management and regulatory reporting calculations; and,
- Reduced auditing labor.

8.1.5 Other Benefits

Benefits to departments like engineering and planning include:

- Ability to identify problem circuits;
- Outage statistics provide data for reliability analysis, areas for investigation of momentary outages (e.g., vegetation management), and repair or replace decisions;
- Ability to use outage data for planning and refurbishment design of circuits, or relocation of circuits for improved reliability;
- Identify devices or equipment that cause outage events;
- Ensure Regulatory Compliance;
- Provide improved IEEE standard reporting; and,
- Provide audit trails for all data capture instead of only logging.

8.2 Outage Management Benefits – Quantitative Discussion

To quantify the OMS benefits for PSE, KEMA examined the potential impact of a best practice OMS technology on the existing PSE outage management process.

8.2.1 Outage Management Process

The effectiveness of the Outage Management process is typically measured by SAIDI. Table 8-1 presents the recent history of SAIDI and the SAIFI for PSE. As can be seen in the table and in Figure 8-1 the 2006 represented a significant increase against the five year trend both in duration and in frequency of outages.

It should be noted that SAIDI does not include outages due to major events, and as can be seen 2006 also represented significant increase in the major event days.

		2002	2003	2004	2005	2006
SAIDI (Minutes)	PSE SQI Method	105.30	133.39	112.78	128.65	214.45
	IEEE 1366 Method	99.46	106.73	113.75	129.82	162.97
SAIFI	PSE SQI Method	0.83	0.80	0.77	0.94	1.23
	IEEE 1366 Method	0.76	0.71	0.77	0.95	1.03
Major Event Days	PSE SQI Method	4	13	9	7	34
	IEEE 1366 Method	3	9	5	4	24

Table 8-1 PSE Reliability Index History

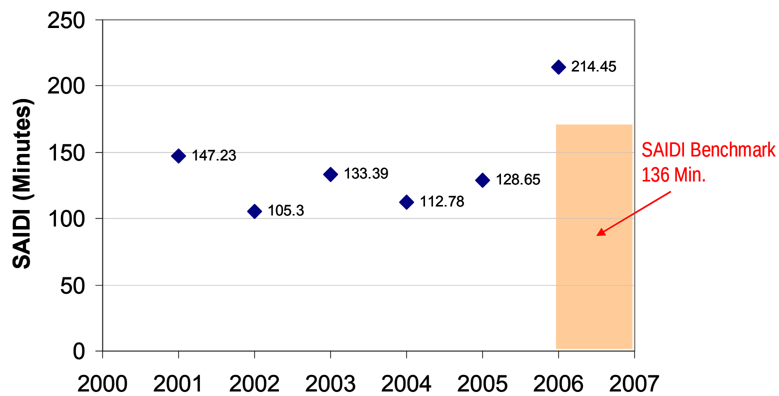

Figure 8-1 SAIDI Trend for PSE

The current SAIDI benchmark target for PSE is at 136 minutes. The 136 minutes of SAIDI represents the aggregate time duration of the various steps involved in the outage restoration process. Typically, the outage management process involves involve the following steps:

- Outage detection;
- Damage assessment;
- Restoration and switching plan;
- Crew dispatch;
- Repair and Outage restoration; and,
- Restoration verification.

These steps are generally followed for both smaller outages caused by equipment failure, accidents and other causes, and for major storm events that require substantial resource mobilization, crew dispatch and an involved repair and restoration process.

By collecting, coordinating and analyzing key outage and network information, OMS can help in reducing the SAIDI. Shorter outage duration provides benefits to customers in large, while the automation and information management capabilities of OMS can increase workforce productivity and reduce operational costs.

Table 8-2 presents a relatively conservative view of the potential impact of a best practice OMS on PSE SAIDI. The extent of improvement is different for the different phases of the process. For example, the integration of OMS with EMS/SCADA and AMI systems, and the incorporation of the GIS data will significantly improve the outage detection, restoration/switching plan and restoration verification functions.

	Current SAIDI		OMS Improvements	Future SAIDI	
	Contribution to SAIDI	Minutes		% Improvement	Minutes
Outage Detection	***5%***	**6.8**	GIS Network Connectivity and Integration with AMI, SCADA, IVRU and Trouble Call Management	**30%**	**4.8**
Damage Assessment	***15%***	**20.4**	GIS maps, integration with mobile devices, network analysis, integration with Damage Assessment tool	**25%**	**15.3**
Restoration/Switching Plan	***10%***	**13.6**	Power Flow analysis, OMS swithching plan application	**25%**	**9.5**
Resource Dispatch	***8%***	**10.9**	OMS crew dispatch function, Integration with mobile diaptcah	**20%**	**8.2**
Restoration	***57%***	**77.5**	GIS Information, Coordinated operations through OMS	**8%**	**71.3**
Verification	***5%***	**6.8**	Integration with AMI for verification, Integration with mobile and SCADA	**40%**	**4.1**
Total	***100%***	**136.0**		***17%***	**113.1**

Table 8-2 Estimated Impact of OMS on Outage Duration Index

For crew dispatch, the information from the detection phase is used to ensure that the right resources are deployed at the right time to the right place. As the number of crews is limited, prioritization based on the impact of the outage would facilitate a reduction in SAIDI. For instance, prioritizing large area outages over low load individual complaints would reduce the total average down time per customer. Integration with Mobile Devices and the GIS would provide near real time access to information and facilitate in locating the nearest available crew (least travel time) with adequate capacity and requisite skill sets and also to plan and schedule the job.

As is shown in Figure 8-2, the benefits will increase with the proposed phased deployment and change management schedule. The OMS will deliver far more significant benefits for major outages with a multi-day duration. The reduction in outage duration is expected to improve considerably with a larger storm outage, for example, a five day outage may be reduced to three or four days due to optimized restoration process and crew dispatch.

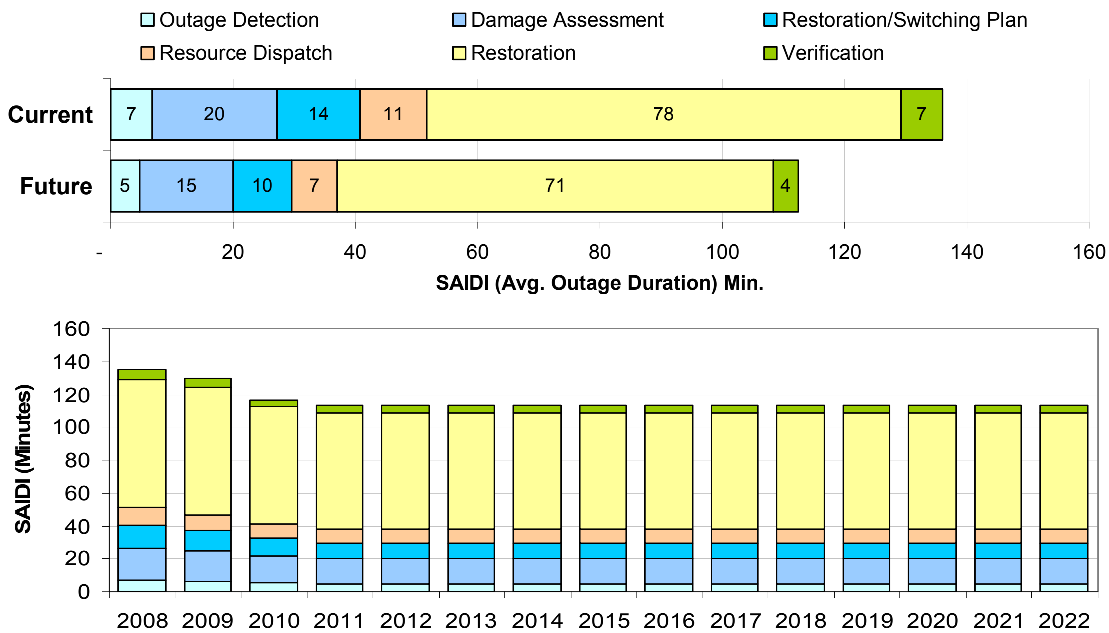

Figure 8-2 Improvements in SAIDI as a result of OMS deployment

8.2.2 Benefits Quantification

OMS capabilities and resulting reduction in outage duration delivers benefits to PSE and to PSE customers. The societal benefits are significant, especially for commercial and industrial segments of the PSE customers. Hard benefits to PSE are primarily a result of improvements in workforce productivity.

8.2.2.1 PSE Benefits

Section 8.1 presented a narrative list of OMS operational benefits. To quantify the value of these benefits we assumed that an aggregate 20 FTEs of PSE resources and 25 FTEs of Service Provider resources are utilized in all functions associated with outage management and system restoration. This is a levelized figure, considering that a large number of resources are deployed during major storm conditions. KEMA has also assumed that a total of $5M of non-labor costs is incurred per annum in support of the restoration process, including truck rolls, accommodations and other direct costs. PSE incurs significantly larger direct costs during major storms. These assumptions are summarized in Table 8-3.

Levelized Labor Utilization for Outage Management			Cost
PSE FTE's involved	20	FTE	$ 2,880,000
PSE Labor Hours Used	36,000	man-hours	
Service provider FTE's involved	25	FTE	$ 4,500,000
Service Provider Labor Hours Used	45,000	man-hours	
Total Labor Used for Outage	**81,025**	**Man-Hours**	
Total Direct Costs and Damage Payouts	**$5,000,000**		

Table 8-3 Assumptions used for outage management labor utilization

Table 8-4 presents the annual operational benefits of the OMS assuming that on the average there will be an improvement in workforce productivity at a level equal to the reduction in the outage duration presented in Section 8.2.1.

Workforce Productivity Improvements	**Hours**	**($000)**
PSE Resources	5,472	$438
Service Provider Resources	6,840	$684
Total Productivity Savings	12,312	$1,122
Saved Direct Costs and Damage		**($000)**
Equipment utilization, Truck rolls and Damage Claims		$841
Increased Revenue Due to Shorter Outage	**MWh**	**($000)**
Additional MWh sold	1,100	$85
Total OMS Benefits for PSE ($000)/Year		**$2,048**

Table 8-4 Annual operational benefits of OMS

The labor hours saved due to the implementation of an OMS can be applied to improve call center operations, and to field maintenance, inspections, vegetation management and other customer service related activities, thus improving the level and the quality services offered by PSE.

8.2.2.2 Customer Benefits

Over the last 20 years, there have been several studies by electric utilities and other organizations to better understand the Value of Electric Service (VOS) by conducting customer interruption or outage cost studies. Under sponsorship of the U.S. Department of Energy in 2003, the Lawrence Berkeley National Laboratories (LBNL)[8] conducted an effort to combine the results of previously available studies into a

[8] A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys – LBNL Report 54365 - November, 2003

meta-dataset and extract information regarding cost of outages under different scenarios for large commercial and industrial (C&I), small-medium C&I, and residential customers across the large database for different regions in the US. Later in 2004 the LBNL published another study titled “Understanding the Cost of Power Interruptions to U.S. Electricity Consumers”[9]. Another study conducted by David Layton, University of Washington, et. al. [10] focused on cost of outages for residential customers.

Figure 8-3 presents one of the results of the LBNL study for C&I customers. As can be seen, the cost of outage peaks around the 8th hours, primarily due to business work hour structure. Figure 8-4 presents cost of outage for residential customers (U of W study) with sharp increase during the early stages of the outage and a linear growth with time.

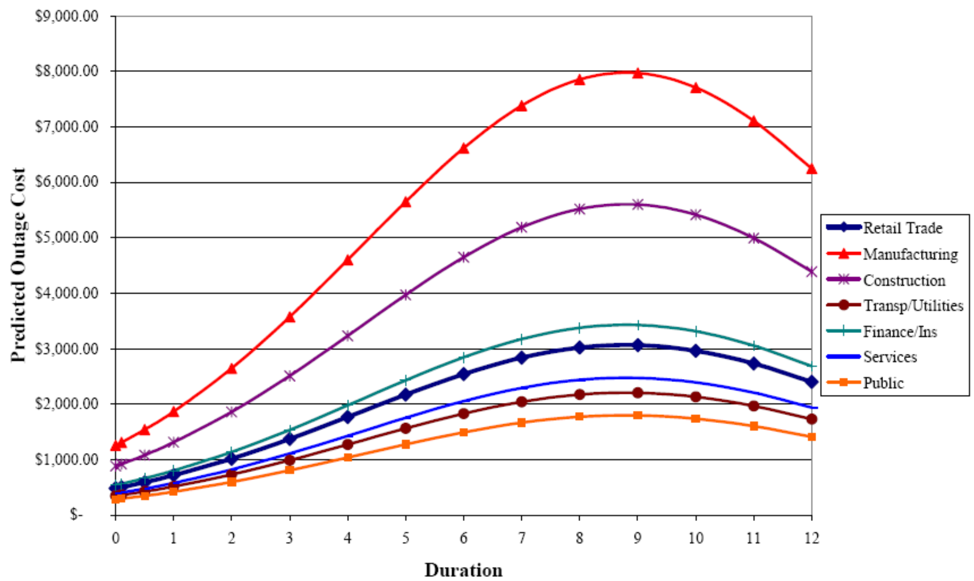

Figure 8-3 Predicted outage cost by C&I customer type – LBNL Study

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[9] Understanding the Cost of Power Interruptions to U.S. Electricity Consumers - LBNL-55718 - *Kristina Hamachi LaCommare and Joseph H. Eto* - September 2004

[10] The Cost of Power Outages to Heterogeneous Households – David F. Layton, University of Washington & Klaus Moeltner, University of Nevada, Reno - October 2004

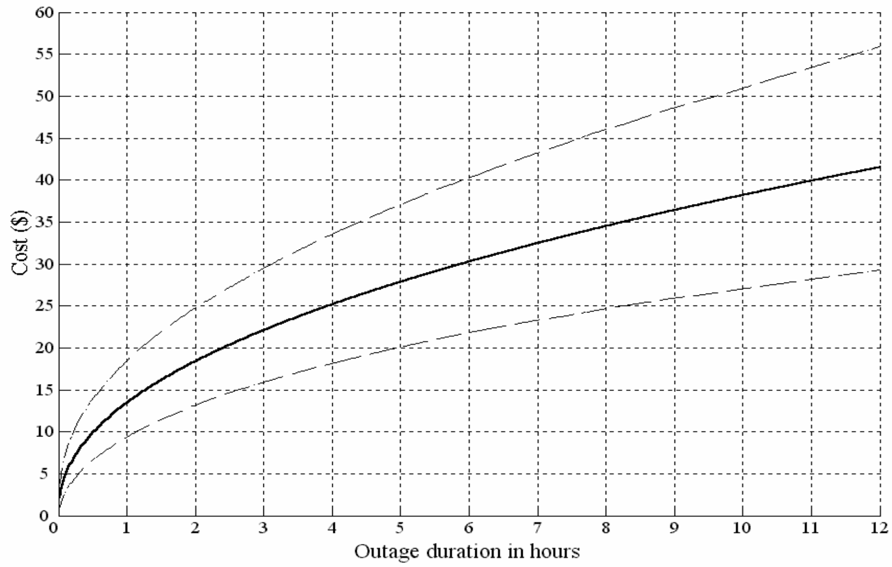

Figure 8-4 Estimated Cost of outage for residential customers (mean and 95% confidence intervals averaged over all households)

The results of these studies are used to quantify the potential benefits of reduced outage duration for PSE customer base. For this purpose, an average incremental cost of outage, i.e., cost of an additional minute of outage or the average slop of the outage cost curve, is computed per customer class, as is shown in Table 8-5. These averages are then used to compute the financial benefit to PSE customers.

Outage Duration (min)	Residential			Small C&I		Large C&I	
	Summer	Winter	UW Study	Summer	Winter	Summer	Winter
0	0	0	0	0	0	0	0
60	$2.9	$3.3	$13.5	$1,200	$1,800	$8,200	$20,000
480	$7.2	$8.3	$35.0	$4,400	$6,300	$41,000	$105,000
Incremental Cost ($/Min)	$0.0132	$0.0154	$0.0649	$8.60	$12.24	$82.72	$212.72
Average Incremental Cost ($/Min)	$0.04			$10.42		$147.72	

Table 8-5 Outage Cost per Customer Class - LBNL and UW Studies (Costs in $s)

Table 8-6 presents the estimated annual benefit of the OMS implementation for PSE customers (the Societal Benefit), assuming that the OMS will result in 17% reduction in the average outage duration for PSE.

	Number of Customers	Benefits/Year ($000)
Residential Customers	942,352	$853
Small/Medium C&I Customers	131,679	$31,358
Large C&I Customers	1,665	$5,623
Total	**1,075,696**	**$37,834**
Electric Load Growth Rate/Year	1.59%	

Table 8-6 Annual benefits of 17% reduction in outage duration for PSE customers

8.3 Geographic Information System Benefits

GIS is a foundational application that supports many business functions and users across the utility operational enterprise. GIS is typically viewed as the data source and the system-of-records for the distribution network connectivity information needed for the OMS application.

8.3.1 Operational Benefits – Qualitative Discussion

The following is a summary of the benefits of a fully implemented GIS by different application areas. Achievement of benefits, however, depends on the specific functionality and applications implemented in the GIS, including available data and integrations.

8.3.1.1 Maps and Records Department

As the primary user of the GIS data, Maps and Records Department will gain significant productivity improvements with implementation of a GIS. A list of some of these benefits includes:

- Consistent maps across the entire service territory (consistent symbols, text, line weights, naming conventions, etc.);
- Productivity increase in facility map creation;
- Productivity increase in facility map maintenance and update (as-builts);
- Labor savings by reduced custom map production;
- Labor savings in land base maintenance;
- Labor savings in map query and reporting;

- Labor savings in special data analysis and summarization (e.g., total number of bare pipe in the system, number of structures of a specific type, certain vintage of conductor length and location, etc.);
- Maps are more accurate, consistent, complete and timely;
- Maps are in a format that is easier to query, view and plot, especially using web technology;
- Supports field map view and redline; and,
- Ability to share data, both internally and externally.

8.3.1.2 System Planning

The Planning Department is a major user of maps and records in support of their load analysis, expansion planning studies, and other studies and analysis needed for support of the power system operations. Some of the benefits associated with GIS include:

- Labor savings in initial model creation by using the electric and gas network in GIS;
- Labor savings in model updates by importing the latest electric and gas network version;
- More simulations and studies possible annually;
- Accurate planning models result in capital savings by not having to overbuild the system;
- Models run with latest as-built information;
- Improved communications of analysis results by displaying results in GIS rather than just in Stoner; and,
- Supports reliability analysis.

8.3.1.3 Engineering Design

GIS benefits in support of engineering design activities include:

- A GIS integrated to a design software will provide existing land base and facility information for engineering designs (new line extensions, refurbishments, relocations, etc.). This will avoid having to redraw this information for the new design;
- Integration of the GIS to a planning system will assist in load flow calculations for new designs;

- Creation of new designs using the design software will improve the accuracy and increase the productivity of mapping as-builts because the land and facility reference is the same as what is in the GIS; and,

- Map revision of the as-built information once construction is completed is faster because the land base and existing facility data is of the same source file and new land base and facilities can be merged in place.

8.3.1.4 Maintenance Planning

Some of the GIS benefits for maintenance planning include:

- Labor savings in planning maintenance work using current and complete facility information;

- Labor savings in the field as a result of accurate maps for locations and facility access;

- Productivity increase on vegetation management planning and work performance and avoiding potential encroachment outside of easements;

- Improved capital maintenance plans using more accurate and complete facility data in an easier to use format;

- Supports development of the annual O&M plans for inspections and maintenance; and,

- Supports development of the annual capital plans for asset replacements, refurbishments and relocations.

8.3.1.5 System Operations

The GIS capabilities will support the replacement of manual wallboard maps with electronic wallboard displays providing updated information, eliminates manual updates of facilities, flexibility of viewing, panning and zooming, and overall map navigation.

8.3.1.6 Real Estate Rights of Way and Vegetation Management

GIS provides key support for real estate rights-of-way:

- Having easement and rights-of-way information on PSE facility maps will avoid duplicate drawing of this information on assessor maps; this information can be stored on the corporate GIS and readily accessible to those who need this information; access can be controlled, and can be shared with others as required;

- Location of distribution control switches and premise access information to those switches from roads will help during storm conditions;
- Improved public relations by not over encroaching onto private property when doing vegetation management and staying within the PSE easement;
- Manage key data associated with vegetation location, type and trimming and management requirements;
- Encroachment management of gas and electric corridors; and,
- Encroachment management of aerial easements by buildings (potentially a safety issue).

8.3.1.7 Tax and Franchise Calculations

- Faster analysis of facilities contained within specific tax zones and franchise areas;
- Algorithms can calculate nested tax areas within other areas (polygons within polygons) quickly;
- More accurate and consistent tax payment amounts; and,
- Faster report generation of results.

8.3.1.8 Regulatory Affairs and Reporting

End users can develop presentation material using the GIS and on-line tools for regulatory and public presentations. GIS data, with census information with various population and geographic information overlays, can support reporting and analysis activities.

At some point in the future, regulatory agencies may require PSE to implement a geospatial asset management system to improve efficiencies and ensure delivery of services. That mandate will likely come with little warning when money and personnel are unavailable due to competing priorities. PSE will have more control over getting the system that best fits their needs if they proactively implement a GIS rather than wait until mandated to do so.

8.3.1.9 Marketing (New Business)

- Facility maps can be used for the analysis, forecasting and planning of new business areas for both gas and electric;
- Identify non-customers along existing gas mains for potential gas service; and,

- Supports pro-actively marketing services to certain classes of customers or customers within certain geographic areas.

8.3.1.10 Gas Application benefits

In the gas distribution applications area GIS delivers key support in the following areas:

- Supports leakage surveys and leak management;
- Location of CP points improves locating ease;
- MAOP analysis;
- Critical valve location identification and isolation area analysis;
- Critical valve maintenance and inspections;
- Regulator station locations for maintenance and inspections;
- Supports BTU analysis; and,
- Supports maintenance and inspection of non-critical valves.

8.3.1.11 Gas Compliance

- Meet DOT requirements for Distribution Integrity Management Program (DIMP).

8.3.2 Benefits of GIS for OMS

The implementation of a GIS to just support an OMS has benefits of its own. Implementation of a GIS forces the data conversion of electric facility and land information from paper maps and map images. The resulting conversion process imposes data structure and quality to the data to allow its use not only for OMS but for other applications as well, such as system planning. The converted data, while not complete enough to support all applications, will still provide value to the organization for people to query, view, and output this information, both in the office and in the field.

During storm conditions, GIS delivers particular benefits in the following areas:

- Accurate facility maps for First Responders, Service Provider and foreign crews;
- Supports the electronic storm board in regions;

- Accurate information on access to reach certain critical circuit switches and devices (land easement information);
- Ability to quickly provide facility maps to foreign crews;
- Provide optimum routing and route planning of crews; and,
- Ability to support damage assessment extent and restoration planning.

The GIS also has the required tools and functionality to effectively maintain this data in an electronic state, making the posting of as-built information to the maps more efficient. Thus, this data can be maintained in a timely and accurate manner.

8.4 GIS Benefits (Quantitative Analysis)

The GIS benefits can be quantified based on workforce productivity and the savings that could result in capital project expenses and other capital costs. The following subsections provide estimated benefits for different functional areas assuming a full implementation of GIS capabilities at PSE.

8.4.1 Maps and Records Department

Significant productivity improvements for production, maintenance and reporting of maps and related records are expected with a full GIS implementation. With the introduction of the GIS, some of the existing drawing tools and map maintenance software can be retired creating savings in software maintenance costs and related tools utilization.

Maps and Records Department	Base Cost ($000)	% Improvement	FTE Improvement	Cost Savings ($000)
Labor Savings				
Map Production & Maintenance	5	30%	1.50	
Map Query and Reporting	4	30%	1.20	
Data Analysis and Summarization	3	30%	0.90	
Total Improvement		**30%**	**3.60**	**$562**
Capital Costs				
Existing S/W Maintenance and Licenses	$600	70%		$420
Tools and specialized apps	$400	50%		$200
Total				**$1,182**

Table 8-7 Maps and Records Benefits

8.4.2 System Planning / Engineering Design

GIS will assist the planning and engineering staff in network modeling, creation and update of network and facility layouts, and the overall engineering design activities. Also, use of accurate GIS data can improve the planning analysis and asset management activities resulting in an estimated 1% reduction in capital costs associated with asset management and system expansion.

System Planning/Engineering Design	Base Cost ($000)	% Improvement	FTE Improvement	Cost Savings ($000)
Labor Savings				
Model Creation & Update, Forecasting	2	30%	0.60	
Engineering Design Activities	2	30%	0.60	
Total Improvement		**30%**		**$250**
Capital Costs				
Improved accuracy and effectiveness of planning analysis - Asset Managemnent	$50,000	1%		$500
Total				**$750**

Table 8-8 System Planning / Engineering Design Benefits

8.4.3 System Maintenance

Use of GIS for obtaining rights-of-way and permit information and for as-built drawings in support of maintenance activities could bring a considerable level of efficiency to field maintenance activities. Also, the availability of accurate GIS data on mobile devices could optimize use of trucks and other field equipment resulting in additional savings.

System Maintenance	Base Cost ($000)	% Improvement	FTE Improvement	Cost Savings ($000)
Labor Savings				
Real Estate Rights of Way, Easements, Permits	2	30%	0.60	
Maintenance Activities	10	10%	1.00	
System loading analysis	2	10%	0.20	
Total Improvement		**13%**		**$374**
Capital Costs				
Truck rolls and equipment usage	$1,000	10%		$100
Total				**$474**

Table 8-9 System Maintenance Benefits

8.4.4 Load Forecasting

Use of accurate GIS maps with customer information overlays can improve load growth forecasting. Better load forecasts can optimize long-term energy contracts and facility planning with an estimated 1% improvement in facility upgrade costs, and 1% improvement in long term energy contracts.

Improved Load Forecasting	Base Cost ($000)	% Improvement	FTE Improvement	Cost Savings ($000)
Labor Savings				
Forecasting Effort	0.1	40%	0.04	$9
Capital Costs				
Spending on Substation Upgrades due to load growth	$4,000	1%		$40
Improved Energy Scheduling and Long Term Contracts	$20,000	1%		$200
Total				**$249**

Table 8-10 Load Growth Forecasting Benefits

8.4.5 Tax and Franchise

GIS can help staff productivity in preparation of periodic and annual data needed for support of tax and franchise fees.

Tax and Franchise/ Regulatory Reporting	Base Cost ($000)	% Improvement	FTE Improvement	Cost Savings ($000)
Labor Savings				
Reduced Effort For Tax Computation	0.3	70%	0.21	$33
Total				**$33**

Table 8-11 Tax and Franchise Benefits

8.4.6 Vegetation Management

Overlays of vegetation and rights-of-way information on GIS maps, as well as integration of aerial views with the GIS maps can improve the overall efficiency and productivity of the vegetation management process. Also, GIS based planning and scheduling activities can reduce transportation and field equipment usage costs.

Vegetation Managemet	Base Cost ($000)	% Improvement	FTE Improvement	Cost Savings ($000)
Labor Savings				
Veg. Mgmt Planning & Scheduling	2	25%	0.50	
Inspections & Reporting	5	10%	0.50	
Execution	20	15%	3.00	
Total Improvement		**15%**		**$666**
Capital Costs				
Truck rolls and equipment usage	$300	10%		$30
Total				**$696**

Table 8-12 Vegetation Management

8.4.7 Gas Applications

Similar to electric applications considerable benefits can be gained in planning operations and maintenance activities associated with gas transmission and distribution system. Some of the specific benefits include gas distribution integrity management support, support for leak survey and leak management, and cathodic protection activities. The GIS can also help in optimizing deployed capital assts and maintenance activities.

Gas Applications and Compliance	Base Cost ($000)	% Improvement	FTE Improvement	Cost Savings ($000)
Labor Savings				
Gas Distribution Integrity Mgmt	4	30%	1.20	
Planning, enginnering & maintenace	15	15%	2.25	
Leak Survey and Leak Mgmt	5	20%	1.00	
Cathodic Protection	4	20%	0.80	
Total Improvement		**19%**		**$874**
Capital Costs				
Capital deployed and Maintenenace Actibities	$20,000	2%		$400
Total				**$400**

Table 8-13 Gas Applications

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9. Cost Benefit Assessment

The cost benefit assessment brings together the project costs and benefits over the expected life of the project. The OMS and GIS capabilities will transform some of the existing PSE business practices with the longevity beyond the life of the specific computer hardware and software used. The analysis includes on-going maintenance costs for the invested capital providing for a normal technology upgrade when required. The overall business case is assessed based on a 15-year discounted NPV analysis considering both the capital and O&M costs.

For this analysis the following Discount Rate and cost escalation (inflation) rates are used.

REDACTED

Discount Rate	8.5%	Per Annum
Cost Escalation Rate	3.0%	Per Annum

9.1 OMS Cost Benefit Analysis

The implementation of the OMS project is expected to span over three years with a capital cost o[redacted] and [redacted] in each respective year. In 2008 the required hardware and base software will be acquired with the ODM put into operation in the 3rd quarter of 2008. The base OMS functionality will be rolled out in Q3 of 2009, with full functionality released in 2010.

Figure 9-1 illustrates the estimated costs and benefits profile of the OMS project based the discussion provided in Section 7 and Section 8 of this report. The O&M costs are escalated based on the rate presented above.

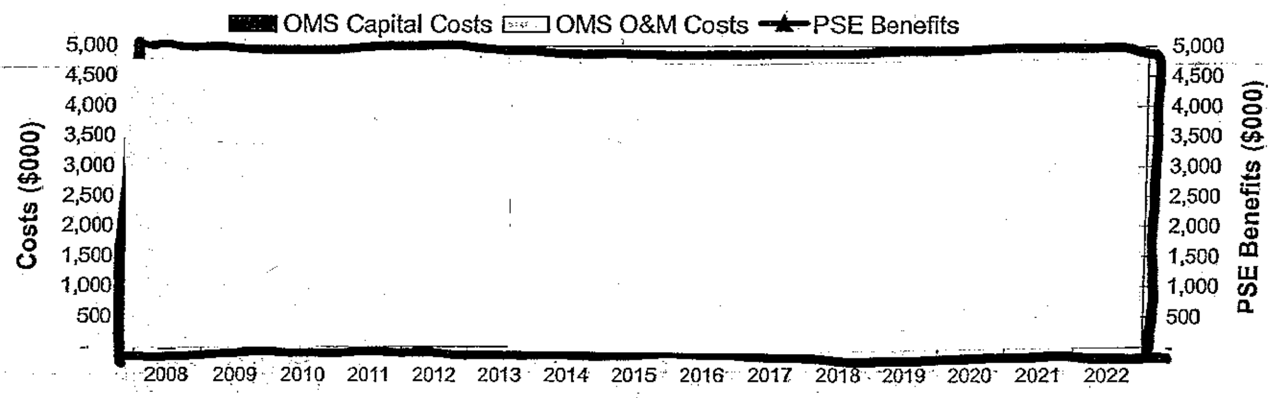

Figure 9-1 OMS Costs and Benefits

The discounted NPV of cost and benefits are provided in Figure 9-2. As is illustrated the OMS project results in a computed NPV benefit of $5.6M over its life when considering only the operational benefits of the technology.

Net Present Value Over 15 Years ($000)		
Productivity Gains	$	9,220
Direct Cost Savings	$	6,915
Revenue Enhancement	$	702
Capital Cost	$	[redacted]
O&M Costs	$	[redacted]
Net Benefits	$	[redacted]

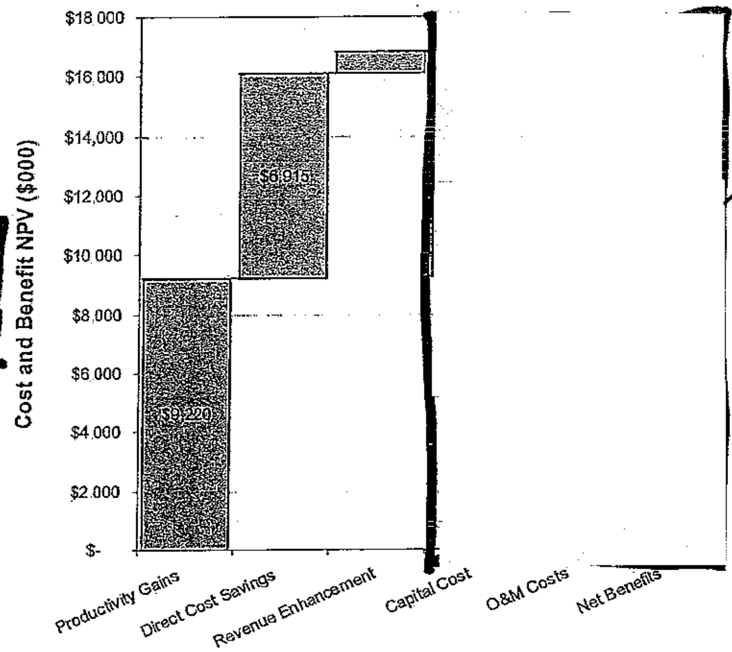

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Figure 9-2 OMS Cost Benefit Analysis Summary (PSE Benefits)

As presented in Section 8, the implementation of the OMS and the improvements in the overall outage management capabilities and the potential reduction in the average outage duration delivers significant benefits to PSE customers. Figure 9-3 is an estimated profile of the societal benefits of the OMS. The benefit calculations include the estimated customer number/load growth (based on the current annual rate) and the cost escalation factor.

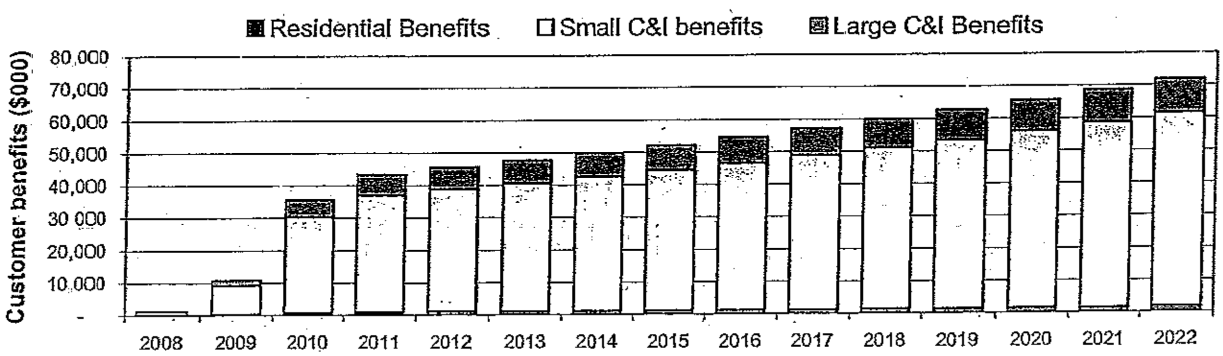

Figure 9-3 Societal Benefits of OMS

The above analysis results in a positive business case for the OMS project.

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9.2 GIS Cost Benefit Analysis

The implementation of the GIS is expected to span over four years with the base electrical connectivity models (the base project) implemented by Q2 of 2009 in support of the OMS roll-out. Implementation of the incremental capabilities (Section 6) is scheduled to begin in 2009 and last through 2011. The base project is expected to require [redacted] of capital in 2008 and about [redacted] in 2009. This includes the base GIS software license, land base and required hardware. The incremental projects (full electrical asset modeling and implementation of Gas applications) are expected to require approximately $1.3M of capital budget in 2009, [redacted] in 2010 and [redacted] in 2011. The bulk of the costs are associated with GIS data modeling and conversion efforts. The O&M costs for hardware and base software to be effective following the delivery of the initial base package. The costs and benefits profile of the project are illustrated in Figure 9-4.

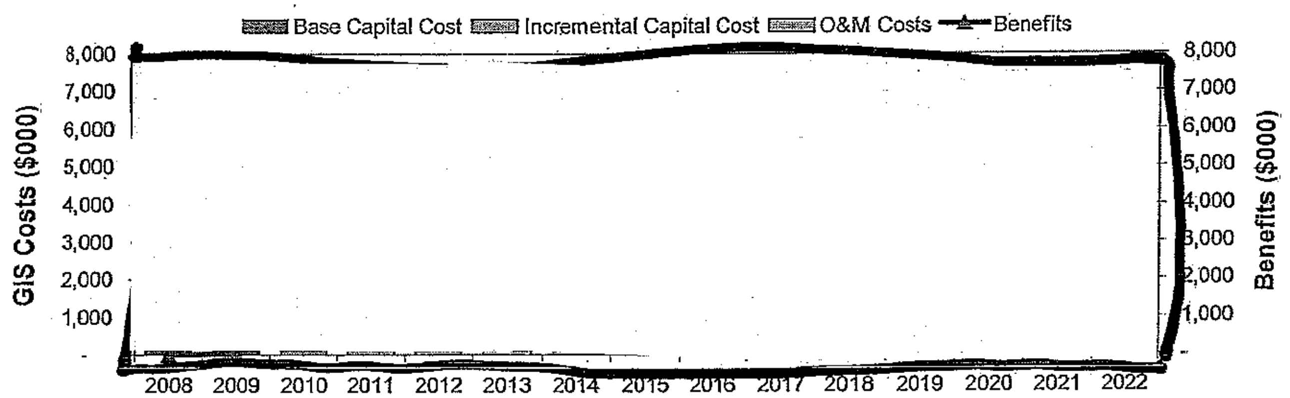

Figure 9-4 GIS Costs and Benefits

The discounted NPV of GIS costs and benefits over the 15 year time horizon analysis are presented in Figure 9-5. As is illustrated the GIS, when fully adopted, delivers significant benefits across various functional areas. The NPV of the project is estimated at a positive value of $20.7M.

Net Present Value Over 15 Years ($000)	
Maps and Records Dept	$ 10,110
Systems Planning & Engineering	$ 5,079
Systems Maintenance	$ 3,554
Improved Load Forecasting	$ 2,006
Tax and Franchise/Regulatory Reporting	$ 238
Vegitation Managmenet	$ 5,380
Gas Apps and Compliance	$ 9,349
Capital Costs	[redacted]
O&M Costs	[redacted]
Net Benefits	[redacted]

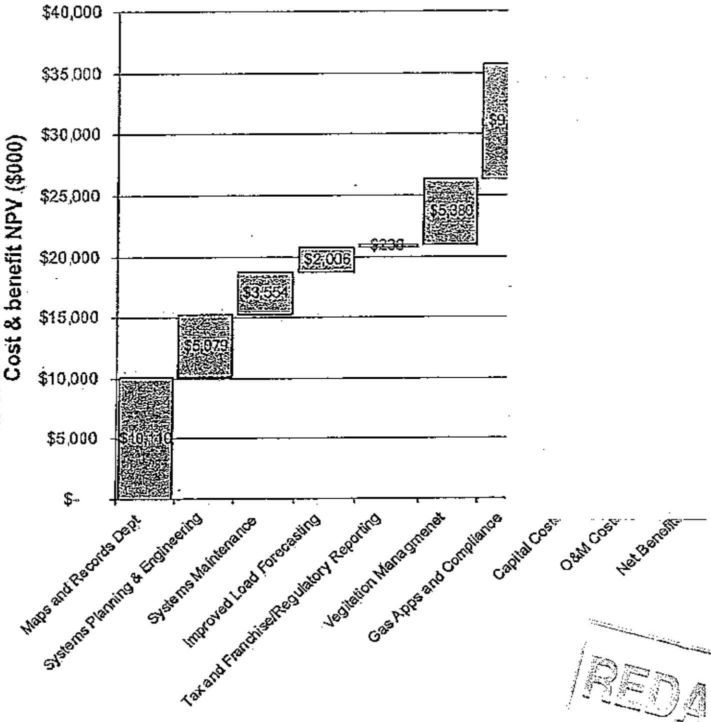

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Figure 9-5 GIS Cost Benefit Analysis Summary

9.3 Total Project – OMS and GIS

Considering the interdependencies of the OMS and GIS projects, as is shown in Figure 9-6, the business case for the proposed program is positive at an estimated total NPV cost of $26M over the 15 year life of the project and the total net benefit to PSE of $26M using a discounted NPV calculation.

Net Present Value Over 15 Years ($000)	
OMS Benefits	$ 16,837
GIS Benefits	$ 35,716
OMS Costs	[redacted]
GIS Costs	[redacted]
Net Benefits	[redacted]

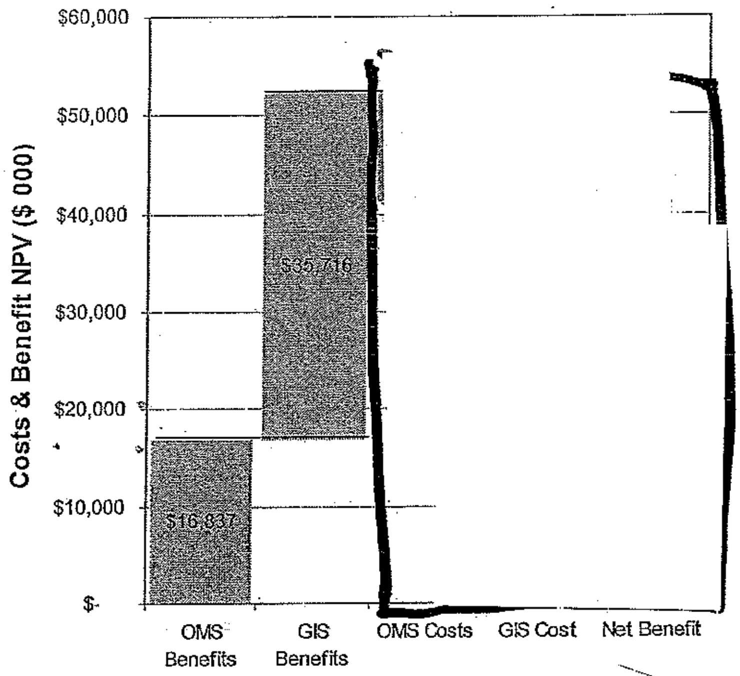

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Figure 9-6 Project Business Case Summary

9.4 Program Risks

The potential risks of the proposed OMS and GIS projects are discussed in this section.

9.4.1 OMS Project

Distribution Network Connectivity Model

OMS requires distribution network connectivity model. The currently available source for this data is the SynerGEE planning models. These models may not be complete or accurately represent all PSE facilities and service territories. It is assumed that the base GIS project will covert the available SynerGEE models to GIS format and those will be used for the OMS application. A full assessment of the SynerGEE models and their capabilities and limitation has not been made.

Integration

The OMS will require integration with a number of existing PSE systems including CLX, IVRU, EMS/SCADA, MDW and Mobile. Detailed design specifications for these interfaces have not yet been developed. The effort and costs associated with these interfaces are estimated based on similar activities elsewhere.

The integration with CLX and IVRU requires both real-time interfaces as well as batch interfaces. Discussions have begun with ADS to review integration approach and scope the effort for CLS/OMS interfaces. The batch integration to/from CLX includes initial and incremental batch updates of customer data.

Risks for the SCADA/DMS interface will be managed through the specification and implementation of Off-The-Shelf ICCP gateway software available from either the SCADA/EMS vendor or the OMS vendor.

Migration of Existing Functionality

Certain existing functionality, e.g., DMS incident reporting capabilities and certain aspects of the CLX outage management capabilities need to be ported to OMS. Use of COTS capabilities of vendor OMS products may require changes in these capabilities. Such changes will have to be evaluated during the selection of the OMS vendor.

Change Management / User Training

Because System Operators and Dispatchers are currently using a largely manual set of processes centered on the existing systems, adopting the automated business processes for the selected OMS should not be too challenging. However, transition from the existing practice, changes in business process, and the need for parallel operations need to be well planned. Change Management and training costs are included in the projected budget. Further planning and fine tuning is required and perhaps best done following selection of the OMS vendor.

Project Schedule/ Project Management

The proposed project schedule poses a certain level of risk with detailed specifications, RFP, vendor selection and Outage Data Mart implementation in 2008. It will be important to target minimal customization when selecting the OMS vendor. Upon vendor selection, a well-defined project charter, project scope, project plan, and contract will be critical. The project team must be aware of the systems and integration required for the timely completion of this project. Managing project change controls will be critical to prevent scope creep.

Hardware/IT Resources

The OMS is considered mission-critical and downtime should be kept to an absolute minimum. Hardware deployment and IT support will need to factor in the possibility of maintaining and managing environments for “Production,” “Testing,” “Model Build,” and “Patches.”

Backup Site/High Availability

The needs for high OMS availability and support for a remote backup site must be factored into the requirements as a part of the vendor selection criteria.

9.4.2 GIS Project

During Implementation:

Maintaining Business as Usual

It will be a challenge to keep business running as usual until the conversion and integration is complete and the new business processes are fully implemented. Paper records will be in demand.

Project Schedule/ Project Management

The proposed project schedule poses a certain level of risk with specifications, RFP, vendor selection and the electric connectivity model conversation (transmission and distribution) to be completed by Q2 of 2009. Upon vendor selection, a well-defined project charter, project scope, project plan, and contract will be critical. The project team must be aware of the phased scope for the timely completion of the initial phase of the project. Managing project change controls will be critical to prevent scope creep.

Data Conversion and Quality Control

Success of the GIS implementation project heavily depends on the data conversion and Q/C strategy. Proper planning, use of automated data conversion and mapping , and use of all existing facilities, assets and mapping data (Maps and Records, SAP, SynerGEE, EMS, PSS/E, etc.) will be an important consideration. Detailed planning should accompany the GIS / Data Conversion vendor(s) selection process with an assessment of data conversion approach and data conversion tools.

Integration

GIS will require integration and data synchronization with SAP and CLX, and data exchange with OMS, Mobile and number of other applications. Detailed design specifications for these interfaces have not yet been developed. The effort and costs associated with these interfaces are estimated based on similar activities elsewhere.

After Implementation:

GIS Data Maintenance

The project may ultimately fail if data is not kept current and accurate. Good decisions cannot be made with outdated and inaccurate data. If data quality were to degrade in the future, the value of the entire implementation will be questioned. Organizational roles and responsibilities for the data maintenance need to be defined and enforced. This includes the role of field maintenance and engineering crews that modify the facility configurations and conduct system expansion activities.

9.5 Risk Mitigation

Throughout the vendor selection process, procurement, contract negotiations, implementation, deployment, and maintenance, risk mitigation will focus on ensuring that the business benefits are achieved and that the project deliverables are on schedule. The following methods will be employed to ensure that risks are assessed and mitigated:

- The project will use Commercial-Off-The-Shelf (COTS) products in its implementation to control costs, meet timeframes, and achieve benefits;
- The project will focus on software configuration and keep customization to a minimum to enable ease of vendor upgrades, updates, and changes;
- The project will conform to and support PSE IT architecture requirements and guidelines, ensuring compatibility with IT infrastructure already in place at PSE; and,
- Any major risk areas (e.g., the Data Model) will be addressed with rapid prototyping to ensure that a viable solution is produced.

Appendix A: Outage Management Systems

The Outage Management System (OMS) is a software tool that provides the functionality to manage the overall cycle of outage and outage restoration for an electric utility. It is generally a commercial-off-the-shelf (COTS) software package that requires configuration and perhaps customization to meet a specific utility's business needs. The OMS provides the functionality to help detect, analyze, locate, restore, and report on outages on the distribution system. It is used for both unplanned and planned outages. Special functionality is included to manage storm conditions and power flow analysis for planned switching (clearances). The OMS provides status updates and notifications to both internal and external entities. It provides executive-level status of the outage activity. It also provides outage statistics for the calculation of reliability indexes, such as System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) based on timed switch operations and customers affected. The OMS has capabilities for the generation of reports.

Perhaps the most important function of the OMS from a customer service standpoint is the ability to provide timely and accurate customer specific information about an outage event. The OMS provides two critical pieces of information to customers without power:

- The utility knows that I am out of power
- How long will I be out of power (what is the estimated restoration time?)

The OMS has functionality to capture this information, relay it to the customer call center through the Customer Information System (CIS) and IVR, and also provide this information to others within the organization that may interact with external agencies like the media and public service organizations. As the condition of the outage changes or restoration is made, this updated information is conveyed as appropriate.

The network outage analysis functionality of the OMS enables faster outage detection, outage cause analysis and location of the outage. This contributes to faster outage restoration times. It also provides vital information to engineers to take measures to reduce outage causes in the future.

The OMS Functionality

The OMS requires an accurate electric network connectivity model that reflects the as-operated distribution network from substation to customer connection points. The model requires that all devices and phasing are defined and correct. The electric connectivity model is generally defined in the Geographic Information System (GIS) as the as-built or as-constructed configuration of the electric system. Through a data extract process and a model build process, the electric network data and land base data are placed into the OMS. The as-operated state of electric devices are established during this model build process. Customer to circuit relationships are generally held in the CIS and this information is also sent to the OMS during the model build process. Once this network model is complete, the OMS can use it for outage analysis. This network model is generally updated nightly to reflect the current state of the distribution electric network.

In operation, as customers report "lights out" outages to the utility, this information is captured either by the customer service representative in the call center, or the IVR. This information is sent to the OMS for analysis. Single premise outages are handled as such. Using the Automated Meter Reading (AMR) infrastructure, it is possible to "ping" the meter to determine whether the meter is truly out of power. For multiple outage situations, customer calls will continue to be received. The OMS will take these calls and place them on the related circuit. It will then perform a network trace to roll-up the outages to the most probable device that is causing the outages. As more trouble calls are received, as in a large outage event, the roll-up may continue until a major protective device is reached. In this manner, the dispatcher in System Operations can send a first responder directly to the location of the open protective device. Additional analysis, however, may be required to identify and isolate the actual cause of the outage.

The OMS is considered an operations tool and as such is generally under the control of the System Operations Department, with support from Information Technology. System Operations is the owner of the as-operated system status information. As a high-availability system, it is generally configured in a fail-over environment with RAID technology.

The main features of a modern outage management system are summarized here:

- Ability to model the distribution system in sufficient depth and breadth for outage analysis and restoration
- Provide outage status information to the customer call center through the CIS and IVRU
- Utilize the spatial data about the distribution system and equipment from the GIS
- Integrate and apply all necessary real-time operating information from EMS/SCADA, DMS, IVR, AMI, and direct field observations
- Dynamically manage network connectivity to the as-operated configuration of the network
- Schedule and dispatch resources for outage analysis and service restoration if the OMS is integrated to a MWF.
- Monitor and track distribution system performance over time including SAIDI, SAIFI, and CAIDI indices
- Generate reports for analysis, record keeping, and regulatory compliance
- Communicate with back office applications for work management

- Communicate with others within the organization who deal with external agencies like the media
- Provide analytical functions to assist in decision making for faster outage response
- Provide up to date restoration information to customers
- Provide analytical tools for outage prediction, feeder reconfiguration, etc.
- Ability to perform reliably under changing operating conditions (Normal, Storm) and with partial availability of data
- Provide a platform to capture accurate reliability data associated with equipment faults and customer interruptions
- Track equipment failures automatically, allowing for failure trends and rates to be analyzed

The Future State Process Flow

The following is a typical best practice future state process flow for outage management using an integrated OMS.

Taking Trouble Calls: Outage events are triggered by one or more of the following from external entities (that is, telephone calls coming in):

- CIS
- IVRU
- Call Center Entry
- Web Call Entry (possibly used by a contract call center agency during emergencies)
- Phone call from public agency (police, fire, another utility)
- Direct from large account (C&I)

A trouble event can also be triggered by a device status change from EMS/SCADA, or from monitored distribution devices as part of the distribution management system (DMS).

Trouble Ticket Logging in the OMS, the outage event passes to the OMS for this logging function. The OMS tracks each outage event by individual customer:

- CIS and the IVR will pass the trouble ticket to the OMS
- The OMS will reference the trouble call to the specific customer name and address

Trouble Analysis is performed by the OMS using available calls and the electric circuit model:

- Predictive Analysis of the Outage is performed by the OMS
- Most Probable Device Causing the Outage will be identified (a switch, fuse, recloser)

Notify Key Personnel of Outage Event, the OMS will notify the following of the outage:

- Key Operations and Management
- Key Executives
- Public Relations
- Account Executives when key accounts are impacted

Dispatching the First Responder to the Location:

- Dispatch using the MWF system that is integrated to the OMS

Receiving the Damage Assessment and ETR from the field:

- Normal radio communications (Dispatcher enters data into OMS)
- Best practice is the First Responder enters information into MDT (mobile data terminal) and this gets transferred into the OMS from the MWF system, eliminating the need for the dispatcher to enter this information into the system
- First Responder requests assistance or back-up as necessary

Convey Information to Organization, Internal and External:

- OMS sends status including the estimated time to restore (ETR) to CIS and IVRU to update messages from customers continuing to call
- OMS sends outage status when key accounts are impacted to Account Executives
- OMS sends outage status to Public Relations
- Outage summary and status displayed on Executive Dashboard

- Outage summary displayed on PSE Web for customer query

Outage Restoration is completed in the field:

- Dispatcher sends restoration crew to outage cause location
- Crew makes repairs and restores power
- Notifies dispatch of status using MDT
- May require additional resources to be sent to the site, or any clearances and restoration validations
- System Operations verifies restoration using SCADA, DMS or AMI
- Close trouble notifications
- Status is conveyed to CIS, IVRU, Service Alert and Executive Dashboard

Permanent Repairs are made as required.

- Permanent repairs require initiation by a work order in the work management system triggered by information recorded in the MWF system of the outage area
- The work management system manages the permanent repair process from a resource, material and equipment standpoint

Storm Condition Outage Management

What changes during a storm condition that triggers widespread outages?

- EMS/SCADA device status will come in first ahead of customer calls; then customer calls will begin to flood in at a rapid pace
- OMS will use the EMS/SCADA device status change to perform the predictive analysis
- It will generally show a protective device at the substation level has opened; this does not, however, tell the location or locations of the cause of the outage
- For complete circuit outages, map the customers to the circuits and update the IVRU and CIS to reduce the number of calls that need to be handled by a CSR
- OMS will use the storm condition ETR metrics for ETR notification for customers

- First Responder will still have to drive the circuit to perform damage assessment and provide cause and ETR estimates to dispatch; update CIS and IVR

- Individual calls can still be shown on the outage map, but probably better to just go down to the transformer level rather than individual service during peak of storm

- As restorations occur, use the EMS/SCADA and AMI to validate power restored; trouble crew may still have to validate complete circuit is energized by driving the line; individual protective devices may still be open along the circuit

- AMI will be useful to identify pockets of outages (nested outages) and individual service restorations

- Important during the storm event is for the OMS service alert and executive dashboard applications to continually provide updated information on circuits out, customers out, ETR and any very unusual conditions that may prolong the restoration at certain places

Outage Management Process Flow

The overall generic outage management process and information flow is show in the diagram below. The diagram identifies the various outage management activities mapped to various organizational areas typical in an energy utility.

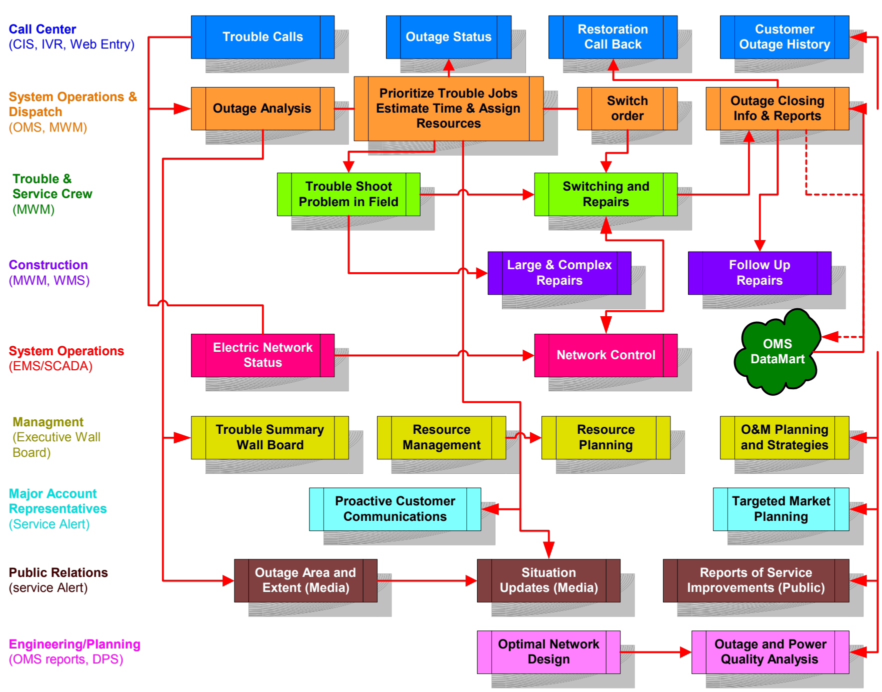


Figure A-1 Outage Management Process Flow Chart

Communicating the Outage Event

An important business value of the OMS is the ability to communicate outage events and status in a timely manner through a broad variety of media. One critical interface, of course, is between the OMS and the customer call center systems, including CIS and IVR. This is a vital feedback loop providing outage status information to the customer call center and to update the IVR message. However, there are other important communicating paths from the OMS to others within the PSE organization.

- Public relations to communicate outage events and status to the media (TV, radio, newspapers)
- Account Executives responsible for large key commercial and industrial accounts
- Organizations and individuals responsible to communicate significant outage events to public agencies and works departments, including police, fire and municipal services
- Key service provider individuals
- PSE Executives and stakeholder managers
- Others who may need to be informed immediately of outage events

The OMS can be configured to enable a variety of approaches to be used for these communications, including cell phone alerts, pager alerts with text messages, email messages and executive dashboard status on the web. The figure below depicts this configuration.

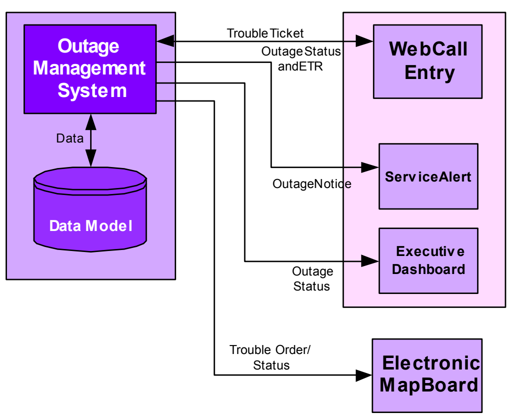


Figure A-2 Managing Planned Outages

Managing Planned Outages

The OMS is also used to perform "clearances" or planned outages. These planned outage events, required to support repairs, maintenance and construction, must be scheduled, communicated and managed as any other outage. The OMS provides the ability to create switch plans and to validate the plan in a "study" mode. This includes safety information such as tags. A power flow module can be initiated on the switch plan to determine the current loads after the switch is performed.

The value of the OMS in managing planned outages is again in communicating the outage event, the on-going status of the outage, and the restoration. This information is conveyed to the customer service call center, to key accounts and utility management. Another important benefit of the planned outage functionality is in its ability to record switching operations as they happen in the field. This can occur either as a field person enters the switching information into a mobile data terminal and sending it to the OMS via the MWF system, or the dispatcher enters the information directly into the OMS as switching is performed and the information is relayed via radio. Once the clearance is restored, this information serves as a record of the actual switching operation performed.

The OMS can also store a library of switch plans for reference and to serve as templates when new switch plans need to be created. This serves to save time and reduces errors when creating new switch plans.

Integration Requirements

The following are basic OMS integration requirements to meet PSE business information needs.

- The OMS is tightly integrated to the CIS and IVR to receive customer trouble calls and to provide customer specific status
- The OMS is integrated to the EMS/SCADA to receive real-time network device status and tags; this is generally a one-way interface
- Interfaced to the GIS to receive electric network data, and to the CIS to receive customer data; this is a bulk data transfer process performed nightly
- Integrated to a meter data management system to receive AMR "last-gasp" loss of power detections and the ability to "ping" specific meters for energized verifications
- The OMS is tightly integrated to the mobile workforce management (MWF) system for dispatch control and to receive field status notifications

Below is a typical integration diagram for an outage management system. PSE may not chose to implement all interfaces at this time.

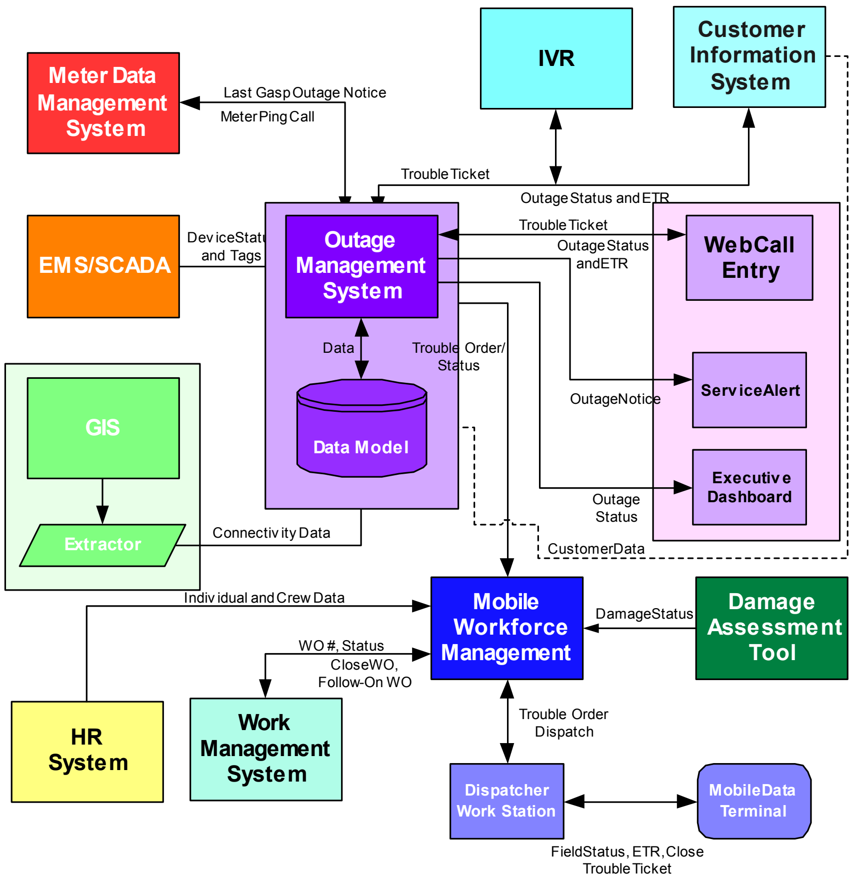


Figure A-3 Outage Management System

Appendix B: Geographic Information Systems

In the broadest sense, Geographic Information System (GIS) is a collection of computer software, hardware, and data used for the capturing, managing, analyzing, and displaying of geographically referenced information. GIS, for an energy utility, provides the functionality and applications to manage and use spatially referenced facility data in a graphic format. The GIS implemented in an energy utility contains two major sets of data, land base and facilities. The land base set includes features of interest to the utility, such as streets, land parcels, and natural areas like rivers and bodies of water. The utility may also include in the land base specific operating features, such as rights of ways and easements, tax and franchise boundaries, environmentally sensitive areas, and physical access information to facilities. The facility set includes the outside plant information for the utility. For gas, this includes pipelines, mains, services, valves, regulation stations and cathodic protection information. For electric, this includes structures, conductors, switches, substations, protective devices and transformers.

The power of the GIS is in its ability to utilize the geographically referenced facility data. The following are some application examples that are built on top of the GIS to take advantage of this data:

Gas:

- Critical valve isolation area and customers affected
- Cathodic protection area, CP Test Point locations and anode configurations
- Main material and coating by segment and area
- Pipeline profile analysis
- Leak survey route planning and leak placements for leak analysis

Electric:

- Conductor length and material type by segment
- Vegetation management planning of corridors
- Location of man holes and underground cable access points
- Duct and conduit layouts
- Structure locations and specific characteristics
- Joint usage pole application

In addition to these GIS applications, the data contained in the GIS is used to enable other software applications. This is because the gas or electric network is defined topographically in the GIS, meaning that it has relationship intelligence and connectivity. This network topology is used to support applications that require this feature. Examples follow.

- ***Distribution Planning System***. The connectivity model in the GIS can be imported by a network analysis software (SynerGEE, Cyme, PSSE/E, etc.) for planning analysis of the gas or electric system. Since the GIS will contain this information, it is not necessary to build this network model in the planning software itself, thus saving time and maintaining the model in one place.
- ***Outage Management System***. The OMS requires the electric distribution network to be able to perform an outage analysis. This network information consists of conductors, the electric phases (A, B, C), protective devices (switches, reclosers, fuses, etc.), transformers, and other devices that impact the electrical characteristic of the system, such as capacitor banks. In addition, if power flow analysis is required, information such as conductor size and material type is also needed. The best place for this information comes from the GIS, which defines the as-built configuration of the electric system. This is placed in the OMS then changed to the as-operated configuration.
- ***Graphical Work Design***. Graphical Work Design (GWD) is a generic term for a software function that interfaces to the GIS for the creation of detailed engineering designs. It generally has full Computer Aided Drafting (CAD) functionality and tools. The advantage of using a GWD software with the GIS is that it uses the existing land base and facilities for the planned design of new facilities and assets. In this manner, when the actual facility is completed in the field, the as-built configuration can be entered into the planned design configuration. The when this information is added to the GIS during the update process, the file will fit spatially correctly because the reference file originated from the GIS.
- ***Operations Map Board***. A high-resolution large screen display generally used in the control center to display single line diagrams of the transmission or distribution circuit. Outage diagrams and information can also be displayed onto the screen. These systems are generally back-lit and have excellent resolution of detail.
- ***Field Mapping and Data Capture***. The GIS information can be used in the field to view maps and records. The field data device (generally a hardened laptop) can also be used to view construction drawings and to especially capture the as constructed configuration and information in the field. In this manner, this as-built information can be sent to the Mapping Department once in the office. Other information such as inspection and maintenance data for field assets can also be captured and uploaded to the GIS or asset management system.
- ***Web GIS.*** The general user of GIS information will most likely access spatial information using Web GIS. In this manner, a user can query, view and output required information.

The GIS, of course, is used to produce standard map products for the utility. This includes facility maps produced in hard copies for map books, electronic maps to take into the field, and web map viewing for query and output. The GIS also supports applications that are land base or geographically references. Some examples are:

- Analysis of rights of ways and easements
- Calculating facilities within franchise boundaries for valuations and taxes due
- Access information to physically access critical facilities like circuit switches
- New facility route and corridor analysis
- Routing optimization for route planning (meter reading, customer service field serviceman routing, leak surveys)
- Environmental impact assessments
- Marketing and new business planning
- Facility site analysis and planning and real estate analysis

The diagram below depicts the GIS in a typical best practice integrated environment.

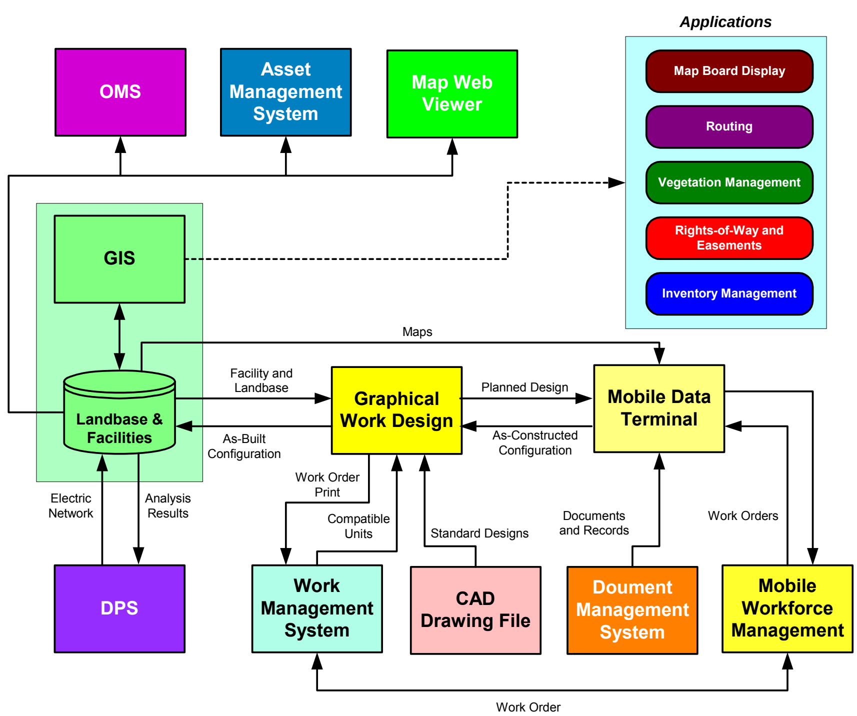


Figure B-1 Best Practice Integrated Environment

Maintaining Data Integrity

Once the map data conversion and cleanup process is completed, effort must be taken to maintain the data in its correct and quality state. Thus, a data integrity program must be instituted. This program is a combination of business processes, roles, responsibilities and tools that help maintain the data. Business processes must be re-engineered to address the need for data timeliness, completeness and correctness. Roles and responsibilities of those along the process thread who are responsible for the capture, recording, maintaining and owning the data are defined clearly. Tools that enable the process include the graphical work design, distribution planning system and field GIS, which were discussed earlier.

The graphical work design software allows a mapping group to readily update the proposed design that has been inputted into the GIS with current as-built information from the field. Since the land and facility source file is the original from the GIS, any updates will readily align and correctly "fit" once the update is committed without any editing. This is a significant time saver and assures data integrity by eliminating a re-drawing step. The continued use of a network analysis software such as SynerGEE will also significantly help to find connectivity and phasing errors in the network. The following diagram is a generic configuration of the graphical work design and planning software in place.

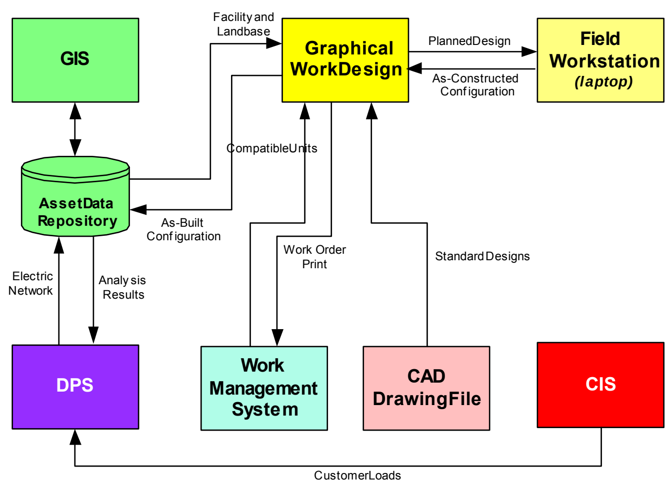


Figure B-2 Geographical Work Design and Planning Software

At PSE, the Mapping and Records Department is testing, under a pilot program, the functionality and usability of the AutoDesk Utility Designer (AUD) software. AUD is a graphical work design software that can work with a GIS and other CAD files like AutoCAD.

Implementing the correct tools along the data create, edit, update and record processes, along with proper process re-engineering, will significantly help to maintain data integrity and quality.

EXHIBIT K

Enterprise GIS

Leadership Team Presentation

Puget Sound Energy

Needs & Requirements Assessment of Enterprise GIS

NOT FOR CIRCULATION

HIGHLY CONFIDENTIAL

May 28, 2008

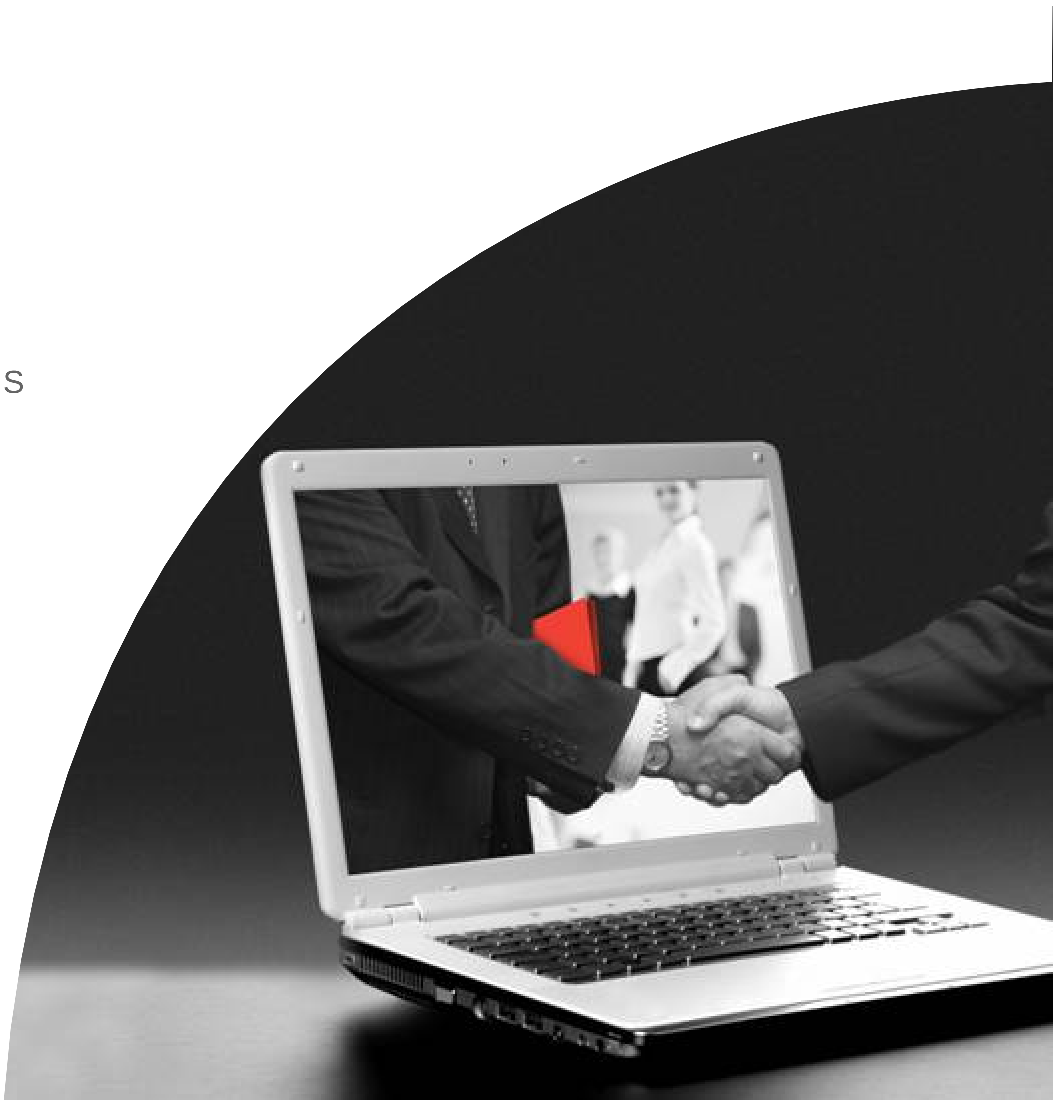


Table of Contents

PA Consulting Group

PA Consulting Group (PA) was engaged to help assess PSE's needs and requirements for an Enterprise GIS…

As a result of a major storm in 2006 PSE engaged a 3rd party to complete a detailed review of its outage processes including a cost/benefit analysis for the implementation of an Outage Management System (OMS) and a supporting GIS implementation

In reviewing the 3rd party analysis, PSE recognized that a number of other business units are, or are considering, pursuing the use of a Geographic Information System (GIS)

PSE sought a third party high level assessment of its enterprise-wide GIS needs, its current approach to the use of geospatial data and recommendations on potential benefits and implementation strategies for GIS.

This report presents the results of a 4 week study that qualitatively assessed the needs & requirements for Enterprise GIS

PA utilized a Program Blueprint framework in order to rapidly assess the needs & requirements for Enterprise GIS…

Phase I: Week 1-4

Discovery → Interviews → Workshops → Report

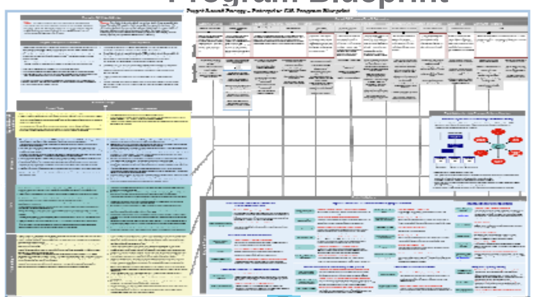
Phase II: Week 5-10

Budget → Org Design → ROI

In Scope | Out of Scope

Key Deliverables

Program Blueprint



Implementation Options

Multi-year Capex / Opex Enterprise GIS Budget

ROI-based Benefits Modeling

Characteristics

- Business-led, not technology-led
- Benefits-focused, not functionality focused
- Fact-based
- Highly participative with involvement from a wide cross-section of the business

PA Consulting Group

The following PSE staff were engaged through interviews and workshops to solicit their insights, needs and requirements for Enterprise GIS…

Interviews

Operations						General Counsel	Power Generation	Energy Efficiency	Finance	Corporate Affairs	
Operations	System Planning	Customer Service	IT	Compliance & Safety	Street Lighting	Environmental	Asset Services	Marketing Strategies	Accounting	Community Services	Facilities
Sue McLain (SVP) **Greg Zeller** (Dir. Electric Operations) **Harry Shapiro** (Dir. Gas Operations) **Jan Senk** (Dir. Customer Construction) **Beth Rogers** (Vegetation Management)	**Jennifer Tada** (Dir. System Planning) **Stephanie Kreshell** (PM Distribution Integrity Management)	**Janet Gains** (Dir. Customer Services)	**Todd House** (Dir. Application Services) **Bob Collins** (Dir. Infrastructure) **Charles Seese** (Mgr. Telco Services) **John McClaine** (Meter Data Warehouse)	**Duane Henderson** (Dir. Eng. & Ops. Services)	**Paul Kinberg** (Maintenance Supervisor) **Ray Harris** (Maintenance Program Coordinator)	**John Rork** (Mgr. Environmental)	**Kris Olin** (Mgr. Plant Technical Services) **Ramiro Silva** Snr. Eng Specialist	**Bill Hopkins** (Mgr. Strategic Planning & Research)	**Mike Stranik** (Assistant Controller) **John Story** (Dir. Cost of Service & Revenue Requirement)	**Jason Van Nort** (Community Relations Mgr.)	**Brett Bolton** (Mgr. Real Estate) **Ron Bott** (Mgr. Right of Ways)

Core Team

Bert Valdman	**Sue McLain**
Booga Gilbertson (Sponsor)	
John Phillips (PM)	
Bob Bischoff, Mark Maass, Mark Wesolowski, Phil Prentiss, Shaun McMullin, Roger Fletcher, Todd House	

Core team was formed to provide overall guidance on the engagement

Workshops

- **Core Team Discover Workshop**
- **Data Migration Workshop**
- **Data Management & Workflow Workshop**
- **IT/ Technology Workshop**
- **Core Team Review Workshop**

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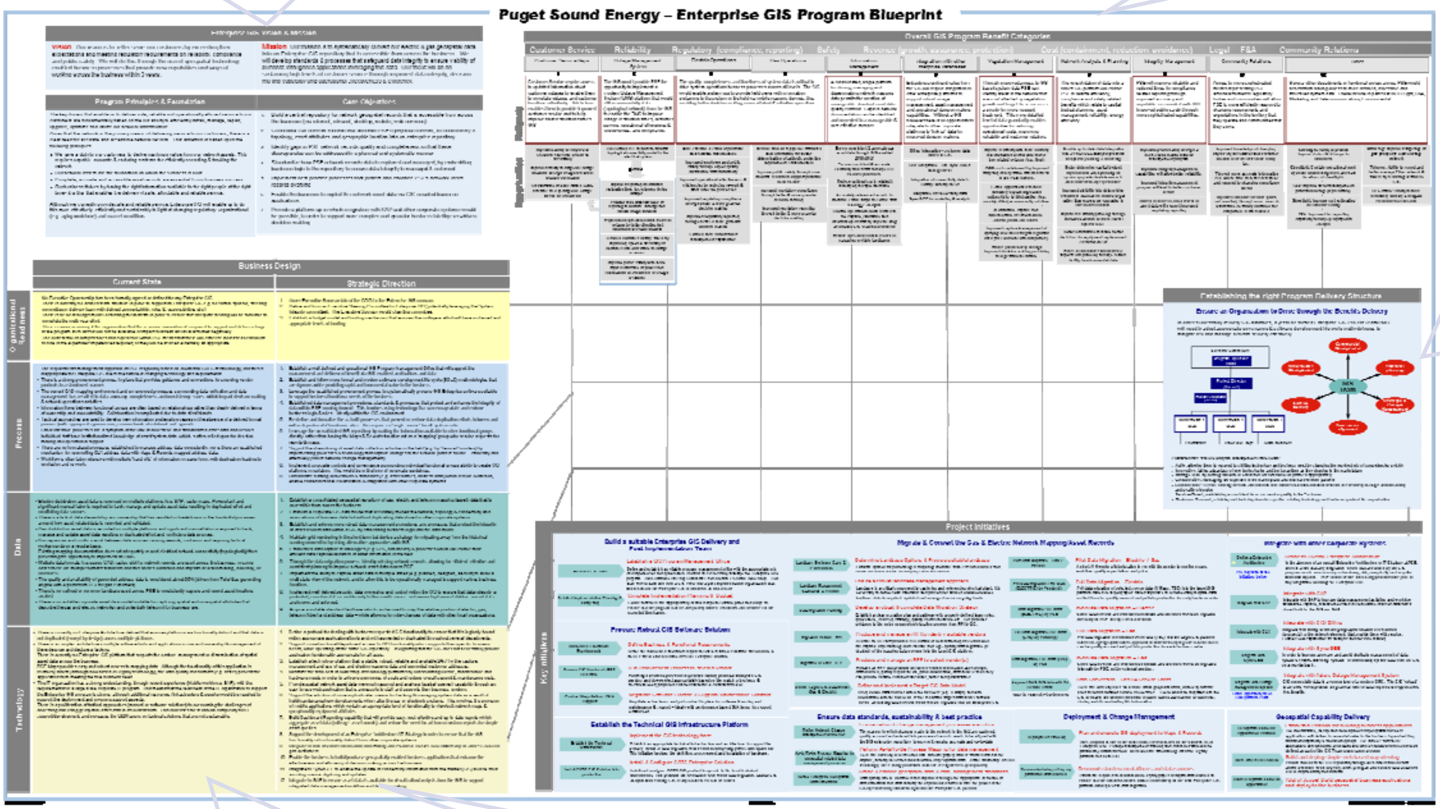
The results of the study are encapsulated into the GIS Program Blueprint, which articulates the business benefits and Program initiatives

Vision, Mission, Program Principles and Core Objectives

Needs & Requirements represented as business benefit opportunities

Poster Size – Program Blueprint



Program governance & management oversight recommended for successful delivery

Summary of the business design current state (data, technology, processes & organization)

Summary of the business design desired state (data, technology, processes & organization)

Discrete initiatives (projects) required to realize the business benefits/opportunities sought

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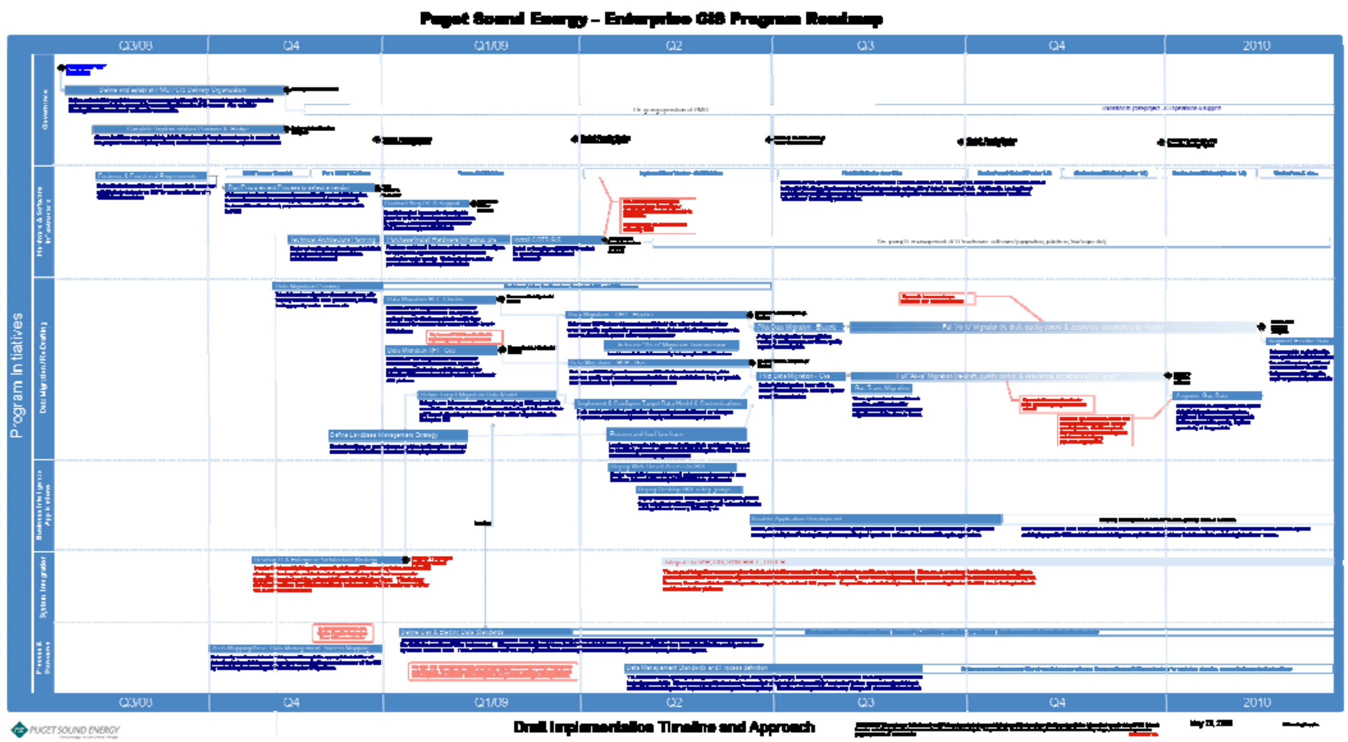
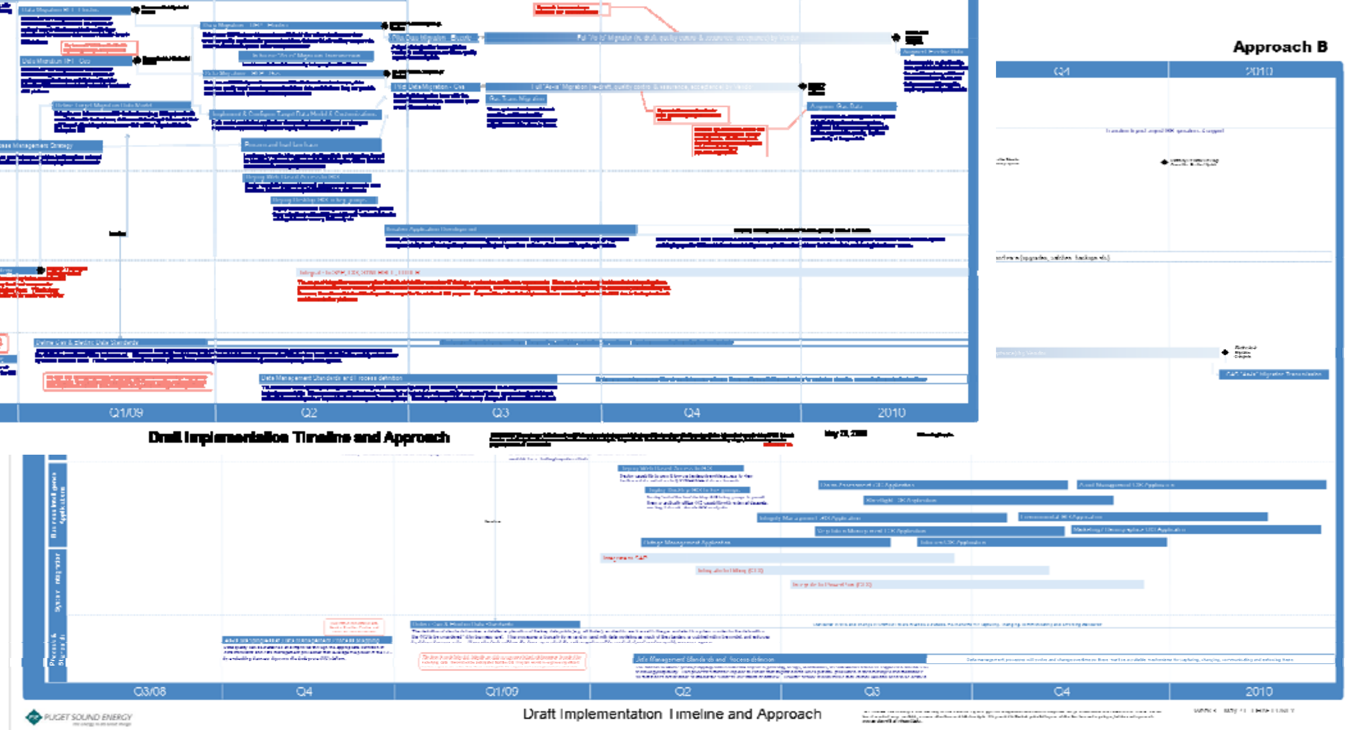
The Enterprise GIS Program roadmap provides a clear path to realizing the expected and required business benefits…





Several options for execution were discussed, and two potential roadmaps assembled

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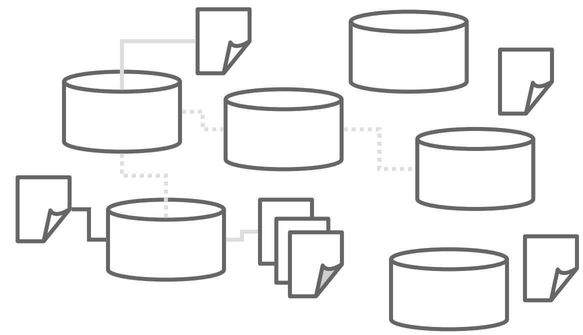
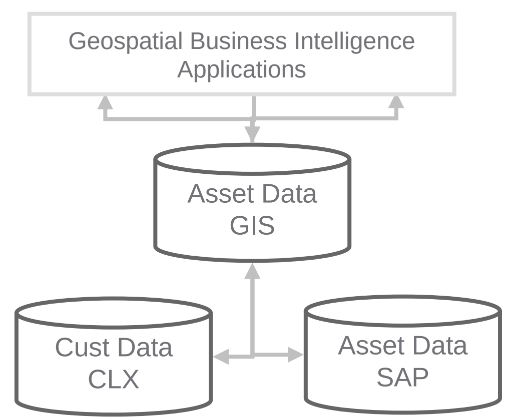
This study confirmed that there is an enterprise-wide need for more granular and accessible geospatial data and analytical capability…

- **Manual & labor intensive processes abound**
  - There was consensus from across the business that the existing manual & labor intensive processes that support the capture, maintenance, dissemination and use of geospatial asset data for operational & strategic decision making are unsustainable
- **Proliferation of 'home grown' tools has led to complexity**
  - There has been a proliferation of 'home grown' tools, work-arounds and manual interventions across PSE as a result of the historical manual approach to recording asset location, condition, descriptive and connectivity data
  - Rudimentary silo'd pockets of geospatial capability already exist within PSE, although these are tactical in nature and duplicate effort, cost and limit opportunities for data sharing & cross-functional collaboration
- **Duplication of asset data stored in multiple places & formats causes confusion**
  - Asset data is duplicated in multiple platforms/sources and is known to conflict. This leads to confusion, re-work and manual interventions.
- **Limited awareness of data stewardship or ownership impacts data integrity**
  - Perception amongst PSE staff is that there is not a consistent strong culture of data stewardship, information management or data ownership. This compounds the challenge of capturing & maintaining accurate asset data.



Current Situation



Desired Situation

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The capabilities sought by those interviewed point to a fundamental need for access to quality asset data, not overly complex GIS functionality…

Operations						Power Generation	Energy Efficiency	Finance	Corporate Affairs	
Operations	System Planning	Customer Service	IT	Compliance & Safety	Street Lighting	Asset Services	Marketing Strategies	Accounting	Community Services	Facilities

Over 35 individual business benefits relating to these categories were identified

Core benefit areas…	Secondary benefits areas…
Customer Service (Reliability)	Cost Containment, Avoidance & Reduction
Compliance & Regulatory Reporting	Revenue Growth & Assurance
Public Safety	Tax Reporting & Compliance
	Community Relations

Note: Benefits were not modeled or quantified during the initial 4 week study, they were captured from qualitative statements made during PSE interviews

In response to this core requirement, we reached consensus on the following foundational Enterprise GIS Program Objectives…

The Enterprise GIS Program must focus on getting the fundamentals right first; not on overly complex business applications

Foundational Enterprise GIS Objectives…

- Build a central repository for network geospatial records that is accessible from across the business (via internet, intranet, desktop, mobile, web services)
- Consolidate all network records that describe PSE's physical network, its connectivity & topology, asset attributes and geographic location into an enterprise repository
- Identify gaps in PSE network records quality and completeness so that these discrepancies can be addressed in a planned and systematic manner
- Standardize how PSE network records data is captured and managed, by embedding business logic in the repository to ensure data integrity is managed & enforced
- Implement best practice processes that protect and enhance PSE's network asset records over time

Leveraging the Enterprise GIS foundation for wide-spread business benefit…

- Enable the business to exploit the network asset data via GIS-enabled business applications
- Provide a platform upon which integration with SAP and other corporate systems would be possible, in order to support more complex and granular business intelligence-driven decision making.

Based on these Objectives, we constructed an appropriate Program of work that will enable PSE to realize the desired benefits…

- **Establish a GIS Program Management Office (PMO)**
  - A suitable Program delivery organization must first be established to ensure that appropriate governance is in place to manage and control the Enterprise GIS Program and subsequent on-going operation
- **Procure and install an Enterprise grade GIS solution**
  - Select and negotiate a suitable software license, maintenance and support contract with a GIS vendor through a structured procurement process
  - Design a technical architecture appropriate for an Enterprise grade GIS solution; procure the hardware; install and configure
- **Re-design key processes pertaining to data collection and management**
  - Map and analyze the as-is data management processes for planning→ design → as-built processes; determine if outsourcing the end-to-end process to the infrastructure Service Provider (or other 3rd party) is commercially, culturally and technically feasible
  - Design appropriate to-be processes and establish strong data management (stewardship, ownership and quality assurance & control)
- **Re-draft the Electric and Gas network assets onto a common landbase**
  - Acquire a common landbase; re-draft both electric and gas assets onto the new landbase using off-shore resources "as-is" ; identify & record data gaps/omissions within the data during re-draft to address post-migration.
- **Integrate to other Corporate Systems**
  - Integrating to other Corporate Platforms such as SAP and CIS would enable more comprehensive management of asset data and reduce re-work, duplication of data and silo'd functionality
  - Integration to an OMS would potentially provide PSE with additional opportunities for improving reliability, customer service, compliance and public safety

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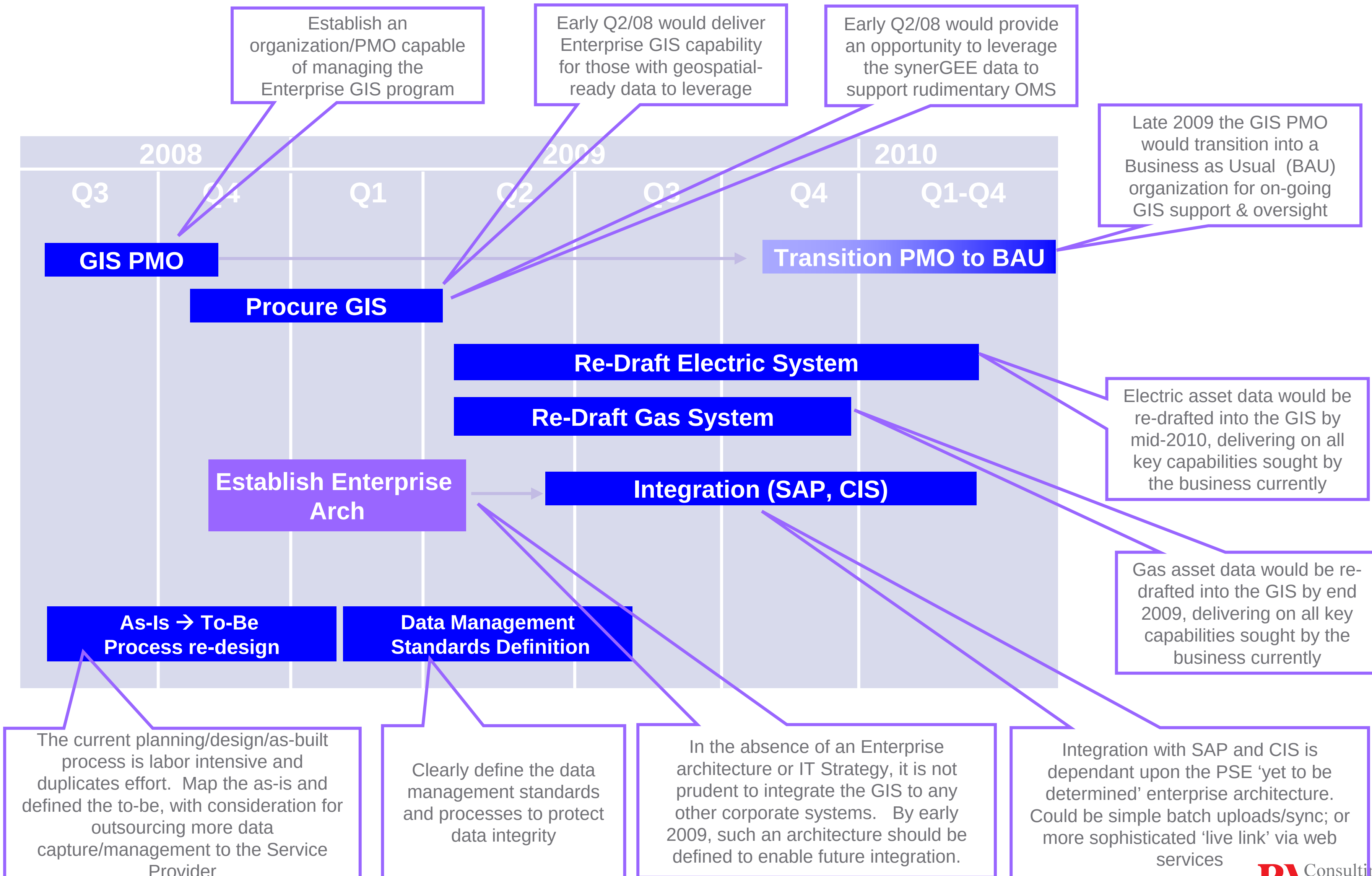
We outlined a potential implementation timeline based on the key benefits being sought by the business…



We prepared preliminary budget estimates based on the timeline and previous experience with these types of GIS implementations...

- Preliminary indicative budget estimates to procure, implement, re-draft (electric & gas) and re-design key processes to be approximately [redacted]
- Capital and operational (O&M) allocations have not yet been defined
- Cost will be impacted by strategic decisions relating to the execution approach, levels of outsourcing used for re-drafting, GIS technology platform chosen, PSE resource availability etc.
- The cost estimate does not include the design, development and deployment of sophisticated GIS-based business applications. Typically, these are low-cost and funded by individual business units/groups
- The majority of the cost is encapsulated in the Enterprise GIS infrastructure and data migration effort

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We recommend a full capital / operational budgeting analysis be performed to determine more refined budget estimates

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Key Recommendations

- Design & stand-up an appropriate GIS Program Management Office (PMO) with strong Executive support via a cross-functional Steering Committee led by the COO
- Build a detailed capex / opex budget forecast that clearly defines the total cost to procure and own/operate the Enterprise GIS (this study was purely qualitative)
- Consider if a return on investment analysis is required in ensure successful outcomes; and to ensure defensible metrics are available for rate case & regulatory discussions
- Determine if 3rd parties could more cost-effectively manage the end-to-end planning-design-as-built (& planned/emergency maintenance) data capture processes for both electric and gas; establish clear SLA-based contracts which account for quality and data integrity
- Procure and implement an Enterprise GIS solution
- Re-draft the Electric and Gas geospatial network asset data into the GIS solution so it is accessible from across PSE. Focus on as-is re-drafting, not on fixing the asset data during re-drafting processes; this should occur post re-draft when more systematic data quality improvement initiatives can be designed and executed
- Focus the implementation team on key *foundational* requirements (hardware, software, data conversion, data standards/management processes)
- Do not over-commit to the business to building geospatial business intelligence aspects for the business…these will evolve as the foundation matures
- Investigate the opportunity/feasibility of running an Outage Management System program of work in parallel with the GIS program, thus capitalizing on the synerGEE connectivity data in early Q2/09.

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Next Steps

We recommend the following next steps:

- Communicate the results of this study and the strategic intent/direction of the Enterprise GIS program to the business
- Design an appropriate GIS PMO, combining a mix of internal and external competencies/capabilities/SMEs to support the successful delivery of the Program
- Develop a robust and detailed capital & operational multi-year budget to capture the complete expected costs of implementing and operating the Enterprise GIS
- Complete a detailed implementation plan (90 and 180 day plans) that is adequately resourced and funded to ensure the GIS program launches successfully
- Investigate the opportunity to leverage the competencies/capabilities of 3rd parties to re-engineer the data capture and management efforts around planning, design, as-builts in particular.

EXHIBIT L

Logistics RFP Requirement Document

PUGET SOUND ENERGY

Address Invoices To:
Puget Sound Energy
Accounts Payable Dept.
PO Box 90868 - PSE - 10S
Bellevue, WA 98009-0868

Direct All Inquiries To:
Puget Sound Energy
Purchasing Department
PO Box 90868 - PSE - 10N
Bellevue, WA 98009-0868

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Outline Agreement - 4600005035

Seller
126136

BASE LOGISTICS LLC
3809 DAY ST
HARVEY, LA 70058-2352

Seller Phone
504-734-1204

Seller Fax
1-504-733-6531

Your Quotation No.

Date

Confirming To
R. Young

Confirming Date
6-10-08

Outline Agreement No.
4600005035

Date
06/10/2008

Contact Person
F.C. Leyritz / 102

Phone
425 462-3350

Fax
425 462-3214

Validity From
06/10/2008

Validity to
06/10/2009

Delivery Terms
FOB Destination (FOB): PSE LOCATION

Shipping Point

Ship Via

Payment Terms
Within 30 days Due net

Seller to include "material safety data sheet" (MSDS) with packing papers if any of the items purchased include chemicals or hazardous substances that are a factor in their disposal. Chemicals and hazardous substances include, but are not limited to: chlorofluorocarbons (CFC's), paints, solvents, oils, compressed gasses, batteries, janitorial products and office products such as corrections fluid and toner, etc.

The following pertains to all line items

Item	*Service ID*	*Description*	*Unit Price*	*Unit*
00010		**Base Logistics - LA Plan development**		

This item covers the following services:

Requirements for Base Logistics, LLC to develop and deliver to Puget Sound Energy a Local Area Emergency Response Staging Plan.
Agreement for Professional Services No: 4600005035

Customer: Puget Sound Energy, Bellevue, Washington (hereinafter referred to as PSE),

1.0 Scope of Work

1.1 Base Logistics, LLC (hereinafter referred to as Base), to produce and deliver to PSE a written Plan for a Local Area Emergency Response Staging Plan (hereinafter referred to as the "Plan") in

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USA

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accordance with PSE's Corporate Emergency Response Plan that establishes processes and identifies resources and services required to support internal and Mutual Assistance personnel (both PSE employees and PSE contracted personnel) involved in restoration operations. Identify logistics roles and responsibilities; establish parameters for resource activation and event management (all to be documented within the Plan).

REDACTED

1.1.1 Total time for Base to complete the Plan, starting from Work Scope (contract) acceptance by Base, through to final completion, and delivery to PSE of the written Plan would be 45 - 70 days after acceptance by Base of this Work Scope.

1.1.2 Total Cost would be [redacted] Remittance to Base would be Net 30 (i.e. 30 days after PSE's receipt of the Plan); assuming the Plan will be acceptable to PSE as required in the Work Scope.

1.1.3 To finalize and produce the Plan Base would send to PSE's service territory 2 (two) logistics managers/specialists and 1 (one) catering managers/specialists. Base management staff would also be sent to PSE's territory for approx. 3 to 5 days to conduct a draft plan evaluation with PSE's staff.

The above Schedule of Performance (hereafter referred to as the Schedule) would be preceded by a Base/PSE conference call within four working days of Base's acceptance of this Work Scope to finalize Base's trip to PSE and the Schedule.

1.1.4 Base will submit to PSE a timetable three to four weeks prior to sending their employees to PSE's service territory to enable PSE to schedule the appropriate PSE employees. Base will also submit within this timeframe a proposed list of questions, requests for data, maps, contact persons, PSE job titles/positions to be interviewed, etc.

1.1.5 Schedule Summary:

> Four working days of Base's acceptance of this Work Scope conduct Base/PSE conference call to finalize Base's trip to PSE and the Schedule.

> Three to four weeks prior to Base sending their employees to PSE's service territory Base to provide a timetable to PSE.

> 45 - 70 days after acceptance by Base of this Work Scope Base will complete and deliver the Plan to PSE.

> Net 30 remittance to Base by PSE upon receipt of acceptable Plan.

1.1.6 PSE will have intellectual ownership of the Plan to utilize as needed.

1.2 Develop and document a qualified vendor network capable of responding to PSE's needs in for emergency outage/recovery events Incorporate (as appropriate) a listing of present PSE qualified vendors to be integrated into Base's network. Base will publish the vendor network as part of Plan. Each product/service category will be ranked within Base's vendor network document and have sufficient backup vendors documented.

1.3 Develop and document 5 (five) unique site specific standard footprint plans for PSE's regional staging sites and one (1) Local Area Coordination (LAC) standard footprint, all applicable to each site's characteristics.

2.0 Development Summary

Base will develop a logistics plan in accordance with the emergency response requirements and procedures established in PSE's Corporate Emergency Response Plan. Processes for activation, including timelines and event management, will be established and documented specific to PSE's Corporate Emergency Response Plan. The Plan will be designed to allow PSE to scale Base's participation as necessary to meet individual event requirements.

As part of the Plan, Base will develop a vendor network capable of providing the services and/or products necessary to support personnel working an outage/recovery event. The network will include local and regional vendors capable of providing any and all of the services and/or resources delineated and documented within the Plan.

Where feasible, Base will adapt processes and utilize vendors that have proven capable in previous response situations for Base and determined to be able to perform within PSE's service territory. This will allow for efficient and cost effective implementation. The service and product provider network will be developed using Base's parameters as to capability, location and responsiveness.

The services and resources included in the Plan will include staging site layout/design, on-site catering, laundry service, fueling, security, sanitation facilities, alternative housing, and site resources to complete staging site and local area coordination site functionality for emergency events.

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2.1 Development of the Plan will include but not be limited to:

2.1.1 Being similar in scope to the "Generic Plan.doc" previously sent to PSE.

2.1.2 Qualification of vendors (including to be able perform within PSE's service territory).

2.1.3 Interview designated PSE staff with Emergency Response knowledge/responsibilities, e.g. EOC management/staff, stakeholders that would utilize/staff local area sites.

2.1.4 Planned time frame and length for Base to conduct fact finding within PSE's service territory would be approx ~~6/23/08~~ through ~~6/27/08~~ taking approx. 3.5 days in PSE's service territory. TBD [initials] 6/12/08

2.2 Staging Site layout/design will include:

2.2.1 On-site inspection by Base logistics personnel to help PSE determine best design to maximize site utilization. PSE will provide escorts as needed to accompany Base employees.

2.2.2 Site drawings to illustrate locations of site resources, fleet parking configuration, and material lay-down areas

2.3 Development of foodservice resources will include:

2.3.1 On-site, full-service catering units

2.3.2 Foodservice suppliers

2.3.3 Bottled water, ice, sodas, snacks

2.3.4 Tents, tables and chairs

2.3.5 Fans or Heaters

2.3.6 Refrigerated storage equipment for food supply and ice

2.4 Fueling

2.4.1 Staging site wet-hose fueling operations

2.5 Laundry Service

2.5.1 Develop a geographic network of laundry facilities capable of meeting restoration requirement

2.5.2 Develop reliable mobile laundry unit resource

2.6 Staging site resources

2.6.1 Mobile Incident Command Unit, mobile office units (Mobile Incident Command Unit would be the most complex, i.e. a mobile/temporary office approx. 5- 6 desks, small meeting area, lighting, HVAC, generator support during occupancy, etc.). (Mobile office unit would be primarily for only emergency personnel/crew briefings/meetings).

2.6.2 Portable restrooms, trash bins

2.6.2.1 Including black water and waste disposal

2.6.3 Portable lighting (tower lights) & generators

2.6.4 Storage/cover tents for on-site materials

2.6.5 Potable water supply when required

2.6.6 24 hour armed or unarmed Security Service

2.7 Alternative Housing Resources

2.7.1 Sleep Tents

2.7.2 Bunk Trailers

2.7.3 Ablution Facilities

2.7.3.1 Mobile showers (including potable water gray black water retention/disposal units),

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portable restrooms, etc.

2.8 The Plan will include an assessment by Base of the roles and responsibilities of how many PSE employees would be needed to interface with Base before/during/after the event, to be assigned to each LAC site (i.e. PSE site representative), to coordinate all major activities that could impact timeframe, costs, site access, etc. Examples of coordination could be PSE providing Base with needed data/information/contacts, significant plan revisions, approve substitutions, authorize change orders, etc.

3.0 Plan Maintenance

REDACTED

3.1 Base will manage retention of the vendor network to ensure response capabilities.

3.2 Vendor information will be updated and published in the Plan on an annual basis. All updates will be completed and made available to PSE prior to November 1 of subsequent year.

The maintenance fee each year to update the plan would be [redacted]

3.3 Base will be available to participate in mock storm drills as requested by PSE for table top/conference call discussions. This would be no cost to PSE.

4.0 Event Response (Base's actual Event Response and resulting costs would be detailed in a separate Master Service Agreement (i.e. blanket contract).

Base will provide trained personnel to manage logistics resources deployed for an outage event.

4.1 Base Incident Command Team will secure and dispatch required resources as directed by PSE.

4.1.1 Provide management/supervisor level communications link to PSE's Emergency Operations Center (EOC).

4.1.2 Assign individual Base logistics support personnel assigned to specific PSE requirements.

4.1.3 Support deployed Base logistics managers and personnel throughout the event.

4.2 Base managers and support personnel will be deployed to the affected areas immediately to supervise staging site set-up, ensure that required resources are secured and to interface with PSE personnel on-site.

4.2.1 Site personnel include:

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4.2.1.1 Site Logistics Manger(s)

4.2.1.2 Logistics Support Personnel

4.2.1.3 Logistics Supply Chain Personnel

4.3 Base will develop the Plan so as to minimize the number of PSE's personnel involved in the details of carrying out the activated Plan (see section 2.8 above) from the time of the initial call for Base to begin deployment through to completion.

4.4 If PSE requests Base to activate the Plan, within the Plan will be a provision to provide PSE with a daily e-mail progress reports that documents all the major milestones such as:

Dates for: requested vendor equipment/supplies, Base personnel are leaving for travel to PSE's service territory, etc.

Daily reports of in-transit location (for the above) and updated ETA from the beginning from the first call PSE places to activate the Plan until arrival.

Base will conduct post-event critiques involving self-review and feedback from PSE and other involved parties. The results of such critiques will be incorporated in future strategies. Additionally, Base will be available to participate in post-event critiques as designated by PSE at no extra cost. This clause would be incorporated into any resulting Master Service Agreement.

The above described Work Scope constitutes the entire agreement between buyer and seller (including Puget Sound Energy's General Terms and Conditions) and any changes are to be authorized only by written change order to the original purchase contract issued by the buyer or authorized person from the PSE purchasing department.

ACCEPTANCE OF THE ABOVE WORK SCOPE:

For the Buyer

C.P.M.

(Signature)

Frank C. Leyritz, C.P.M.
Consulting Buyer/Process Leader
Puget Sound Energy

Date 6/10/08

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EXHIBIT M

Potential System Hardening Strategies

SYSTEM HARDENING STRATEGIES*

* *System Hardening strategy list result from a brainstorming session with members from Electric First Response, Standards, Engineering and Total Engineering System Planning with the objective of identifying strategies that should be implemented to harden the T&D system to withstand storm outages.*

Strategies	Issues	Solution	Benefits	Cost Assumption	Capital Cost	O&M Cost
Improve Fuse Coordination	Distribution System fuse coordination is being compromised by NCC projects that don't upgrade fuses at the time of new installations. Service Provider to look upstream of the new construction project and re coordinate all fuses back to the feeder	Have someone review maps in areas where known miscoordination exists and have maps changed to reflect the correct fuse size we want at each location. The resul would be that when servicemen replace a blown fuse they can look at the map to get the correct size; mapping and TESP are working on a plan to implement this solution.	Help limit the outage to minimal customers. Reduce serviceman patrol time to allow them to move on to other things.	Hire student intern at cost of $20/hour for 3 months to review maps	$ -	$ 9,600
Engineering Design Practice	When feasible install newly constructed overhead lines on the side of a street that is opposite the prevailing storm winds. In most of PSE's territory the storm winds come from the south or west. In some parts of Whatcom County they come from the north. In canyon areas like North Bend and Enumclaw they come from the east.	Incorporate in next version of Engineering Design Manual	Less OH line outages due to wind.	No cost	$ -	$ -
Circuit Segmentation	Double deadend distribution lines on either side of heavily treed areas that are know to result in outages. Install switches to help isolate the outage to the smallest numbe of customers.	Install switches on primary feeder to help isolate the outage to the smallest number of customers; this solution will be turned over to TESP to apply as part of planning process	Help limit the outage to minimal customers.	Average cost of $7.5K per switch location for 2 locations in 1,032 feeder circuit compywide	$ 15,480,000	1,548,000
Construction Practices	Cascading transmission structural failures	Double deadend transmission lines on either side of heavily treed areas to prevent cascading structure failure requiring the changing out the poles; this solution will be turned over to Engineering to implement.	Help limit the outage to minimal customers.	Average cost of $15K per location; assume 100 locations companywide	$ 1,500,000	150,000.0
Construction Practices	In areas that are heavily treed reduce the frequency of damaged transmission conductors falling into a busy road.	Change transmission vertical turns to double deadends without changing the poles; this solution will be turned over to TESP to apply as part of planning process	Help limit the outage to minimal customers.	Average cost of $15K per location; assume 50 locations companywide	$ -	$ 750,000
Circuit Segmentation	Sectionalizing of damage distribution lines	Install more solid blade cutouts on primary laterals between fuses to allow sectionalizing of damaged distribution lines to reduce the number of customers that remain out from damage; this solution will be turned over to TESP to apply as part of planning process.	Help reduce outage time for customers.	Average cost of $3K per location; assume 4 locations per circuit for 1,032 circuit companywide.	$ 12,384,000	$ -
Switching Scheme	Evaluate transmission automatic switching schemes for impact of momentary outages on substations. Add more circuit breakers to eliminate some of these outages.	Being done as part of transmission planning process; this solution will be turned over to TESP to apply as part of planning process.	Help reduce outage time for customers.	No cost	$ -	$ -

SYSTEM HARDENING STRATEGIES*

* *System Hardening strategy list result from a brainstorming session with members from Electric First Response, Standards, Engineering and Total Engineering System Planning with the objective of identifying strategies that should be implemented to harden the T&D system to withstand storm outages.*

Strategies	Issues	Solution	Benefits	Cost Assumption	Capital Cost	O&M Cost
Planning Practice	For the transmission system make it a policy to design the protection scheme so that when transmission lines are looped, no substations are out for a single transmission line fault.	Being done as part of transmission planning process.	Help reduce outage time for customers.	No cost	$ -	$ -
Engineering Design Practice	Discourage the use of distribution compact spacing in heavily treed areas. The close spacing of the conductors catches more limbs and results in more outages when trees are present.	Incorporate in next version of Engineering Design Manual	Help reduce outages.	No cost	$ -	$ -
Construction Practices	Strengthen the"weak link" on our T&D system	Look into the "weak link" concept for both transmission and distribution lines; a consultant will need to be hired to review this concept.	Help reduce outages.	To be reviewed by a consultant	$ -	$ 100,000
Instrastructure Location	Location of transmission poles	Labelling of cross-country transmission line poles where they cross roads. (See Std 0201.0300 on the Standards Dept webpage. It has been updated to include marking requirements.) Make line designations more visible for helicopter patrol; TESP will pursue this solution.	Help reduce outage time for customers.	In a study by Wayne Harris, it was determined that it will cost about $30 to label a pole. Assume that 25% of the 32,000 transmission poles in the company will need to be labelled.	$ -	$ 240,000
Automate Temporary Fault Clearance on single phase lateral	Temporary faults on single phase laterals cause fuse cutouts to operate requiring serviceman to replace fuse. This lead to a 1 to 3 hours outage for the customers.	Replace single phase cutouts with S&C fuse tripsaver which operates like a single phase recloser; this solution is being tested by TESP and Standards.	Temporary faults will not interrupt service to customers.	Cost for the device is about $1,500 per device. We will be trying out the device on 12 laterals in 2008	$ 19,000.00	$ -
Improve Maps	Transmission maps	Make better geographic transmission maps.	Help reduce outage time for customers. Reduce serviceman patrol time to allow them to move on to other things.	Mark Mass to provide new map books to EFR. Maps are arriving at this time.	0	0
		TOTAL COST			**$ 29,383,000**	**$ 2,797,600**

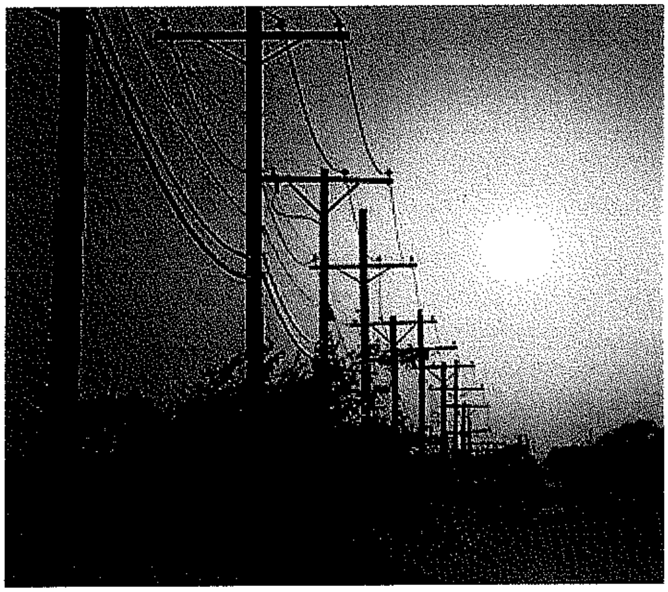
EXHIBIT N

Reliability Roadmap

QUANTA TECHNOLOGY

Reliability Improvement Roadmap

FINAL REPORT



Prepared for: **Puget Sound Energy**

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June 24th 2008

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Executive Summary

Quanta Technology has developed a high level reliability roadmap for Puget Sound Energy (PSE), and estimates a cost of $83,077,000, spread over ten years, for implementation of this roadmap. This roadmap also calls for an increase in the PSE storm hardening budget of $75,431,000, driven mostly by a wood pole test-and-treat program and additional tree removal efforts. The result is a net incremental spending increase of $158,508,000 or about $15.9 million per year over ten years, not including inflation.

It is estimated that this spending will result in an overall system SAIDI reduction of 50%, with significant reliability improvements achieved in each county (see Appendix C for a definition of SAIDI and other reliability indices) This will place PSE in the top quartile of reliability performance for U.S. utilities. These estimates are based on a detailed predictive reliability model of a pilot area and extrapolation based on individual feeders characteristics.

Reliability Targets

Reliability targets are based on system SAIDI using the IEEE 2.5 Beta method for storm exclusion. Tentative SAIDI reduction targets have been set for each county based on customer density. A survey of SAIDI versus customer density has been performed and reliability targets have been set equal to the borderline between 1st and 2nd quartile performance. Current reliability is based on average SAIDI values for 2005-2007. Graphical results of this survey are shown in Figure A. The line labeled "75%" indicates the borderline between 1st and 2nd quartile performance.

An additional 25% reduction has been included to compensate for expected increases in SAIDI when a new outage management system (OMS) is deployed. Reliability targets are shown in Table A.

Pilot Area Model

A predictive reliability model ("model") for an area in Northern King County has been developed in SynerGEE This area serves about 36,000 customers and consists of 30 feeders. This model is able to quantify the benefits of potential reliability improvement projects – both individual projects and sets of projects.

The model has been used to compute cost-versus-reliability curves for a variety of potential reliability improvement options. It has also been used to develop an "integrated solution" consisting of a coordinated mix of projects The combination of these two sets of results is the basis for benefit predictions for the system-wide reliability roadmap. Typically cost effectiveness is measured by the ratio of cost to reduction in customer interruption minutes ($/CMI).

The characteristics of the pilot area are significantly different than the characteristics of certain counties. Therefore, assumptions have been made to account for these differences when developing the roadmap.

Table A. Reliability Reduction Targets

County	Customers (2007 Avg.)	Customer per Square Mile	IEEE SAIDI (min/yr) '05-'07 Average	IEEE SAIDI (min/yr) 2012 Target	IEEE SAIDI (min/yr) 2017 Target	SAIDI Reduction 2012	SAIDI Reduction 2017
Whatcom	93,636	167	125.7	107.3	88.8	14.7%	29.3%
Skagit	56,453	116	149.5	122.1	94.7	18.3%	36.7%
Island	34,308	203	149.7	117.7	85.7	21.4%	42.7%
Jefferson	17,169	85	365.4	232.5	99.6	36.4%	72.7%
Kitsap	113,326	308	255.5	167.3	79.1	34.5%	69.0%
King	511,947	572	115.1	92.2	69.3	19.9%	39.8%
Kittitas	11,304	29	172.8	144.7	116.6	16.3%	32.5%
Pierce	98,443	244	99.1	90.9	82.8	8.2%	16.4%
Thurston	116,787	223	170.2	127.2	84.2	25.3%	50.5%
System	1,053,373	264	143.4	110.7	77.9	22.8%	45.7%

Notes

1. SAIDI and SAIFI are per IEEE 1366 and all counties exclude the same major event days
2. 2017 SAIDI targets achieve 1st quartile reliability normalized by customer density and compensated for OMS effects
3. 2012 targets are halfway between 2007 results and 2017 targets

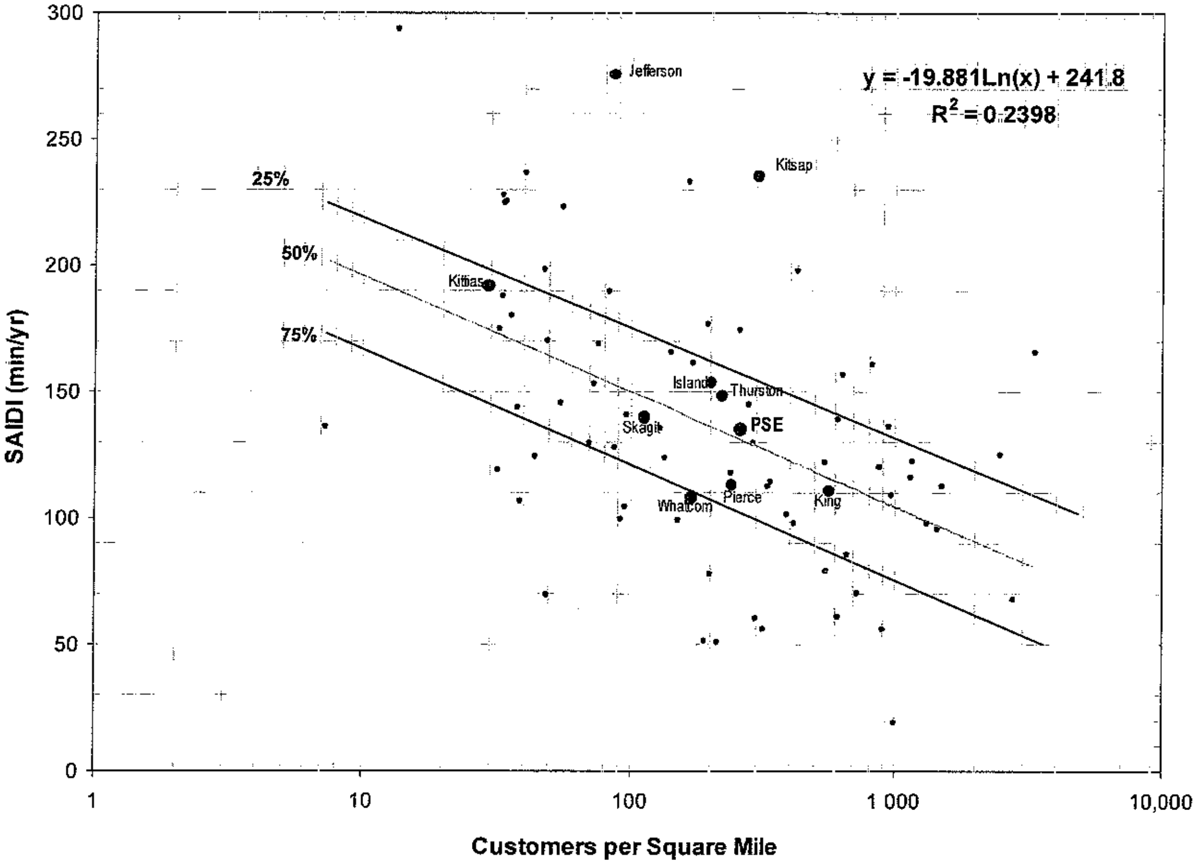

Figure A. Reliabilty vs. Customer Density and Existing PSE County Reliability

Project Interaction Effects

The costs and benefits of reliability projects were often times examined in isolation without considering other projects When multiple reliability projects are performed together, the benefits of the integrated solution are typically lower than the sum of the project benefits considered separately Consider a feeder with a SAIDI of 100 minutes. Aggressive tree trimming on this feeder will halve the number of interruptions and reduce SAIDI to 50 minutes Considered separately, a set of automated switches will also reduce SAIDI to 50 minutes. If both projects occur, SAIDI clearly will not be reduced to zero. Considered together, the SAIDI reduction due to the automated switches is less since fewer faults occur after tree trimming In this case, both projects together will reduce SAIDI to 25 minutes.

We used the integrated solution of the pilot study to account for project interaction effects. The cost of the integrated solution of the pilot study was $4.1 million and resulted in a CMI reduction of 44%. When spending the same $4.1 million based on non-integrated analyses, CMI reduction is 65% This is a difference of 21% However, the benefits of the parametric projects were determined by examining their impact on the integrated solution, and therefore already include project interactions. As such, aggregated CMI benefits are reduced by 15% to account for project interactions.

Roadmap Cost and Benefit Summary

Roadmap costs are summarized in Table B This includes the total estimated costs for each roadmap project. It also includes incremental cost adjustments for projects in other budgets (in this case, all are related to storm hardening). The cost of the reliability roadmap is $83,077,000 over ten years. This roadmap also calls for an increase in the PSE storm hardening budget of $75,431,000 (driven mostly by a wood pole test-and-treat program) This results in a net incremental spending increase of $158,508,000, or about $15.9 million per year over ten years. These numbers are not allocated to any specific year and are not adjusted to include inflation

Roadmap benefits are summarized in Table C This includes estimated CMI (customer interruption minutes) reduction by project and by county.

SAIDI is equal to CMI divided by the number of customers served. Therefore, CMI reduction is proportional to SAIDI reduction Typically reliability benefits are computed in CMI reduction and later translated into SAIDI reduction. Table C also provides an overall $/CMI score for each project. Total estimated system SAIDI reduction is 50%, which slightly exceeds the desired reduction target.

SAIDI reduction by county varies somewhat when compared to targets. King County improvements match targets closely, which is expected since the pilot area (from which assumptions are based) is from King County The only counties that did not reach their targets are Jefferson and Kitsap. However, these two counties started out with very high SAIDI values and the actual SAIDI minutes reduced in these counties is two to three times higher than the system average When the actual roadmap is implemented, spending can be prioritized and shifted between counties to achieve desired balance

Summary

This document presents a reliability roadmap that, if followed will allow PSE to approximately halve the number of customer interruption minutes on its system. The roadmap is aggressive, calls for a variety of reliability improvement initiatives, and requires a substantial investment. However, Quanta Technology is confident in the cost estimates, the reliability improvement estimates, and the ability of the roadmap to be implemented.

This roadmap is incremental to reliability improvement programs already being pursued at PSE. Quanta Technology has reviewed these existing programs as part of the roadmap development. Future opportunities and coordination issues with the roadmap are discussed in the body of the report. Subject to these comments, Quanta Technology finds the existing PSE reliability programs appropriate.

The roadmap assumes an implemented period of ten years. However, the roadmap can be accelerated or slowed down as desired, with costs and benefits adjusting accordingly. In addition, the roadmap provides costs and benefits of each reliability improvement category separately and for each county. This allows PSE to select parts of the roadmap for a more targeted yet cost effective approach if desired

This roadmap is based on a high level analysis and required many assumptions. When reliability improvement plans are developed for specific feeders and groups of feeders, the overall mix of improvement projects described in the roadmap may or may not be applicable. PSE is encouraged to base specific reliability projects on predictive reliability models similar to the pilot study analysis detailed in the report. If this approach is pursued, PSE has a good possibility of exceeding the roadmap reliability improvement targets and significantly improving reliability for its customers in a defendable and cost justified manner.

Table B. Reliability Improvement Projects in Roadmap

	Units	$1000/ Unit	Island	Jefferson	King	Kitsap	Kittitas	Pierce	Skagit	Thurston	Whatcom	Total System	Total Cost ($1000s)
Roadmap Projects													
New 3ϕ line DA reclosers	#	38.40	4	4	62	28	3	27	18	28	32	206	7,910
New 3ϕ line reclosers	#	28.40	2	3	18	3	17	4	34	20	14	115	3,266
New manual 3ϕ switches	#	11.40	65	54	586	248	56	198	168	221	191	1,787	20,372
New UG SCADA switches	#	77.40	3	8	60	14	9	20	12	23	3	150	11,610
New OH SCADA switches	#	38.40	6	5	84	41	3	36	21	30	36	262	10,061
Animal guards	Fdrs	10.00	23	12	211	73	14	53	42	65	70	563	5,630
Spacer cable	Miles	151.00	2	1	10	4	1	1	2	8	1	30	4,530
New lateral fuses	#	2.00	100	65	1,035	380	65	315	205	310	265	2,740	5,480
Faulted circuit indicators	#	0.40	408	192	6,732	1,212	192	1,152	780	1,476	1,236	13,380	5,352
OH Feeder inspections	Miles	2.20	99	95	896	384	147	313	397	442	334	3,106	6,833
Recloser inspections	#	0.85	21	22	192	87	29	75	68	93	75	662	563
Fuse saving during storms	#	1.00	4	4	62	28	3	27	18	28	32	206	206
UG switch inspections	#	0.67	49	34	602	146	41	151	72	171	99	1,363	913
OH SCADA switch inspections	#	0.85	6	5	84	41	3	36	21	30	36	262	223
UG SCADA switch inspections	#	0.85	3	8	60	14	9	20	12	23	3	150	128
County Total Spending			$2,589	$2,369	$28,547	$10,276	$2,935	$8,998	$7,775	$11,364	$8,223		$83,077
Projects in Other Budgets													
Circuit Segmentation													-27,864
Critical Pole Hardening													30,341
Pole test-and-treat program													42,954
Danger Tree Removal													10,000
Off ROW Tree Removal													20,000
Cost of Roadmap Projects													83,077
Adjustments for other budgets													75,431
Net Cost ($1000s)													**$158,508**

Table C. Reliability Benefits of Roadmap (CMI reduction)

	Island	Jefferson	King	Kitsap	Kittitas	Pierce	Skagit	Thurston	Whatcom	Total CMI Reduction	$/CMI
Roadmap Projects											
New 3ϕ line SCADA reclosers	79,613	97,611	1,333,569	563,751	99,345	319,261	138,534	396,076	494,248	**3,522,007**	2.25
New 3ϕ line reclosers	42,137	29,929	586,367	254,160	133,548	173,414	958,831	1,218,420	430,763	**3,827,569**	0.85
New manual 3ϕ switches	984,595	790,577	5,856,322	3,561,236	441,422	1,613,129	1,618,302	3,813,230	1,671,511	**20,350,325**	1.00
New UG SCADA switches	95,309	357,578	1,732,889	532,133	183,896	459,121	284,532	1,483,295	144,892	**5,273,644**	2.20
New OH SCADA switches	119,419	132,890	1,702,283	838,574	77,812	403,208	138,065	594,114	505,245	**4,511,610**	2.23
Animal guards	229,802	182,892	1,536,810	1,004,044	123,034	394,804	483,280	990,226	544,493	**5,489,384**	1.03
Spacer cable	65,465	31,471	360,923	180,873	30,933	36,278	78,954	432,583	31,676	**1,249,157**	3.63
New lateral fuses	339,065	196,300	2,180,271	1,064,329	143,301	558,364	444,093	1,098,228	483,929	**6,507,881**	0.84
Faulted circuit indicators	205,398	250,914	2,356,854	1,158,190	78,148	390,178	337,514	794,895	470,914	**6,043,005**	0.89
OH Feeder inspections	368,590	524,019	3,556,640	2,355,833	180,098	706,182	882,209	1,604,455	1,063,791	**11,241,817**	0.61
Recloser inspections	11,260	7,635	60,131	34,637	5,238	18,864	16,919	42,003	17,697	**214,384**	2.62
Fuse Saving During Storms	7,961	9,761	133,357	56,375	9,934	31,926	13,853	39,608	49,425	**352,201**	0.58
UG switch inspections	85,488	73,560	662,580	338,994	44,231	152,856	98,346	471,983	104,471	**2,032,509**	0.45
Projects in Other Budgets											
Substation Automation	6,191	0	80,770	15,112	14,774	14,737	15,947	0	148,312	**295,844**	---
Improved Fuse Coordination	374,852	457,918	4,301,259	2,113,697	142,620	712,074	615,963	1,450,683	859,419	**11,028,484**	---
Mobile Workforce Mgmt.	71,889	87,820	824,899	405,367	27,352	136,562	118,130	278,213	164,820	**2,115,052**	---
Danger Tree Removal	161,453	104,517	1,189,427	633,767	69,478	270,025	284,739	619,838	345,921	**3,679,166**	---
Off ROW Tree Removal	161,453	104,517	1,189,427	633,767	69,478	270,025	284,739	619,838	345,921	**3,679,166**	---
Total CMI Reduction - Roadmap	2,634,105	2,685,137	22,058,996	11,943,127	1,550,940	5,257,584	5,493,432	12,979,114	6,013,056	**70,615,492**	
Total CMI Reduction - Other Budgets	775,839	754,771	7,585,782	3,801,709	323,701	1,403,425	1,319,519	2,968,573	1,864,393	**20,797,712**	
Gross CMI Reduction	3,409,944	3,439,908	29,644,778	15,744,837	1,874,642	6,661,009	6,812,951	15,947,687	7,877,448	**91,413,203**	
CMI Reduction with 15% discount	2,898,452	2,923,922	25,198,061	13,383,111	1,593,445	5,661,857	5,791,008	13,555,534	6,695,831	**77,701,223**	
SAIDI Before (min)	149.7	365.4	115.1	255.5	172.8	99.1	149.5	170.2	125.7	**143.4**	
SAIDI After (min)	65.2	195.1	65.9	137.4	31.9	41.6	46.9	54.1	54.2	**72.1**	
SAIDI Reduction (min)	84.5	170.3	49.2	118.1	141.0	57.5	102.6	116.1	71.5	**71.3**	
% SAIDI Reduction	56.4%	46.6%	42.8%	46.2%	81.6%	58.0%	68.6%	68.2%	56.9%	**49.7%**	
% SAIDI Target Reduction	42.7%	72.7%	39.8%	69.0%	32.5%	16.4%	36.7%	50.5%	29.3%	**45.7%**	

1 Introduction

Puget Sound Energy (PSE) has retained Quanta Technology to help develop a reliability roadmap. The goals of this roadmap are to (1) identify specific reliability objectives, (2) identify the most cost effective way to achieve these reliability objectives, and (3) identify additional reliability opportunities for PSE to consider in the future. The timeframe of the roadmap is ten years, but PSE has the option of accelerating many aspects of the program so that reliability benefits are realized sooner.

In order to ensure that all areas within PSE are addressed adequately in the roadmap, reliability targets are set for each county in addition to the overall system. All targets are based on the reliability index SAIDI (System Average Interruption Duration Index), which is equal to the average number of annual customer interruption minutes after major events are excluded. See Appendix C for a definition of SAIDI and other reliability indices such as SAIFI and MAIFI.

Since the counties served by PSE vary widely in terms of geography and customer density, it is not desirable to set the same target for all counties. Instead, tentative SAIDI reduction targets have been set for each county based on customer density. A survey of SAIDI versus customer density has been performed and reliability targets have been set equal to the borderline between 1st and 2nd quartile performance. An additional 25% reduction has been included to compensate for expected increases in SAIDI when a new outage management system (OMS) is deployed. Reliability targets are shown in Table 1-1, and a detailed discussion of reliability reduction targets is provided in Section 4.

As shown in Table 1-1, the reliability roadmap goals are to reduce overall system SAIDI by 45.7%. This is an ambitious goal and will require a significant investment in the system. Because of this, it is important for the roadmap to consider as many reliability improvement options as possible and to select the best mix so that SAIDI targets can be achieved in a cost effective manner. A comprehensive list of potential reliability improvement options is provided in Section 2.

Table 1-1. Reliability Reduction Targets

County	Customers (2007 Avg.)	Customer per Square Mile	IEEE SAIDI (min/yr)			SAIDI Reduction	
			'05-'07 Average	2012 Target	2017 Target	2012	2017
Whatcom	93,636	167	125.7	107.3	88.8	14.7%	29.3%
Skagit	56,453	116	149.5	122.1	94.7	18.3%	36.7%
Island	34,308	203	149.7	117.7	85.7	21.4%	42.7%
Jefferson	17,169	85	365.4	232.5	99.6	36.4%	72.7%
Kitsap	113,326	308	255.5	167.3	79.1	34.5%	69.0%
King	511,947	572	115.1	92.2	69.3	19.9%	39.8%
Kittitas	11,304	29	172.8	144.7	116.6	16.3%	32.5%
Pierce	98,443	244	99.1	90.9	82.8	8.2%	16.4%
Thurston	116,787	223	170.2	127.2	84.2	25.3%	50.5%
System	1,053,373	264	143.4	110.7	77.9	22.8%	45.7%

Notes

4 SAIDI and SAIFI are per IEEE 1366 and all counties exclude the same major event days

5 2017 SAIDI targets achieve 1st quartile reliability normalized by customer density and compensated for OMS effects

6 2012 targets are halfway between 2007 results and 2017 targets

When considering the types and magnitudes of projects to include in the roadmap, it is important to properly quantify expected benefits. For this roadmap, this means that the expected SAIDI reduction for each county must be estimated for each category of spending. Ideally, all of these estimates would be based on a thorough assessment of historical reliability data and detailed reliability models. An analysis of historical data is provided in Section 3. Modeling the entire PSE system was not practicable or cost effective for this project and benefits are therefore based on a detailed model of a pilot area. Results from the pilot area were then used to create rules for application to the rest of the system. Details of the pilot area analysis are provided in Sections 5-6. Details of the extrapolation to the rest of the PSE system is provided in Section 7

The reliability roadmap is presented in Section 8. This provides a list of reliability improvement spending categories, the amount of work expected for each category for each county, and the expected SAIDI reduction for each category The roadmap also provides estimated total spending, estimated total SAIDI reduction for each county, and estimated total SAIDI reduction for the entire system.

The reliability roadmap also includes several categories that are included in other PSE initiatives. These include programs related to aging infrastructure and programs related to system hardening. These programs are addressed in Sections 9 and 10, respectively. The roadmap recommends a few additions and subtractions from these programs, and includes all incremental cost and reliability impacts in the roadmap analysis.

The roadmap presented in this report has been developed at a high level and is based on many assumptions. When looking at potential reliability projects for specific feeders and groups of feeders, the assumptions used by the roadmap may or may not apply. However, an attempt was made to use conservative assumptions and any differences between specific feeders are likely to average out over each county and over the entire system. In any case, this roadmap should be viewed by PSE as a living plan and should be regularly reviewed and updated when additional data and information becomes available.

2 Reliability Options

When attempting to achieve significant improvements in reliability, it is important to consider as many possible reliability improvement approaches as possible. This section discusses a comprehensive list of reliability improvement tactics, the ability of these tactics to cost effectively achieve reliability, and whether PSE chose to consider each tactic within the scope of the reliability roadmap. When reliability approaches were not considered in the roadmap, discussion is provided so that PSE can properly consider these alternatives within the context of other programs or at a future time.

The remainder of this section is organized as follows. Reliability improvement tactics are grouped into broad categories that correspond to sub-sections. Within each sub-section, specific tactics are described and labeled by their treatment in the roadmap. Categories include the following:

- **Included in roadmap** – These are recommended for inclusion in the reliability roadmap
- **Included in other programs** – These are being done through other PSE initiatives, and their reliability impact is considered where possible in the roadmap.
- **For future consideration** – These are approaches that are premature to be considered at this point, but may be of value in the future.
- **Not cost effective** – These approaches were analyzed and not deemed cost effective for inclusion in the reliability roadmap.
- **Not considered** – Quanta Technology was instructed not to consider these issues within the context of the reliability roadmap.

2.1 Reclosing and Overcurrent Protection

Reclosing and overcurrent protection have a dramatic impact on reliability, and are critical to consider within a reliability roadmap. A detailed description of reclosing and overcurrent protection is provided in Appendix A.

New lateral fuses (included in roadmap)
One of the most cost effective ways to improve reliability is to ensure that all lateral taps off of the main feeder trunk are protected by at least a fuse. This prevents faults that occur on the lateral from interrupting many more customers due to the required operation of a main trunk device such as a recloser or the substation circuit breaker. Lateral fusing is used extensively in the reliability roadmap.

New 3ϕ reclosers (included in roadmap)
Most utilities pursuing significant reliability improvement are relying heavily on the installation of new 3ϕ reclosers. These devices dramatically reduce the impact of main trunk faults by not requiring the substation circuit breaker to lock out and interrupt the entire circuit. For this roadmap, two types of devices are used. For shorter feeders with high customer density, reclosers with SCADA capability are used. These devices therefore fall into the category of both "automation" and "reclosing." For longer circuits with lower customer density, the benefits of SCADA control are typically less and therefore reclosers without SCADA are recommended in the roadmap.

Protection Coordination (included in other programs)
Proper protection coordination ensures that the protection device closest to the fault operates. Miscoordination can cause backup protection to operate which impacts more customers and can make the fault more difficult to locate. PSE is proposing to perform a protection coordination study as part of its hardening program. The reliability benefits of this study are included in the roadmap.

Fuse saving during normal operations (not considered)
Fuse saving will generally result in a lower SAIDI and a higher MAIFI (see Appendix C for definitions of reliability indices). The balance of this tradeoff depends upon many factors such as lateral length and the percentage of faults that are temporary in nature. PSE believes that only about 20% of overhead faults (during normal operations) are temporary in nature, and therefore has decided not to consider fuse saving during normal operations. Since fuse saving is a very cost effective way to improve reliability for most utilities, PSE is encouraged to collect data on permanent versus temporary overhead failures and possibly pursue a fuse saving pilot study sometime in the future.

Fuse saving during storms (included in roadmap)
Temporary faults occur more frequently during storms than in normal weather. In addition, customers are more tolerant of momentary interruptions during periods of adverse weather. For these reasons, some utilities have started to turn on fuse saving during periods of adverse weather and to turn off fuse saving at the end of the storm. This approach can only be used with devices connected to the SCADA system. PSE is in the process of automating all of its substations, and will therefore be able to use this approach with all of its substation feeder breakers. In addition, a large number of new line reclosers recommended in the roadmap have SCADA. Therefore, the roadmap considers fuse saving during storms for all substation circuit breakers and for all new line reclosers with SCADA.

1ϕ reclosing and lockout (not considered)
Many new electronic line reclosers have the option to only open phases that detect fault current. Since most faults that occur on three phase overhead lines are typically single phase, two out of three phases will remain energized in these cases. Using single phase reclosing and lockout is an extremely cost effective approach for both reducing momentary interruptions and for reducing SAIDI. It is also becoming increasingly popular in the industry. However, there are certain operating concerns such as neutral current protection settings and the protection of large three phase motors. At this point, PSE has decided not to include single phase reclosing and lockout in the roadmap. PSE is encouraged to continue investigating this topic and potentially performing a pilot study sometime in the future.

TripSaver reclosers (not cost effective)
TripSavers are single phase reclosers that fit in existing fuse cutouts. When using fuse clearing, TripSavers will improve SAIDI by allowing temporary faults on downstream laterals to automatically clear themselves. Recall that PSE estimates that only 20% of all faults are temporary in nature. Also recall that the roadmap calls for the use of fuse saving during storm conditions. These two factors make TripSavers not cost effective if the 20% estimate is correct. PSE is encouraged to collect data on permanent versus temporary overhead failures and possibly pursue a TripSaver pilot study sometime in the future if certain laterals are shown to have a high percentage of temporary faults

Fuse sizing philosophy (not considered)
There are many practical implications relating to fuse sizing philosophy such as lateral fuse choice, distribution transformer fuse choice, and others. At this point, PSE is comfortable with its fuse sizing philosophy and this issue is not considered in the roadmap.

Surge arrestors & grounding (not considered)
Surge arrestors and grounding are critical for utilities subject to high lightning activity. Since the PSE service territory has low lightning activity, this issue is not a key reliability concern and is not considered in the reliability roadmap.

2.2 Manual Sectionalizing

From a reliability perspective, manual sectionalizing switches allow faults to be isolated and customers to be restored. This restoration can be further divided into upstream restoration and downstream restoration. Upstream restoration opens a switch on the path from the fault location to the substation. This allows the tripped protection device to be reset, restoring all customers upstream of the switching point. Downstream restoration attempts to restore additional customers by further isolating the fault and transferring customers to adjacent circuits. This transfer requires sufficient capacity on the transfer path. For example, a 1-MVA feeder section cannot be transferred to an adjacent circuit if it will result in overloaded equipment or will result in unacceptable voltage drops.

New manual 3ϕ switches (included in roadmap)
New manual switches on three phase main trunk lines is often overlooked as a way to improve reliability. This is unfortunate since it is potentially one of the most cost-effective ways to reduce SAIDI. The roadmap makes extensive use of new manual three phase switches on both overhead and underground parts of the PSE system.

New manual 1ϕ switches (not included in roadmap)
New manual switches on single phase laterals would potentially allow lateral faults to be isolated in a similar manner to the three phase portion of the system. However, it is more common to place fuses in locations where single phase switches would otherwise be desirable. There are probably certain locations on specific PSE feeders that could benefit from new manual single phase switches, but this was not the case for the pilot area. Therefore, new manual single phase switches were not considered in the roadmap, but PSE is encouraged to include this as a possibility when specific feeders are examined, especially feeders with long lateral branches.

New feeder tie switches (not included in roadmap)
New feeder tie switches help reliability by allowing for more aggressive downstream fault isolation and restoration. This is most effective when (1) there is no current tie switch and, (2) there is not enough spare capacity to transfer load blocks using existing tie switches. Presently most PSE feeders are not loaded to extremely high levels and load transfers between feeders can typically take place. Therefore, new feeder tie switches are not considered in this roadmap. PSE is encouraged to track actual load transfers that take place after faults to identify if and when post-fault restoration is affected by insufficient tie capacity.

Cutting jumpers for sectionalizing (not included in roadmap)
It is possible to electrically isolate faults by cutting jumpers on dead end poles. In effect, the jumpers are being used as a manual switch. This approach has both benefits and drawbacks, and PSE has concluded that the drawbacks outweigh potential reliability benefits. For this reason, this approach is not considered in the reliability roadmap.

2.3 Automation

Automation is a general term that applies to remote monitoring, remote control, and/or autonomous response of the system in response to a contingency. It is common to segment automation into substation automation, feeder automation, and customer automation. Substation automation refers to all automation within the substation fence. Feeder automation refers to automation devices on the primary distribution system. Customer automation refers to automation at the customer meter and possibly within the customer premises.

Automatic Feeder Switches (included in roadmap)
Automatic feeder switches refers to switches that can operated quickly after a fault occurs so that customers can be restored. This can be accomplished by operators sending open and closed commands over the SCADA system, by local sensors and control, by devices communicating with each other in a peer-to-peer manner, or by a centralized computer algorithm. For the purposes of the roadmap, each approach has the same effect of dramatically reducing switching time. Most utilities that are seeking to dramatically improve reliability are finding the need for extensive deployment of automated switches. It is no different for the PSE roadmap, which makes extensive use of reclosers that can be used as automatic switches, overhead automatic switches, and padmounted automatic switches.

Substation SCADA (considered in other programs)
For substations that are equipped with SCADA, the system operator is informed immediately (within a few seconds) that the feeder breaker (or recloser) has tripped automatically due to a fault. Without SCADA, the system operator must rely on reports from customers (lights out telephone calls), local agencies (Police, fire, etc), PSE field workers, and other sources. Assuming it takes 5 – 10 minutes (on average) for such calls to come in, it is theoretically possible to reduce service restoration time by 5 to 10 minutes for faults in which the feeder circuit breaker trips (note that SCADA will not help reduce restoration time for faults on feeder laterals where a fuse blows and the circuit breaker does not trip). Substation SCADA also provides remote control capabilities for the feeder circuit breaker so that it is possible to restore service to a feeder following repairs without having field crews travel to the substation to perform manual switching. Estimated savings in service restoration time through feeder breaker remote control is 5 to 10 minutes. PSE is in the process of providing all substations with SCADA, and the reliability benefits of this initiative are considered in the roadmap.

Substation Automation (not included in roadmap)
Substation automation involves the execution of sequence control logic to automatically restore service when a fault occurs in substation equipment (substation transformer, low voltage bus, etc) or supply line. One example of this is "Intelligent Bus failover" which can be applied at multi transformer, split low voltage when a transformer fault occurs, the substation automation determines how much load can be safely transferred to the 2nd transformer at the same substation or transferred by feeder automation to an alternate source that is fed from another substation. Such schemes are able to restore a sizable load with less than a minute (versus hours) when loss of supply occurs or a transformer fault occurs. The main difficulty (and expense) of implementing this scheme is that most substations do not have suitable switchgear to isolate the substation transformer (uses fuses on the high side and manual (hookstick operated) switch on the low side). Adding motor operated SCADA controlled disconnects to the transformer low side may enable PSE to deploy this scheme. Since the focus of the roadmap is on distribution, this tactic was not considered.

Implementation of Substation High-Side Circuit Breakers (not included in roadmap)

Many of the PSE substations have a single supply line to serve the station. A single supply line typically serves more than one substation that is "tapped" off the line. If a permanent fault occurs on the supply line, the customers served via substations tapped off the lines will be interrupted until all or part of the supply line is re-energized or service is restored by feeder switching. PSE has deployed an "automatic switching" scheme at some substations that opens and/or closes selected motorized disconnect switches located in the transmission line to isolate the fault line section thus allowing restoration of the unfaulted portion of the supply line. The system works reasonably well, but PSE still experiences a high percentage of customer outage minutes due to transmission line faults. By expanding the motorized disconnect functionality to include more substations or by adding high side circuit breakers to existing substations, PSE should be able to significantly reduce the customer outage minutes experienced due to supply line faults. Since the focus of the roadmap is on distribution, this tactic was not considered. Note: tapping transmission lines to feed small substations is becoming more common in the industry. Since there is no supply redundancy, these stations are typically built assuming that a mobile transformer will by deployed in the event of a substation outage.

Advanced Metering Infrastructure (not included in roadmap)

Automated meters are able to report loss of voltage at any meter, including meters served on fused lateral taps. Since the outage indication must be delivered with the power off at the meter site, the message must be sent before the meter loses its electrical charge. This is commonly referred to as a "last gasp" message. Last gasp messages provide essentially the same information as customer calls, so the incremental reliability improvement benefit is low, especially during daytime hours (improvement is greater overnight when many customers are sleeping). A problem using last gasp message is that the AMI communication network may become overwhelmed by thousands of last gasp messages during a widespread fault (note: PSE has experienced this problem). The AMI system enables the operator to "ping" selected meters to determine if power has been restored. This capability may enable PSE to conveniently detect portions of the feeder that are still out of power, thus avoiding an even longer outage. However, much of the benefits of AMI can be realized through the new outage management system that PSE will be deploying. Therefore, this tactic was not considered.

TLM using AMI (not cost effective)

The AMI system can support a very effective Transformer Load Management (TLM) program. Conventional TLM systems use statistical data to estimate the load on distribution transformers. The AMI based system uses actual aggregated customer loads to determine actual transformer load. If PSE experiences numerous transformer failures in which overload is the suspected cause, the AMI TLM system is one way to identify transformers that are seriously overloaded so that these can be replaced before failure. This is an effective way to prevent distribution transformer failures, but these failures typically only affect a few customers and therefore do not have a significant impact on SAIDI. From a roadmap perspective, this approach is not cost effective. However, this still may be a desirable initiative for PSE for other reasons.

Replacement of Electromechanical Relays with IEDs (not included in roadmap)

Microprocessor-based, protective relay intelligent electronic devices (IEDs) offer numerous benefits over their electromechanical counterparts that can result in improved reliability and other functional benefits. Presently, PSE is gradually phasing out electromechanical relays by using IEDs in new substations and when new controls are added to existing substations. Some incremental reliability improvement can be achieved by expediting the implementation of IEDs.

Enabler for Feeder Automation: Feeder automation schemes must be able to access fault data from the substation end of the feeder and must be able to distinguish between the various reasons for tripping the substation breaker. If the feeder breaker was tripped by load shedding schemes due to under frequency or other system emergency, the feeder automation scheme must not attempt to restore the load via automatic sectionalizing. Protective relay IEDs provide a convenient mechanism for distinguishing between fault tripping (feeder automation must be able to restore service under these conditions) and non-fault tripping (UFLS, UVLS, manual tripping, etc). Without IEDs in the substations, the feeder automation interface at the head end of the substation can become a "kludge".

Early Detection of Failed Relays: Failed electromechanical relays often go undetected until the relay is called to operate for a fault. If a relay fails to operate for a fault, slower operating protective devices that backup the primary relay will operate to clear a larger protection zone than needed. For example, a substation transformer fuse may blow for a feeder fault, resulting in an outage on all feeders served by that transformer rather than just the faulted feeder. All protective relay IEDs include self diagnostic capabilities that are able to automatically detect and report some relay failure modes, such as failure of an internal processor in the IED. These self diagnostics will enable PSE to detect and repair or replace the failed relay before it is called upon to operate, thus avoiding a potentially widespread outage. For estimating purposes, PSE should assume that if a feeder relay fails to generate a trip signal for a feeder fault, the transformer fuse will blow and all feeders associated with that transformer will experience an outage. If relay failures are not a significant cause of outages for PSE, then replacing electromechanical units with IEDs will not make a significant contribution to reliability improvement.

Simplified Routine Testing: Continuous IED diagnostics will not detect all types of relay problems. For example, relay output contacts usually are not included in on-line diagnostic checks. Such conditions can be identified by periodically testing each relay. Testing an IED is usually much simpler than testing the corresponding electromechanical relay(s). This is because the electromechanical protection scheme contains numerous types of relays that must be individually tested, while an IED is typically one self-contained unit that can be tested using a single set of inputs and outputs. If relay failures are not a significant cause of outages for PSE, then performing more frequent testing to detect problems before relays fail to operate will *not* make a significant contribution to reliability improvement

Fault Magnitude and Distance to Fault Information: When a feeder fault occurs, protective relay IEDs can provide information that will assist operators and field work crews in locating the fault. Relay IEDs are able to supply fault magnitude (larger magnitude means fault is close to the substation), approximate distance to fault, fault targets (a, b, c phase and neutral), etc. All of this information can be used to help pinpoint the fault and thus reduce the fault investigation time. Estimated reduction in fault investigation time is about 25% of the patrol time. There is a slight benefit in travel time because field crews can drive directly to the vicinity of the fault based on the information obtained from the relay.

The replacement of electromechanical relays with IEDs is potentially valuable from both a business perspective (i.e., spend money to save money) and from a reliability perspective. However, the reliability benefits that are enabled by IEDs are generally considered as separate initiatives (e.g., feeder automation, fault location). PSE is encouraged to assess this initiative on its own merit, but it is not explicitly considered in the roadmap.

2.4 Equipment Inspection

There are a wide number of inspection activities that could potentially have an impact on reliability It is impossible to address all possible activities in this section. Rather, the major issues (from a reliability perspective) will be addressed and the minor issues will just briefly be mentioned. PSE is encouraged to consider all possible activities when developing an inspection program, but a complete inspection program is beyond the scope of the reliability roadmap.

Overhead Feeder Visual Inspections (included in roadmap)
Many utilities are finding that regular visual inspections of feeder poles identify many problems that could result in faults if not addressed. Examples include broken crossarms, broken cross braces, cracked insulators, failed arrestors, wires sitting on crossarms, and a host of others. Since this activity is typically one of the most cost effective for improving reliability, it is considered in the roadmap.

Overhead Feeder Infrared Inspections (for future consideration)
Some utilities combine visual feeder inspections with infrared thermography. The infrared inspection is able to identify potential failures that may not be visible to the naked eye. Examples of hard-to-see problems that may be detectable through infrared inspections include broken conductor strands, poor clamps, and poor splices. Although there are potential benefits, feeder infrared inspections are most useful when done at peak loading conditions, and are expensive. Therefore, they have not been included in the roadmap. However, as PSE gains experience with visual inspections, it may want to consider supplementing the visual inspections with the targeted use of infrared.

Underground Feeder Inspections (not included in roadmap)
Underground feeder inspections include the inspection of padmounted equipment and vaults. Padmounted switch inspections are already included elsewhere in the roadmap, and vault inspections are handled through other PSE programs. Therefore, underground feeder inspections are not considered in the roadmap.

Cable Testing (not included in roadmap)
There are a host of cable testing methods that can be used to determine if a cable section is likely to fail in the near future. Some of these approaches include offline partial discharge analysis, online partial discharge analysis, tan delta measurements (similar to cable power factor), and dielectric spectroscopy. For distribution, it is difficult to justify the cost of cable testing and most utilities have stopped its use except in special circumstances. For this reason, cable testing is not considered in the roadmap.

Other Feeder Inspection Activities. (not included in roadmap)
Other inspection activities that PSE can consider in the future include feeder ultraviolet inspections, pole climbing inspections, and feeder aerial inspections, on-line condition monitoring, and various inspection activities within substations. None of these activities has been included in the roadmap.

Other Substation Inspection Activities. (not included in roadmap)
PSE already does monthly visual inspections and annual infrared inspections in its substations. The only other major possibility for substation inspections is the use of online condition monitors. These are most commonly used for power transformers and high voltage circuit breakers. At this point, it is very difficult to estimate the impact of these devices on SAIDI due to a lack of historical data. PSE may wish to explore the possible use of online condition monitors for some of its substation equipment, but it is not considered in the roadmap

2.5 Equipment Maintenance

There are a wide number of maintenance activities that could potentially have an impact on reliability. It is impossible to address all possible activities in this section. Rather, the major issues (from a reliability perspective) will be addressed and the minor issues will just briefly be mentioned. PSE is encouraged to consider all possible maintenance activities when developing a maintenance program, but a complete maintenance program is beyond the scope of the reliability roadmap.

Wood pole test and treat (considered as part of other program)
Decaying wood poles are becoming a major issue at many utilities, especially those who have not performed inspections in many years. However, decaying poles are rarely a reliability problem since adjacent poles tend to hold up poles that have lost strength to decay or other factors. Wood pole strength is important from both a safety perspective and from a storm hardening perspective. For this reason, a wood pole test and treat program is recommended, but as part of the PSE storm hardening program. No reliability benefits are assumed for normal weather conditions.

Manual switch maintenance (included in roadmap)
Manual switches can negatively impact reliability if they are needed after a fault but are not in operable condition. For example, switches could be rusted shut, blades could be misaligned, and so forth. A regular maintenance program can dramatically reduce the probability of these situations. Overhead manual switch maintenance is considered as part of overhead visual inspections. The roadmap separately considers manual switch maintenance for padmounted devices.

Automated switch maintenance (included in roadmap)
Automated switches are similar to manual switches in their potential to negatively impact reliability if they do not operate correctly when called upon. Maintenance requirements are more extensive and include issues such as control cabinets, battery systems, and communications system. The roadmap considers automated switch maintenance for both automated overhead switches and for automated padmounted switches

Other Maintenance Activities. (not included in roadmap)
Other maintenance activities that PSE can consider in the future include insulator washing, line reclosers, switched capacitors, and others. None of these activities has been included in the roadmap.

2.6 Animal Protection

Animals are one the largest causes of customer interruptions for nearly every electric utility. Problems and mitigation techniques are as varied as the animals involved. For PSE, animal protection issues have been categorized broadly into feeder protection and substation protection

Animal protection on feeders (included in roadmap)
For PSE, one of the largest issues of animal-related failures is phase-to-ground faults caused by animals bridging bushings on pole-mounted equipment. An effective way to reduce these failures is to install insulated bushing covers. Some utilities do this opportunistically when crews are already doing work on a pole top. The roadmap includes proactive work where a dedicated crew will place animal guards on a feeder with a high number of animal related interruptions.

Animal protection in substations (not included in roadmap)
Animals can be a major problem within substations. Mitigation tactics vary widely based upon the types of animals involved and the specifics within a particular substation. Animal protection in substations is not included in the roadmap because PSE addresses this issue in other budgets.

2.7 Fault Location

If faults can be found quicker, customers can be restored quicker. There are a variety of methodologies to find faults quicker, with some being tried and true and some being at the research stage. These are now discussed.

Faulted Circuit Indicators (included in roadmap)
Basic faulted circuit indicators (FCIs) provide a visual indication of whether a fault has gone through the device. This allows a crew to start at the substation and drive down the feeder, following the FCIs, directly to the fault location. Basic FCIs are very cost effective. The roadmap includes faulted circuit indicators for both overhead and underground parts of the system for the main trunk. Lateral faults can typically be found through blown fuses.

FCIs with SCADA (not cost effective)
It is possible to have FCIs that are connected to the SCADA system. These devices automatically send alarms to operators when they operate, allowing crews to drive directly to the fault location rather than having to start at the beginning of the feeder. However these devices are expensive, tend to give a large number of false alarms, and provide only marginal incremental value when compared to basic faulted circuit indicators. Therefore, these were deemed not cost effective for inclusion in the roadmap.

Fault location using relays (for future consideration)
Most modern microprocessor relays allow the electrical distance of a fault to be calculated based on pre-fault currents, fault magnitude, and circuit impedance. Effectively using this feature requires the correct input of feeder impedances into each relay, and operator training so that this data can be retrieved and utilized. Fault location using relays has potential for PSE in the future, but should probably wait until its new OMS system is deployed so that the functionality can be integrated into the OMS.

Fault location using circuit models (for future consideration)
This approach is similar to fault location using relays, but uploads fault information into a circuit model and performs a "reverse power flow" to identify possible fault locations, which can then be plotted on a geographic circuit map. Utilities using this approach have experienced dramatic reductions in fault location time, and PSE is encouraged to pursue this capability after deployment of its new OMS system.

Automatic fault classification (for future consideration)
There is current research into fault waveform analysis to identify the likely cause of a fault (e.g., tree, squirrel, lightning). This information can inform crews about what to look for when locating a fault. This technology is still in the research phase, and is not ready for commercial use.

Incipient fault detection (for future consideration)
There is current research into online waveform analysis to identify incipient faults so that they can be fixed before turning into an actual fault. This technology is still in the research phase, and is not ready for commercial use.

2.8 Outage Management System

PSE is presently working toward deploying a geographic information system (GIS). After this deployment is complete, PSE will procure and deploy a new outage management system (OMS). An OMS system allows for efficient management of distribution outages, especially during storm conditions when many outages occur at the same time.

Basic event management (not included in roadmap)
The roadmap does not include any reliability improvements due to the installation of a new OMS. It is possible that improvements may be realized, but Quanta Technology does not have sufficient information to determine whether this is the case. PSE will certainly experience benefits during major storms, but these events are typically excluded from SAIDI calculations. It is also likely that the new OMS system will capture more complete outage data. This data can then be used to further improve the roadmap. Another typical consequence of more complete data collection is an *increase* in computed SAIDI. Even if the actual customer experience has not changed, better data collection will cause calculated SAIDI values to go up. The roadmap compensates for this affect by assuming that SAIDI will go up by 25% when the new OMS is in place. This effectively lowers the reliability target of each area. PSE is encouraged to develop a data collection and analysis plan so that they can determine the actual impact of the new OMS system on SAIDI.

Mobile workforce management (included in other programs)
Mobile workforce management systems typically place global positioning systems (GPS) and mobile computers in crew vehicles. These are then integrated into the OMS or another system available to dispatchers. The dispatchers then know exactly where all vehicles are located, can identify the closest available crew for assignment to each outage, and can send instructions directly to the computer in the vehicle. PSE is pursuing mobile workforce management, and its impact on reliability is included in the roadmap.

2.9 Crew Issues

There are many crew issues that have a potential impact on reliability Examples include the following:

- Use of 1-man first responders
- Crew size
- Crew responsibilities
- Cross training
- Off-hour staffing
- Work practices
- Outage response before current job is done
- Incentive pay
- Potelco hand-off issues
- Potelco contract issues
- Staffing in anticipation of upcoming storms

PSE did not want to include the above crew issues in the reliability roadmap since there are many aspects relating to crew issues that are difficult to address in a high level roadmap. However, PSE in encouraged to consider these issues and to identify and opportunities they might have for reliability improvement.

2.10 System Design

There are many system design issues that have a potential impact on reliability. Examples include the following

- Voltage Conversion
- Remove open wire secondary
- Loop versus radial design
- Feeder layout
- Feeder loading

PSE feels comfortable with the above system design issues as they relate to reliability. Therefore, they were not included in the roadmap

2.11 Construction Standards

There are issues related to construction standards that have a potential impact on reliability. A few of these were considered for inclusion in the roadmap and most were not. Descriptions of these are now provided

<u>Use of tree wire and/or spacer cable (included in roadmap)</u>
PSE has a lot of tree related outages, and the use of covered overhead conductor has the potential to reduce the number of tree related outages. This approach can take two forms. The first uses partially-insulated wires using standard overhead construction such as crossarms. The second places partially-insulated wires into "spacer" brackets that are supported be a steel messenger with that also serves as the

neutral. The wires and messenger cable are arranged in diamond geometry. Many utilities have determined that the use of a strong messenger cable provides reliability benefits beyond those of pure tree wire. For this reason, the use of spacer cable is included in the roadmap.

Vertical versus crossarm construction (not included in roadmap)

Anecdotal evidence sometimes suggests that vertical construction has reliability benefits when compared to crossarm construction. This is presumably due to the lower probability of tree branches falling across two conductors. When contacting one utility that has switched from crossarm construction to vertical construction, it was found that the motivation was operational efficiency and there was no documented evidence of reliability differences. For this reason, the use of vertical construction was not considered as part of the roadmap. However, there may still be merit to the anecdotal stories, and PSE is encouraged to examine reliability differences for different conductor configurations.

Other construction standards not included in roadmap

There are many other aspects of construction standards that can potentially affect reliability. Some of these include: whether underground cables are in conduit or direct buried; selection of overhead wire size and type; the use of slack spans; and the selection of insulator type (e.g., polymer vs. ceramic). None of these is considered in the roadmap, but PSE is encouraged to revisit these issues periodically to identify and potential opportunities for cost reduction or reliability improvement.

2.12 Vegetation Management

PSE has a separate program for vegetation management that is addressing issues such as cycle time, different cycles for main trunk and laterals, trimming cycles by tree types, trimming standards (e.g. ground to sky), mid-cycle inspections and touch up, tree replacement, and contract management. The roadmap assumes that PSE is addressing these issues appropriately, and does not address them in the roadmap. However, the roadmap does include two incremental spending suggestions to include in the vegetation management program. These are now described.

Danger tree removal (considered in other programs)

Only a small percentage of tree related outages at PSE are due to branches falling into lines. A much higher percentage is due to dead and weakened trees falling over into lines. These outages also take a long time to repair. Danger tree removal involves a regular patrol of circuit, the identification of danger trees (both within and outside of the utility right-of-way), and their removal. The roadmap includes the reliability benefits of danger tree removal.

Off-ROW tree removal (considered in other programs)

Many tree related outages occur from trees outside of the PSE right-of-way (ROW). Typically these trees would not be addressed in the standard trimming process. Off ROW tree removal would specifically identify trees that are at a high risk for falling into PSE distribution lines. When identified, the property owners can be contacted to see if PSE can remove the tree at no charge to the customer. This type of program is experiencing increasing success around the country, and the roadmap includes the reliability benefits of off-ROW tree removal.

2.13 Distributed Resources

There are several uses of distributed resources that can have an impact on reliability. This includes the use of mobile diesel generators during a substation outage, the use of small distributed generators (e.g., solar, wind) to reduce system loading and possibly allow islanded operation, and the use of backup generators at the customer site. None of these options is appropriate for cost-effective SAIDI reduction, but may be of interest to PSE in other contexts.

The use of customer backup generators can certainly be used to improve the reliability of a specific customer. However, since the customer meter is de-energized, the customer is still officially interrupted. Customer backup generators therefore do not have an impact on SAIDI. This said, some utilities have had success offering backup generator services to customers. These programs will typically offer the design, installation, and financing of a backup generator. Typically this includes the installation of a generator, a fuel tank, an emergency electrical panel for emergency loads, and a transfer switch to transfer generation from the utility source to the generator.

2.14 Operations

There are many operational issues that impact reliability, and many are either directly or indirectly addressed by reliability improvement options already discussed. There are also additional operational approaches that can improve reliability such as the use of mobile transformers, the use of helicopters to transport crews in certain situations, and the use of live line maintenance. None of these are included in the roadmap, but PSE is encouraged to periodically review these and other operational opportunities for cost reduction and reliability improvement.

3 Historical Outage Analysis

This section presents a summary and analysis of PSE's historical outage data. The objectives of this section are to review the historical SAIDI and SAIFI values at system and county level, and to identify the most common causes of outages, in order to propose the most cost-effective alternatives for improving the reliability of PSE's system.

3.1 Historical SAIDI and SAIFI

Table 3-1 and Table 3-2 show the historical and average SAIDI and SAIFI values for PSE's service territory. These indices are used in Section 4 for defining the reliability targets for PSE's system and counties. Table 3-3 presents a summary of the main features of PSE's system.

Table 3-1. PSE's historical SAIDI values (2003-2007)

County	SAIDI (min/yr)					
	2003	**2004**	**2005**	**2006**	**2007**	**Average 05-07**
Whatcom	128.4	91.1	67.1	165.7	144.4	125.7
Skagit	143.3	98.3	138	183.1	127.3	149.5
Island	75.2	170.2	76.7	212.5	159.9	149.7
Jefferson	232.7	209.1	310.1	307.5	478.4	365.4
Kitsap	101.6	211.9	176.6	317.1	272.8	255.5
King	106.3	96.9	108.6	126.1	110.6	115.1
Kittitas	48.6	117.1	210.2	246.8	61.5	172.8
Pierce	84.9	98.1	103.4	137.1	56.8	99.1
Thurston	85.9	110.6	183.2	149	178.2	170.2
System	**105.9**	**114.9**	**124.9**	**163.9**	**141.5**	**143.4**

Table 3-2. PSE's historical SAIFI values (2003-2007)

County	SAIFI (min/yr)					
	2003	**2004**	**2005**	**2006**	**2007**	**Average 05-07**
Whatcom	0.8	0.49	0.51	0.9	0.89	0.77
Skagit	0.67	0.66	0.64	0.63	0.62	0.63
Island	0.6	0.89	0.62	1.26	0.85	0.91
Jefferson	1.36	0.73	1.85	1.1	1.43	1.46
Kitsap	0.76	1.15	1.39	1.69	1.83	1.64
King	0.71	0.77	0.81	0.97	0.78	0.85
Kittitas	0.22	0.66	0.72	0.63	0.19	0.51
Pierce	0.75	0.7	0.89	1.11	0.46	0.82
Thurston	0.49	0.87	1.11	0.94	0.81	0.95
System	**0.71**	**0.78**	**0.89**	**1.04**	**0.87**	**0.93**

From the analysis of these data in can be noticed that the SAIDI values of six out nine counties (Jefferson, Kitsap, Kittitas, Thurston, Island, and Skagit) exceed the system average. This includes two counties of relatively high customer density (Thurston and Pierce). Moreover, by analyzing Figure 3-1 it can be concluded that the SAIDI values of most counties and the system have been progressively increasing during the last five years, particularly for Jefferson and Kitsap County.

Table 3-3. Characteristics of PSE's system

County	Cust.	Sq.mi. Served	Cust/ sq.mi.	Fdrs.	Cust/ Feeder	Dist. Subs	Fdr/ Sub.	Circuit Miles OH	Circuit Miles UG	Circuit Miles Total	Miles/ Fdr
Whatcom	93,636	561	167	103	909	28	3.7	1,113	690	1,803	17.5
Skagit	56,453	488	116	65	869	20	3.3	1,322	529	1,851	28.5
Island	34,308	169	203	34	1009	10	3.4	330	343	673	19.8
Jefferson	17,169	202	85	16	1073	6	2.7	315	237	552	34.5
Kitsap	113,326	368	308	101	1122	25	4.0	1,280	1,023	2,303	22.8
King	511,947	895	572	561	913	124	4.5	2,987	4,258	7,246	12.9
Kittitas	11,304	388	29	16	707	8	2.0	490	288	778	48.7
Pierce	98,443	403	244	96	1025	28	3.4	1,042	1,065	2,107	21.9
Thurston	116,787	523	223	123	949	30	4.1	1,475	1,199	2,674	21.7
System	**1,053,373**	**3,997**	**264**	**1115**	**945**	**279**	**4.0**	**10,354**	**9,634**	**19,988**	**17.9**

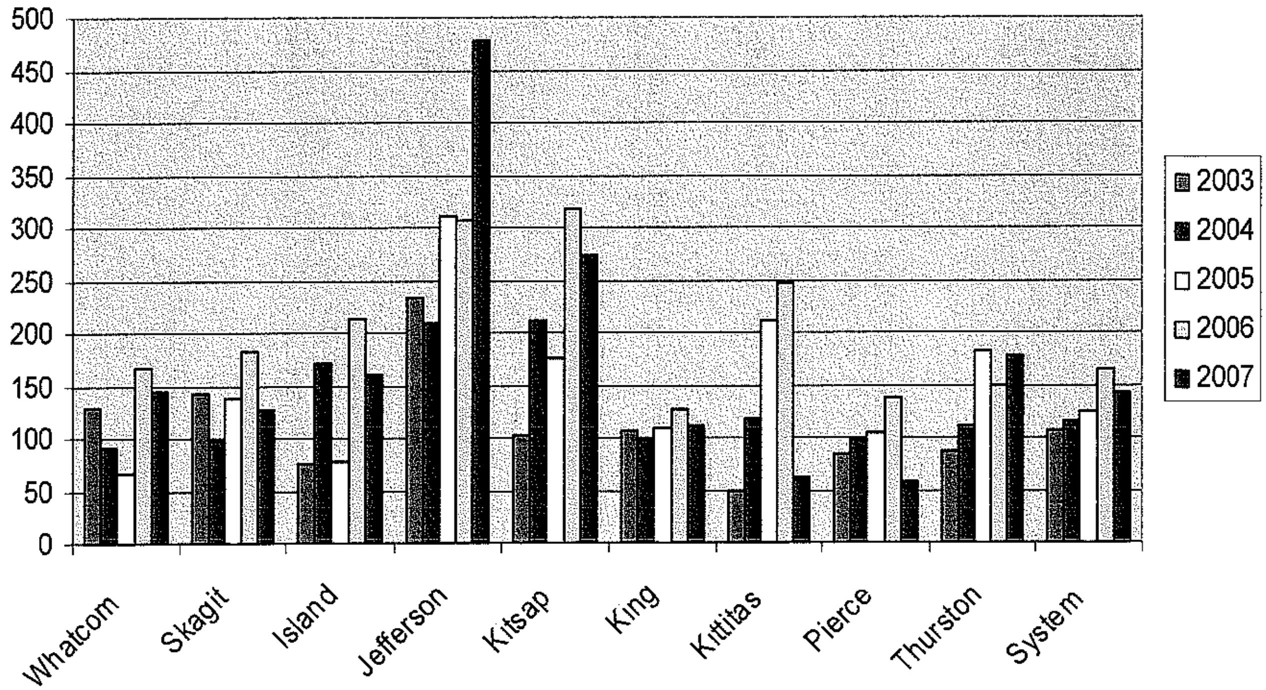

Figure 3-1. PSE's historical SAIDI values for 2003-2007 (min/yr)

3.2 Historical Outage Causes

Table 3-4 presents a summary of PSE's non-storm outage history by cause for the 2003-2007 periods. Figure 3-2 and Figure 3-3 show that almost 50% of total outages are due to equipment failures. Figure 3-3 shows the breakdown of causes that are denoted as equipment failures, which includes faults due to underground cables, overhead transformer fuses, and underground service drops. Figure 3-4 and Figure 3-5 show that, excluding equipment failures, the most common causes of outages during the 2003-2007 periods were faults due to birds and animals, trees on right-of-way, and trees off right-of-way. Table 3-4 shows that approximately 35% of total outages were due to these types of faults. This is expected, given the characteristics of PSE's service territory, where wooded areas are common, and the fact that, as shown in Table 3-3, PSE's system is 52% overhead, which makes it more prone to these type of faults.

Therefore, from this analysis, it can be concluded that the most effective alternatives for improving the reliability of PSE's system are those aimed at decreasing the frequency, and limiting the impact and extension of outages caused by faults on distribution line equipment, birds and animals, and trees on and off right-of-way. This issue is addressed in more detail in Section 6, where several alternatives for improving PSE's system reliability are proposed.

Table 3-4. PSE's non-storm outage history by cause for 2003-2007

Description	2003	2004	2005	2006	2007	Total	% of Total
Equipment Failure (EF)	6,220	5,898	5,552	5,622	4,940	28,232	45.8%
Birds and Animals (BA)	1,897	2,287	2,014	1,996	1,839	10,033	16.3%
Tree on right-of-way (TO)	1,055	874	1,066	1,746	1,119	5,860	9.5%
Tree off right-of-way (TF)	1,261	818	770	1,622	930	5,401	8.8%
Schedule Outage (SO)	372	274	804	1,038	1,134	3,622	5.9%
Dig Up (DU)	431	419	411	427	449	2,137	3.5%
Accident - Other (AO)	352	308	313	312	398	1,683	2.7%
Accident - Car/Pole (CP)	258	228	277	274	302	1,339	2.2%
Unknown (UN)	239	385	230	273	187	1,314	2.1%
Partial Outage (PO)			154	249	361	764	1.2%
Electrical Overload (EO)	39	65	66	119	125	414	0.7%
Lightning (LI)	27	79	58	38	68	270	0.4%
Customer Request (CR)	36	23	57	51	67	234	0.4%
Faulty Installation (FI)	17	24	22	29	27	119	0.2%
Operating Error (OE)	20	12	11	20	16	79	0.1%
Vandalism (VA)	4	10	4	23	18	59	0.1%
Outside Disturbance (OD)	4	1	1	5	3	14	0.0%
Normal Wore Out (NW)			2	1	1	4	0.0%
Earthquake (EQ)						0	0.0%
Total	**12,232**	**11,705**	**11,812**	**13,845**	**11,984**	**61,578**	**100.0%**

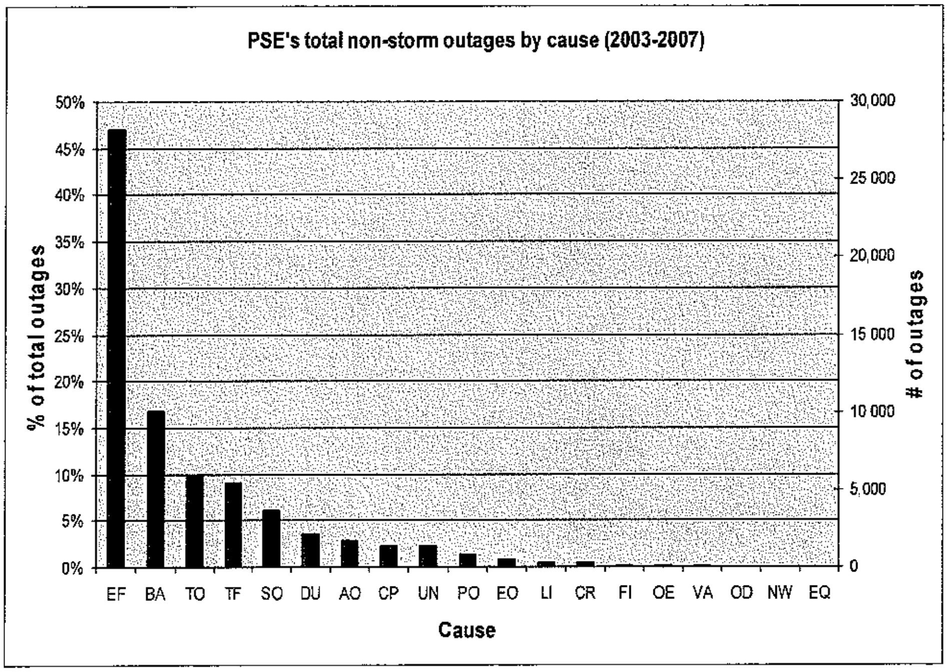

Figure 3-2. PSE's total non-storm outages by cause (2003-2007)

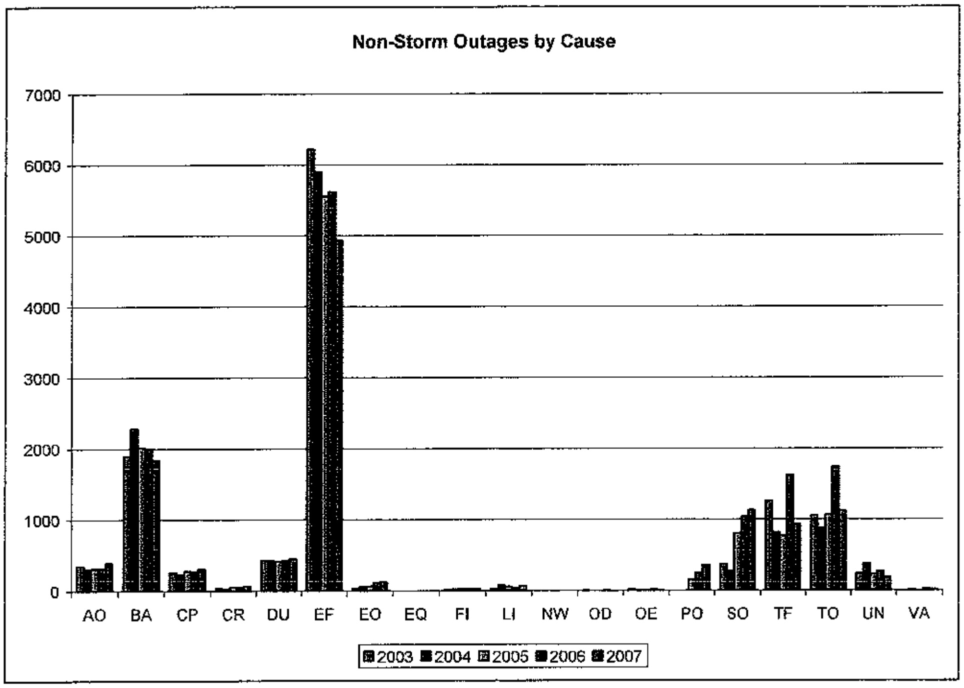

Figure 3-3. PSE's non-storm outage history by cause (2003-2007)

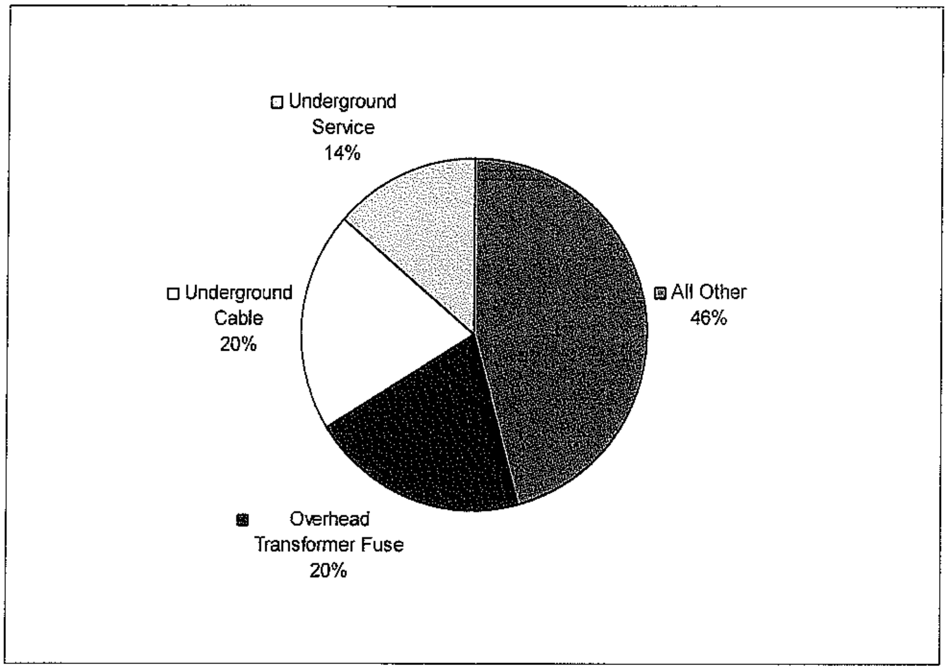

Figure3-4. PSE's non-storm total EF outages by sub-cause

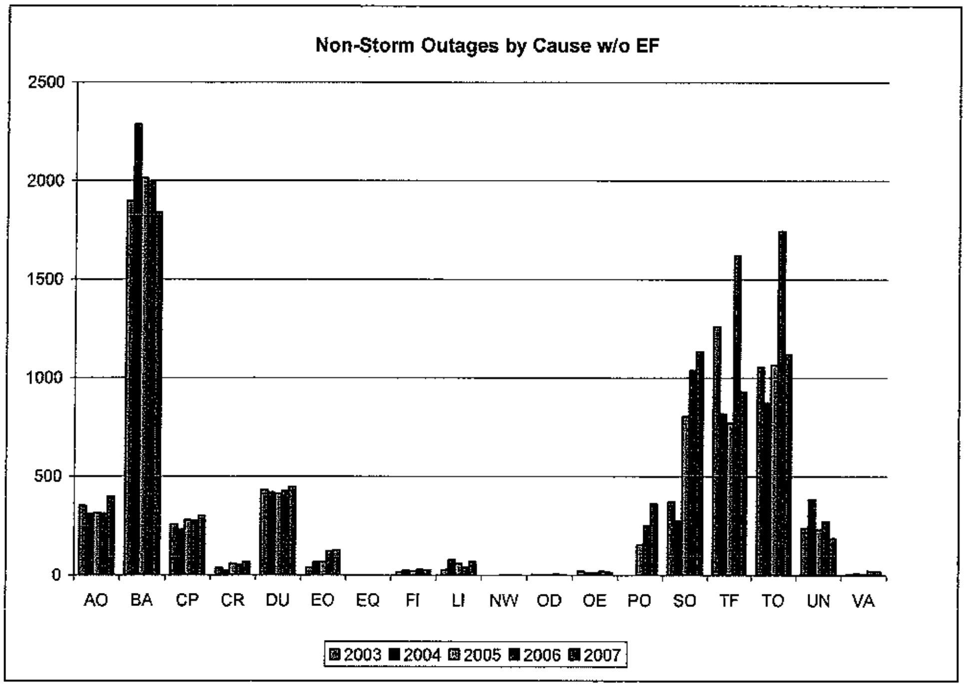

Figure 3-5. PSE's non-storm outage history by cause (excluding equipment failures)

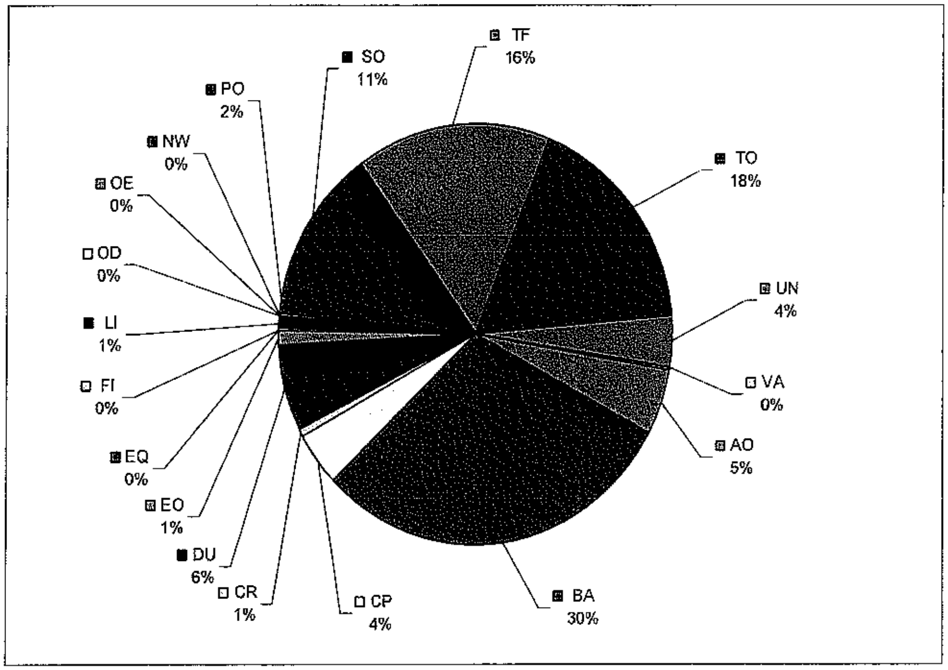

Figure 3-6. PSE's total non-storm outages by cause (excluding equipment failures)

4 Reliability Targets

When pursuing aggressive reliability improvements, it is critical to quantify reliability improvement goals with clearly defined reliability metrics and clearly identified targets. In the case of PSE, the reliability metric of primary regulatory concern is SAIDI. Since SAIDI is generally considered by the industry as the single best measure of reliability, it is an appropriate choice on which to base a reliability roadmap.

Although SAIDI does a reasonable job in tracking the reliability performance of utilities, it has the potential of allocating spending decisions that are not closely aligned with customer interests. This is especially true for utilities that are pursuing aggressive reliability goals based on system-wide SAIDI. When there is a lot of "low hanging fruit," SAIDI does a great job of spending prioritization. However, once this first round of investment is made, SAIDI may present complications.

When making reliability investments, a reduction in SAIDI is proportional to the number of affected customers. This means projects that affect many customers are preferred to those that affect few customers. In itself, this is not a problem. However, feeders with many customers typically have better-than-average reliability, and feeders with few customers typically have worse-than-average reliability. Therefore, reliability investments based on SAIDI and SAIFI can drive investments towards densely populated areas where reliability is already satisfactory.

In order to ensure that all areas within PSE are addressed adequately in the roadmap, reliability targets are set for each county in addition to the overall system. All targets are based on the reliability index SAIDI, which includes all customer interruptions including those due to transmission, substations, distribution, and scheduled outages.

Since the counties served by PSE vary widely in terms of geography and customer density, it is not desirable to set the same target for all counties. Instead, tentative SAIDI reduction targets have been set for each county based on customer density survey. This survey is now described.

4.1 Benchmark Survey

There have been many reliability benchmark surveys performed in the past. Some of these surveys allow segmentation based on the size of the utility (e.g., small, medium, large). But these surveys essentially only allow for direct comparisons of unadjusted reliability indices.

One of the problems with surveys is consistency of the responses. When computing SAIDI, some utilities may include transmission events while others may not. Some may include scheduled interruptions while others may not. There may be many different approaches to storm exclusion. This list of potential issues goes on and on.

To further complicate comparisons, surveys are almost always anonymous. Is a utility with high reliability indices a small utility serving a sparsely populated mountainous region? Or is it a major utility serving primarily a large urban area? As shown in the previous sections, proper reliability comparisons require reliability indices to be looked at in the proper context.

Table 4-1. Utilities Responding to the Benchmark Survey

BC Hydro	ComEd	LIPA	SCE
BGE	Dominion	Nevada Power	SDG&E
Black Hills	Enmax	NGRID	Sierra Pacific
Central Hudson	FPL	PG&E	Toronto Hydro
CLECO	Hydro Quebec	PPL	Wisconsin Public Service

When looking at the county reliability of PSE, it is clear that there are large differences in reliability. Since this is the case, it is of interest to know whether other utilities have similar characteristics. To examine this question, the author has performed a customized reliability survey that controls the factors related to the computation of SAIDI. This survey requests reliability results separated into dense urban areas and other areas. It also requests the population densities associated with each reported area.

The reliability survey is based on SAIDI including bulk power events, scheduled outages, and distribution outages. Major event days are excluded based on the IEEE 2.5 Beta methodology. In all, twenty one utilities responded to the survey including sixteen U.S. utilities and four Canadian utilities. These twenty one utilities provided reliability and customer density information for seventy nine separate areas. Table 4-1 shows all of the responding utilities (in addition to PSE).
The goal of the study is to identify performance thresholds for quartiles, but adjusting for customer density. Customer density was chosen since it is easy to obtain, and is independent of system design choices such as the percentage of circuit miles that are underground and the number of customers per circuit mile. To compute reliability versus customer density quartiles, the following steps were followed:

Steps to compute reliability versus customer density quartiles

1. Generate a scatter plot of SAIFI versus customer density and SAIDI versus customer density. These scatter plots each consist of 79 data points corresponding to the 79 areas identified in the benchmark surveys.
2. Identify the 50% "average performance level" by identifying the best curve fit for the data points. Based on maximizing the coefficient of determination (R^2), the best fit turns out to be logarithmic.
3. Identify the 25% "third quartile" level by shifting the 50% curve up until 25% of data points are above curve.
4. Identify 75% level by shifting 50% curve down until 25% of data points are below curve.

Results of this process for SAIDI are shown in Figure 4-1. In each case, the lognormal curve fit does a good job of segmenting the data into halves. In terms of descriptive power, the industry SAIDI model has an R^2 value of 0.2398. this means that customer density describes about 25% of the SAIDI data variation.

The red dots in Figure 4-1 correspond to the PSE counties (the overall PSE system is also shown). These can be compared to the target first quartile, which is represented by the line marked "75%." These PSE values are based on the current PSE outage reporting systems and processes. It is expected that computed SAIDI will increase after PSE implements a new outage management system. This would effectively shift all of the PSE data points upwards on the graph.

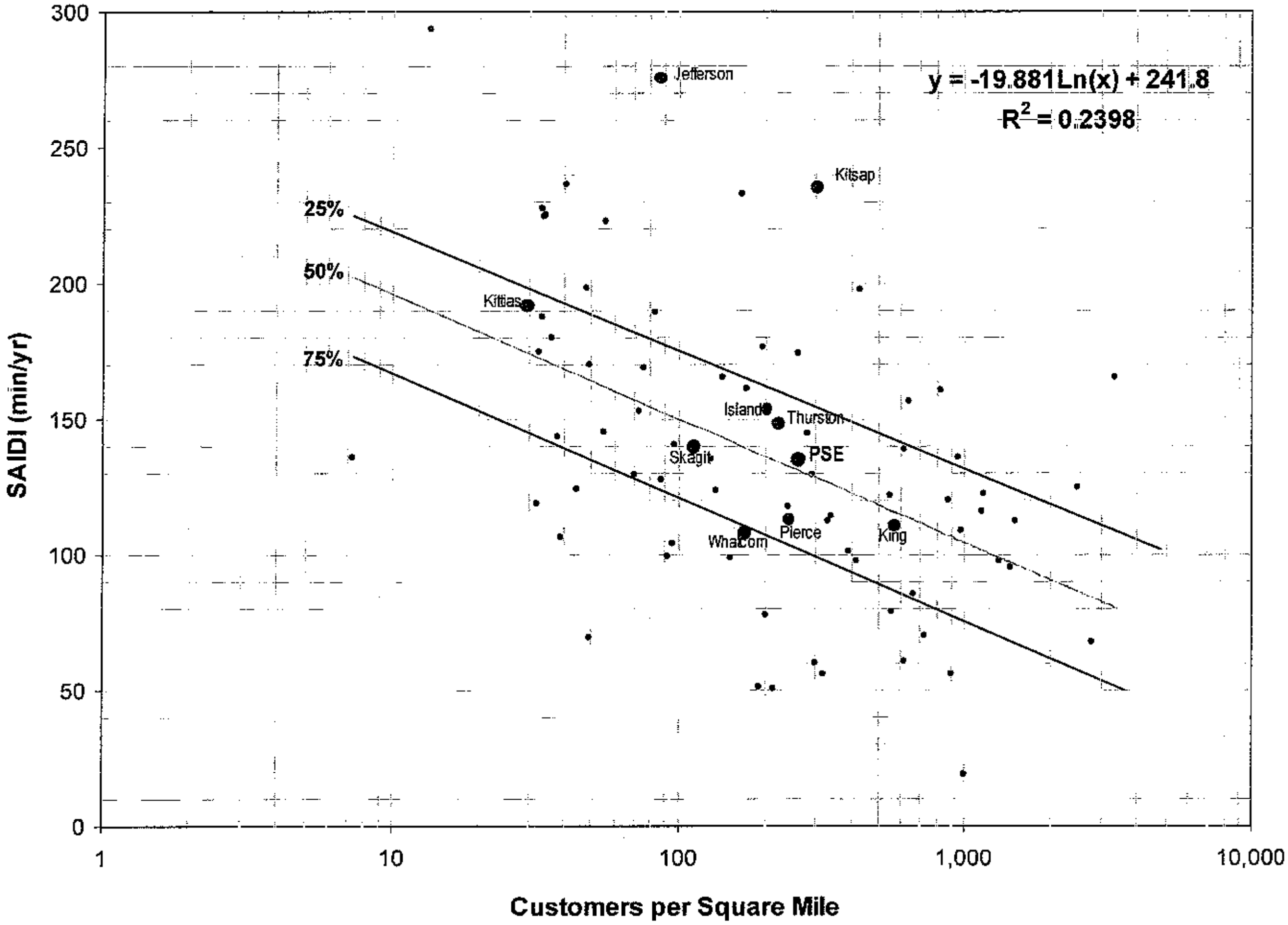

Figure 4-1. Results of Customer Density Survey

4.2 Reliabilty Targets

When setting reliability targets, it is important to consider three things. First it is important to choose a good metric or set of metrics. Second, it is important to have a clear definition of the selected metrics. Third, it is important to select appropriate targets for these metrics. This section addresses each of these three issues as they relate to the PSE reliability roadmap.

Reliability targets are based on SAIDI using the IEEE 2.5 Beta method for storm exclusion. Reliability index definitions, including the 2.5 Beta method, are provided in Appendix C.

Tentative SAIDI reduction targets have been set for each county based on the customer density benchmark survey. Reliability targets have been set equal to the borderline between 1st and 2nd quartile performance. Current reliability is based on average SAIDI values for 2005-2007. These targets are equivalent to shifting all of the red dots in Figure 4-1 down to the line labeled "75%."

Table 4-2. Reliability Reduction Targets

County	Customers (2007 Avg.)	Customer per Square Mile	IEEE SAIDI (min/yr)			SAIDI Reduction	
			'05-'07 Average	2012 Target	2017 Target	2012	2017
Whatcom	93,636	167	125.7	107.3	88.8	14.7%	29.3%
Skagit	56,453	116	149.5	122.1	94.7	18.3%	36.7%
Island	34,308	203	149.7	117.7	85.7	21.4%	42.7%
Jefferson	17,169	85	365.4	232.5	99.6	36.4%	72.7%
Kitsap	113,326	308	255.5	167.3	79.1	34.5%	69.0%
King	511,947	572	115.1	92.2	69.3	19.9%	39.8%
Kittitas	11,304	29	172.8	144.7	116.6	16.3%	32.5%
Pierce	98,443	244	99.1	90.9	82.8	8.2%	16.4%
Thurston	116,787	223	170.2	127.2	84.2	25.3%	50.5%
System	1,053,373	264	143.4	110.7	77.9	22.8%	45.7%

Notes

7. SAIDI and SAIFI are per IEEE 1366 and all counties exclude the same major event days
8. 2017 SAIDI targets achieve 1st quartile reliability normalized by customer density and compensated for OMS effects
9. 2012 targets are halfway between 2007 results and 2017 targets

An additional 25% reduction has been included to compensate for expected increases in SAIDI when a new outage management system (OMS) is deployed. Reliability targets are shown in Table 4-2.

As shown in Table 4-2, the reliability roadmap goals are to reduce overall system SAIDI by 45.7%. This is an ambitious goal and will require a significant investment in the system. Targets by county vary widely, with a modest improvement of 16.4% for Pierce County and dramatic improvements of around 70% for both Jefferson County and Kitsap County. These targets are simply a result of the benchmark survey and only consider expected reliability differences associated with customer density. There may be other factors such as geography that allow for justification of reliability targets to be higher or lower than these target benchmark values. These factors may even make achieving some of the county targets cost prohibitive. Regardless, setting reliability targets based on industry-wide benchmark information is a good initial starting point from which to base the reliability roadmap.

5 Pilot Area Predictive Reliability Model

5.1 Pilot Area Description

The modeled Pilot Area was located in King County, consisting of approximately 8 substations, of which, emanates a total of 30 feeders. These 12.5KV feeders had an average main truck feeder length of approximately 4.3 miles with roughly 305 lateral taps per feeder. The pilot area contains about 40,173 metered customers served by 185 miles of overhead and 310 miles of underground distribution line; this total represents about 7% of the customers served in King County.

5.2 Calibrated Pilot Area Model Description

Paramount to any predictive reliability analysis is a calibrated system model, calibrated here meaning that the results of the model reflect the historical reliability of the system that it represents. To start the calibration process our team received historic system reliability data in the form of reliability indices (SAIDI and SAIFI) from PSE. We received average SAIDI and SAIFI values for the last 5 years, calculated based on the IEEE 2.5 Beta method for storm exclusion. To accurately model or reflect the ensuing five years of average SAIDI and SAIFI values, our team made the following assumptions:

- Allow feeder reclosing on all feeders
- All automatic switches and automatic transfer switches have an operation time of 1 min.
- 75% of the faults that occur are treated as single phase faults
- Momentary events have duration less than 1 min.
- Sustained failure rates for overhead lines are 2.5 times that of the sustained failure rate for underground lines.
- Momentary failure rates for overhead lines are 0.5 times that of the sustained failure rates for overhead lines. This means that 33% of all overhead failures are temporary.
- Momentary failure rates for underground circuits are assumed to be zero.
- Mean time to repair for overhead lines is 0.5 times that of the mean time to repair the underground counterpart.
- Fuses have a failure rate of 0.009 f/yr/mi and a mean time to repair of 2 hrs.
- Switches have a failure rate of 0.014 f/yr/mi and a mean time to repair of 4 hrs.
- Sectionalizers have a failure rate of 0.014 f/yr/mi and a mean time to repair of 4 hrs
- Transformers have a failure rate of 0.010 f/yr/mi and a mean time to repair of 5 hrs.
- Breakers have a failure rate of 0.010 f/yr/mi and a mean time to repair of 12 hrs
- Reclosers have a failure rate of 0.010 f/yr/mi and a mean time to repair of 5 hrs

Please note that these assumptions are based on a combination of sources such as PSE data, books, journals, conference proceedings and different manufacturer test data.

The calibrated results for SAIDI and SAIFI are shown below in Table 5-1 and Table 5-2 respectively. Specifically Table 5-3 shows the Substations along with the associated feeders, the historic SAIFI values used for the target, the actual calibrated SAIFI, and finally the sustained and momentary failure rates for the overhead, along with the sustained failure rates for underground circuits. Table 5-2 shows the Substations along with the associated feeders, the historic SAIDI values used for the target, the actual calibrated SAIDI, and finally the mean time to repair the overhead and underground circuits.

Table 5-1. Calibrated SAIFI Values For The Pilot Area Model

		SAIFI				
		SAIFI		Failure Rate		
Station	Circuit	Target	Actual (System Run)	OH Sustained	OH Momentary	UG Sustained
Vitulli	VIT-16	0.01	0.05	0.02067	0.04135	0.00827
	VIT-18	0.53	0.53	0.84794	1.69589	0.33918
	VIT-22	0.02	0.02	0.00105	0.00210	0.00042
	VIT-23	0.75	0.74	0.15321	0.30642	0.06128
Wayne	WAY-12	0.44	0.44	0.21700	0.43399	0.08680
	WAY-13	1.12	1.12	0.30239	0.60478	0.12096
	WAY-15	1.59	1.59	0.35829	0.71658	0.14332
	WAY-16	0.49	0.49	0.09794	0.19589	0.03918
Lake Leota	LLT-13	0.64	0.64	0.12698	0.25396	0.05079
	LLT-15	0.33	0.33	0.04207	0.08415	0.01683
	LLT-16	2.32	2.33	0.33124	0.66249	0.13250
	LLT-17	0.82	0.82	0.24516	0.49032	0.09806
North Bothell	NBO-22	0.61	0.61	0.14217	0.28434	0.05687
	NBO-25	0.36	0.37	0.15559	0.31117	0.06223
	NBO-26	0.81	0.81	0.19675	0.39349	0.07870
Hollywood	HWD-22	1.06	1.06	0.19957	0.39914	0.07983
	HWD-23	0.48	0.48	0.07914	0.15829	0.03166
	HWD-25	0.54	0.55	0.07947	0.15895	0.03179
	HWD-26	0.80	0.80	0.22679	0.45359	0.09072
Inglewood	ING-13	1.31	1.31	0.35832	0.71664	0.14333
	ING-15	1.58	1.58	0.27707	0.55415	0.11083
	ING-16	0.98	0.98	0.42275	0.84549	0.16910
Kenmore	KNM-23	0.99	0.99	0.21633	0.43265	0.08653
	KNM-25	0.26	0.26	0.04870	0.09740	0.01948
	KNM-26	0.62	0.62	0.12020	0.24040	0.04808
	KNM-27	1.19	1.19	0.42871	0.85742	0.17148
Norway Hill	NHL-13	0.30	0.29	0.09408	0.18816	0.03763
	NHL-15	0.10	0.21	0.00679	0.01358	0.00272
	NHL-16	0.31	0.31	0.26881	0.53761	0.10752
	NHL-17	0.93	0.93	0.26396	0.52792	0.10558

Table 5-2. Calibrated SAIDI values for the pilot area model

		SAIDI			
		SAIDI		MTTR	
Station	Circuit	Target	Actual (System Run)	OH MTTR	UG MTTR
Vitulli	VIT-16	1.83	7.23	2.39	4.78
	VIT-18	98.24	98.24	3.05	6.09
	VIT-22	7.26	7.20	40 97	81 94
	VIT-23	97.58	97.58	7.34	14.68
Wayne	WAY-12	81.34	81.34	5.19	10 37
	WAY-13	105.53	105.53	2.23	4.46
	WAY-15	161.35	161.36	3.10	6.21
	WAY-16	91.76	91.75	7.30	14.59
Lake Leota	LLT-13	84 04	84.05	4 17	8.34
	LLT-15	25.38	25.38	1 39	2.77
	LLT-16	203.51	203.51	2.34	4.67
	LLT-17	129.08	129.08	3.02	6.03
North Bothell	NBO-22	62.62	62.54	2.19	4.38
	NBO-25	40.17	40.18	3.96	7.91
	NBO-26	112.99	113.00	4.34	8.68
Hollywood	HWD-22	112.30	112.29	2.28	4.57
	HWD-23	76.58	76.58	5.82	11.64
	HWD-25	91.01	91.01	8.79	17.58
	HWD-26	137.36	137.36	5.68	11.35
Inglewood	ING-13	131 71	131.72	3.64	7.29
	ING-15	151.41	151.41	3.34	6.69
	ING-16	159.10	159.10	3.02	6.05
Kenmore	KNM-23	145.68	145.68	5.35	10 69
	KNM-25	20.32	20.32	1.53	3.05
	KNM-26	95.58	95.59	9.14	18.28
	KNM-27	145.84	145.84	2.69	5.38
Norway Hill	NHL-13	88.98	88.72	15.70	31 40
	NHL-15	22.76	16.94	4.18	8.35
	NHL-16	41.74	41.74	2 35	4 70
	NHL-17	108.40	108.41	3.31	6.61

6 Pilot Area Reliability Assessment

This section presents a detailed explanation of the alternatives projected for improving the reliability of the pilot study area and PSE's system, in order to achieve the planned reliability targets. Each alternative includes a cost estimation description, a summary of the reliability benefits (SAIDI and SAIFI), and a cost-effectiveness analysis. All the assumptions described in this section apply to both, the pilot study area and PSE's system. The reliability benefits and cost-effectiveness results were calculated by assuming the individual implementation of each alternative. The results of implementing an integrated solution, which considers the combined benefits and interactions of several alternatives, are presented in Subsection 6.21 (for the pilot study area), and Section 7.

6.1 Option 1: New three-phase DA reclosers

This alternative entails the installation of new three-phase Distribution Automation reclosers (DA reclosers) on main trunks and branches (line reclosers). A DA recloser is a modern microprocessor-based recloser that is outfitted with communications, so that it can quickly be opened and closed from a control centre after a fault occurs. Moreover, the communication capability allows the distribution operator to remotely modify the recloser's settings (e.g. number of reclosing attempts, fuse saving/fuse clearing mode, etc). Here it is important to highlight that the main goal of adding communications to these devices is to exploit the combined effects of DA reclosers and DA tie switches, e.g., by performing automatic load transfers and restorations during outages. The combined reliability benefits of both alternatives are discussed in Section 6.21.

For the reliability assessment of the system and the pilot study area, it is assumed that each DA recloser will be installed in a new location. Moreover, for storm hardening purposes, each new DA recloser will be installed on a new 40 feet, Class 2 pole and will replace an existing pole. Besides, according to PSE's protection philosophy requirements, all DA reclosers will be set to "fuse clearing" mode, as well as three-phase tripping and three-phase lockout. Finally, for the reliability modeling using SynerGEE, it is assumed that a DA recloser has a failure rate of 0.0150 faults/year, and a repair time of 4 hours, which are typical industry values.

Costs

The assumed cost of each DA recloser is $38,400 per location. This amount was calculated by using the values provided by the PSE cost estimation tool, and includes the material and labor costs for installing the recloser ($23,446.46), replacing pole ($4,931.50), and adding the communications equipment ($10,000).

The total number of DA reclosers that will be installed is: one for feeders with overhead exposure between 10-25 miles, and two units for feeders with overhead exposure between 25-35 miles. Existing reclosers are subtracted from this amount. For example, an existing feeder with 30 miles of overhead exposure and an existing recloser is assigned one new unit.

Table 6-1. SAIDI reduction of the "DA reclosers" alternative (fuse clearing)

#	Feeder	SAIDI Before (min)	SAIDI After (min)	SAIDI reduction (%)
1	ING15-DAR	151.41	135.27	11%
2	ING16-DAR	159 10	130.75	18%
3	LLT16-DAR	218 38	152.21	30%
4	KNM27-DAR	148 71	89.58	40%
5	WAY15-DAR	161 36	140 31	13%
6	KNM23-DAR	144.32	124.32	14%
7	WAY16-DAR	91.74	64 95	29%
8	WAY13-DAR	105.33	81.11	23%
9	ING13-DAR	131 72	120.83	8%
10	NBO22-DAR	62.48	50 71	19%
11	LLT13-DAR	84.05	67 34	20%
12	NHL13-DAR	88.72	82 30	7%
13	WAY12-DAR	81.34	66 72	18%
14	NBO26-DAR	113.00	85 92	24%
15	KNM26-DAR	95.16	89 17	6%
16	VIT23-DAR	97 60	89.45	8%
17	HWD25-DAR	91.01	84.75	7%
18	NHL17-DAR	108.41	94.78	13%
19	LLT17-DAR	129.08	120.85	6%
20	KNM25-DAR	20.32	16 56	19%
21	NHL15-DAR	22.76	20.11	12%
22	HWD26-DAR	137.32	126.34	8%
23	LLT15-DAR	25 71	21 82	15%
24	HWD23-DAR	76.58	67.64	12%
25	HWD22-DAR	112.29	110.68	1%
26	NBO25-DAR	40 18	38 22	5%
27	NHL16-DAR	41.75	-	-
28	VIT16-DAR	7.23	-	-
29	VIT18-DAR	98 24	-	-
30	VIT22-DAR	7.4	-	-
Pilot Study Area		**94.82**	**81.56**	**14%**

Reliability Benefits

Table 6-1 shows the reliability improvements obtained by implementing the "DA reclosers" alternative for the pilot study area. This alternative is not feasible for some feeders that are mostly or completely underground (e.g., feeder NHL-16). The SAIDI reduction is calculated as a percentage of the SAIDI base value, which is defined as the SAIDI value calculated by using the historical outage data. The average SAIDI reduction for the pilot study area is 14%. Here it is important to highlight that no reclosers were modeled for feeders that are mostly (more than 90%) underground.

Based on the results of Table 6-1, the SAIDI reduction for PSE's system is assumed to be 10% per device added. This is a conservative assumption that is intended to take into account a reduction in the efficacy of installing DA reclosers, due to the differences between the pilot study area and PSE's system. A total of 32 new DA reclosers were modeled in the pilot study area, this represents an average of 1.2 reclosers per feeder. The SAIDI reduction for feeders with 1 new recloser was an average of 12.1%, and the SAIDI reduction for feeders with 2 new reclosers was an average of 23.9%.

Cost-Effectiveness

Table 6-2 and Figure 6-1 show the results of the cost-effectiveness analysis of implementing the "DA reclosers" alternative for the pilot study area. An accepted industry practice is that the most efficient alternatives for improving reliability should have a cost-effectiveness greater than 0.5 CMI/$, or equivalently, a cost-effectiveness less than 2.0 $/CMI.

From the analysis of Table 6-2 it can be concluded that this alternative is cost-effective for about 30% of the feeders. However, its average cost-effectiveness for the pilot study area is 0.39 CMI/$, which is less than the threshold of 0.5 CMI/$. This is due to the fact that the pilot study area is predominantly underground (64% underground), and reclosers are only installed in feeders that are mainly overhead. Moreover, reclosers are less efficient when they are used in a "fuse blowing" protection scheme. In a "fuse blowing" protection scheme, temporary faults will always cause the blowing of fuses, limiting the benefits of reclosers to a relatively small portion of the feeder. However, in a "fuse saving" protection scheme, the reclosing capability of reclosers allows for temporary faults to self-extinguish, avoiding the blowing of fuses, and extending the reliability benefits along most sections of a feeder. If a global "fuse saving" protection scheme is used for the pilot study area, the average cost-effectiveness of the "DA reclosers" alternative increases to 0.62 CMI/$, which represents an increment of approximately 60% with respect to the "fuse blowing" case. Moreover, this alternative becomes cost-effective for approximately 62% of feeders, which represents an increment of approximately 100% with respect to the "fuse blowing" case. These results are shown in Table 6-3 and Table 6-4, where it can be noticed that the SAIDI reduction of all feeders and the pilot study area also increases. Here it is important to highlight that implementing a "fuse saving" scheme does not represent an incremental cost for PSE. Therefore, it is highly recommended for PSE to consider the implementation of a global "fuse saving" scheme in combination with the installation of DA reclosers.

Table 6-2. Cost-effectiveness of the "DA reclosers" alternative (fuse clearing)

#	Feeder	Customers	CMI reduction	Cost ($)	CMI reduction / $
1	ING15-DAR	2708	43 707	38 400	1 14
2	ING16-DAR	1335	37 847	38 400	0 99
3	LLT16-DAR	1011	66 898	76 800	0 87
4	KNM27-DAR	1053	62 264	76,800	0.81
5	WAY15-DAR	1362	28 670	38 400	0 75
6	KNM23-DAR	1396	27 920	38,400	0 73
7	WAY16-DAR	1598	42 810	76 800	0 56
8	WAY13-DAR	756	18 310	38 400	0 48
9	ING13-DAR	1615	17 587	38 400	0 46
10	NBO22-DAR	1316	15 489	38 400	0 40
11	LLT13-DAR	817	13 652	38 400	0 36
12	NHL13-DAR	2000	12 840	38 400	0 33
13	WAY12-DAR	816	11 930	38 400	0 31
14	NBO26-DAR	689	18,658	76 800	0 24
15	KNM26-DAR	1420	8,506	38 400	0 22
16	VIT23-DAR	1963	15,998	76 800	0 21
17	HWD25-DAR	1224	7 662	38 400	0 20
18	NHL17-DAR	548	7 469	38 400	0 19
19	LLT17-DAR	883	7 267	38 400	0 19
20	KNM25-DAR	1900	7 144	38 400	0 19
21	NHL15-DAR	2664	7 060	38 400	0 18
22	HWD26-DAR	574	6 303	38 400	0 16
23	LLT15-DAR	1073	4 174	38 400	0 11
24	HWD23-DAR	524	4 685	76 800	0 06
25	HWD22-DAR	1339	2 156	38 400	0 06
26	NBO25-DAR	872	1 709	38 400	0 04
27	NHL16-DAR	1885	-	-	-
28	VIT16-DAR	871	-	-	-
29	VIT18-DAR	129	-	-	-
30	VIT22-DAR	133	-	-	-
Pilot Study Area		**36474**	**483,645**	**1,228,800**	**0.39**

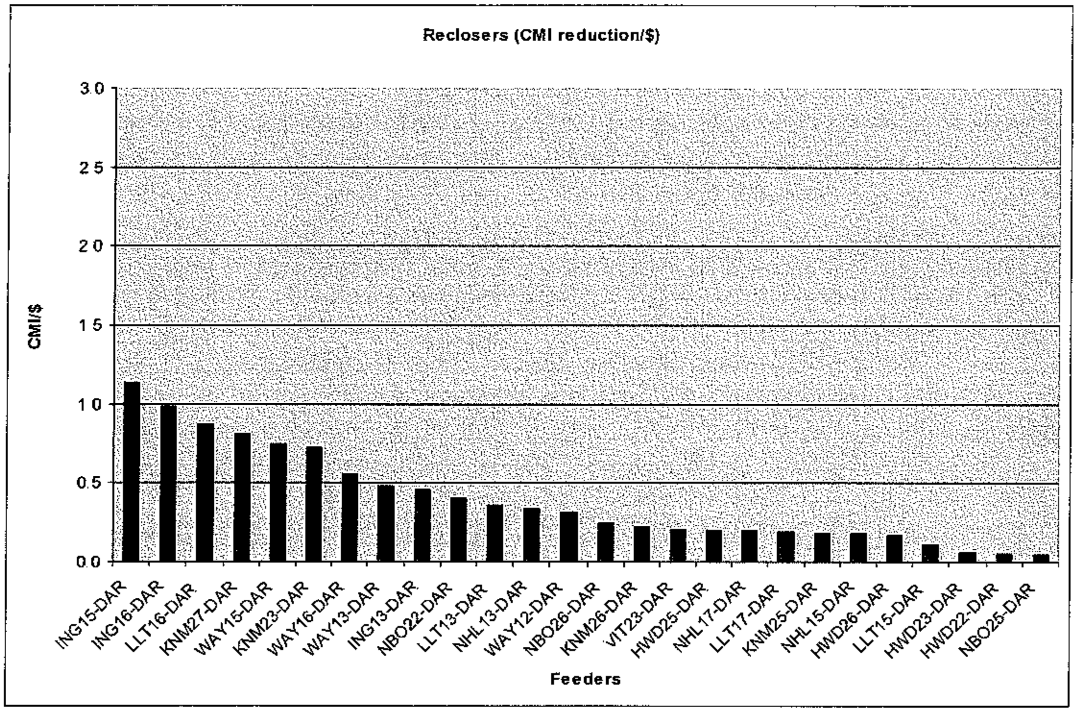

Figure 6-1. Cost-effectiveness of the "DA reclosers" alternative

Table 6-3. SAIDI reduction of the "DA reclosers" alternative (fuse saving)

#	Feeder	SAIDI Before (min)	SAIDI After (min)	SAIDI reduction (%)
1	ING15-DAR	151.41	120.16	21%
2	ING16-DAR	159.10	126.59	20%
3	LLT16-DAR	218.38	147.69	32%
4	KNM27-DAR	148.71	80.24	46%
5	WAY15-DAR	161.36	132.79	18%
6	KNM23-DAR	144.32	115.43	20%
7	WAY16-DAR	91.74	64.37	30%
8	WAY13-DAR	105.33	75.28	29%
9	ING13-DAR	131.72	109.61	17%
10	NBO22-DAR	62.48	47.36	24%
11	LLT13-DAR	84.05	61.70	27%
12	NHL13-DAR	88.72	69.59	22%
13	WAY12-DAR	81.34	56.08	31%
14	NBO26-DAR	113.00	78.10	31%
15	KNM26-DAR	95.16	61.35	36%
16	VIT23-DAR	97.60	85.83	12%
17	HWD25-DAR	91.01	69.69	23%
18	NHL17-DAR	108.41	80.40	26%
19	LLT17-DAR	129.08	115.64	10%
20	KNM25-DAR	20.32	16.09	21%
21	NHL15-DAR	22.76	19.85	13%
22	HWD26-DAR	137.32	118.57	14%
23	LLT15-DAR	25.71	21.68	16%
24	HWD23-DAR	76.58	67.47	12%
25	HWD22-DAR	112.29	91.41	19%
26	NBO25-DAR	40.18	31.66	21%
27	NHL16-DAR	41.75	-	-
28	VIT16-DAR	7.23	-	-
29	VIT18-DAR	98.24	-	-
30	VIT22-DAR	7.4	-	-
Pilot Study Area		**94.82**	**74.1**	**22%**

Table 6-4. Cost-effectiveness of the "DA reclosers" alternative (fuse saving)

#	Feeder	Customers	CMI reduction	Cost ($)	CMI reduction / $
1	ING15-DAR	2708	84 625	38,400	2 20
2	ING16-DAR	1335	43 401	38,400	1 13
3	LLT16-DAR	1011	71 468	76 800	0 93
4	KNM27-DAR	1053	72 099	76,800	0 94
5	WAY15-DAR	1362	38 912	38,400	1 01
6	KNM23-DAR	1396	40 330	38,400	1 05
7	WAY16-DAR	1598	43 737	76 800	0 57
8	WAY13-DAR	756	22 718	38 400	0 59
9	ING13-DAR	1615	35 708	38 400	0.93
10	NBO22-DAR	1316	19 898	38 400	0 52
11	LLT13-DAR	817	18,260	38 400	0 48
12	NHL13-DAR	2000	38 260	38 400	1 00
13	WAY12-DAR	816	20 612	38 400	0 54
14	NBO26-DAR	689	24 046	76 800	0 31
15	KNM26-DAR	1420	48 010	38 400	1 25
16	VIT23-DAR	1963	23 105	76 800	0 30
17	HWD25-DAR	1224	26 096	38 400	0 68
18	NHL17-DAR	548	15 349	38,400	0.40
19	LLT17-DAR	883	11,868	38,400	0.31
20	KNM25-DAR	1900	8 037	38 400	0 21
21	NHL15-DAR	2664	7,752	38 400	0 20
22	HWD26-DAR	574	10,763	38 400	0 28
23	LLT15-DAR	1073	4 324	38 400	0 11
24	HWD23-DAR	524	4,774	76 800	0 06
25	HWD22-DAR	1339	27 958	38 400	0 73
26	NBO25-DAR	872	7 429	38 400	0 19
27	NHL16-DAR	1885	-	-	-
28	VIT16-DAR	871	-	-	-
29	VIT18-DAR	129	-	-	-
30	VIT22-DAR	133	-	-	-
Pilot Study Area		**36474**	**755,741**	**1,228,800**	**0.62**

Using the assumptions presented in this section, the overall cost-effectiveness of this alternative for PSE's system is 2.25 CMI/$, which significantly exceeds the threshold value of 0.5 CMI/$. Therefore, this is a very cost-effective alternative for improving PSE's system reliability. Moreover, if this alternative is combined with a "fuse saving" scheme, its cost-effectiveness is expected to increase further.

6.2 Option 2: New Three-Phase Reclosers

This alternative entails the installation of new three-phase non-DA reclosers on main trunks and branches. These microprocessor-based reclosers are not outfitted with communications, and are intended for long overhead feeders, e.g., rural feeders

For the reliability assessment of the system and the pilot study area, it is assumed that each recloser will be installed in a new location. Moreover, for storm hardening purposes, each new recloser will be installed on a new 40 feet, Class 2 pole and will replace an existing pole. Besides, according to PSE's protection philosophy requirements, all reclosers will be set to "fuse clearing" mode, as well as three-phase tripping and three-phase lockout. Finally, for the reliability modeling using SynerGEE, it is assumed that a non-DA recloser has a failure rate of 0.0150 faults/year, and a repair time of 4 hours, which are typical industry values.

Costs

The assumed cost of each recloser is $28,400 per location. This amount was calculated by using the values provided by the PSE cost estimation tool, and includes the material and labor costs for installing the recloser ($23,446.46), and replacing the pole ($4,931.50).

Theses reclosers are intended only for long overhead feeders. The total number of reclosers that will be installed is three for feeders with overhead exposure over 35 miles. Existing reclosers are subtracted from this amount. For example, an existing feeder with 50 miles of overhead exposure and an existing recloser, is assigned two new units.

Reliability Benefits

Based on the results of Section 6.1, the SAIDI reduction for PSE's system is assumed to be 10% per new recloser added. This is a conservative assumption that is intended to take into account a possible reduction of the effectiveness of this alternative, due to the differences between the pilot study area and PSE's system (representativeness error).

Cost-Effectiveness

No feeders in the pilot study area have an overhead exposure over 35 miles However, in order to obtain an approximate estimation of the cost-effectiveness of this alternative, feeder ING-15, which has largest overhead exposure in the pilot study area (20 miles), was analyzed. Here it is important to highlight that the average overhead exposure of the feeders in the pilot study area is 7.3 miles. As shown in Table 6-2, feeder ING-15 has a cost-effectiveness of 1.14 CMI/$, which is highest for the pilot study area. This result is expected, because reclosers are very effective for improving the reliability of long overhead distribution lines.

Using the assumptions presented in this section, the overall cost-effectiveness of this alternative for PSE's system is 1.17 CMI/$, which is very close to the value calculated for feeder ING-15 Therefore, this is a very cost-effective alternative for improving PSE's system reliability.

6.3 Option 3: New Three-Phase Manual Switches

New gang operated 3-phase manual switches were installed for each feeder in the pilot study area; class 2 poles were installed for locations where a new pole was assumed to be needed Based on the most cost-effective switch locations found in the model, we allocated two new switches for each feeder with OH exposure greater than 5 miles, plus one additional switch per 5 miles of OH exposure, with a limit of 5 new switches per feeder.

Costs (Capital and O&M)

An assumed cost of $11,400 per switch location was used based on estimates taken from the PSE estimation tool which was provided to our team. This cost includes the cost for the switch, pole replacement and the labor cost.

Table 6-5. SAIDI reduction due to the installation of new Manual Switches

#	Feeder	SAIDI Before (min)	SAIDI After (min)	SAIDI reduction (%)
1	ING15-S	151.41	136.59	10%
2	LLT16-S	218.38	191.07	13%
3	ING16-S	159.10	125.40	21%
4	WAY16-S	91.74	81.44	11%
5	KNM23-S	144.32	122.58	15%
6	WAY15-S	161.36	151.07	6%
7	KNM27-S	148.71	110.42	26%
8	NHL13-S	88.72	75.78	15%
9	WAY12-S	81.34	67.33	17%
10	NBO26-S	113.00	100.09	11%
11	LLT13-S	84.05	75.04	11%
12	WAY13-S	105.33	96.03	9%
13	NBO22-S	62.48	52.20	16%
14	LLT17-S	129.08	122.17	5%
15	HWD25-S	91.01	81.20	11%
16	KNM26-S	95.16	86.93	9%
17	VIT23-S	97.60	94.77	3%
18	HWD26-S	137.32	115.83	16%
19	ING13-S	131.72	129.4	2%
20	NHL17-S	108.41	97.38	10%
21	HWD23-S	76.58	59.69	22%
22	NHL15-S	22.76	22.23	2%
23	NBO25-S	40.18	38.89	3%
24	HWD22-S	112.29	111.84	0%
25	KNM25-S**	20.32	-	-
26	VIT16-S**	7.23	-	-
27	VIT18-S**	98.24	-	-
28	NHL16-S**	41.75	-	-
29	VIT22-S**	7.40	-	-
30	LLT15-S**	25.71	-	-
Pilot Study Area		**94.82**	**85.45**	**10%**

** Feeders where it was infeasible to install new manual switches

Reliability Benefits

The results are presented in Table 6-5, it can be seen that due to the installation of new manual switches at various locations throughout the pilot study area, SAIDI improvement ranged from 3% on some feeders to approximately 23% for some feeders. However, we found that installing new manual switches on some of the feeders (UG) were infeasible. SAIDI for the study area was reduced from approximately 95 minutes to about 86 minutes representing a reduction of approximately 10%.

Cost-Effectiveness

The cost effectiveness of installing new manual switches is summarized in Table 6-6 below. A plot showing the CMI/$ for each feeder is shown in Figure 6-2 below. Table 6-6 shows that with an estimated total capital cost of $421,800, new manual switches resulted in 0.81 CMI reduction/$ or $1.23 per customer minutes of interruption reduced. Further analysis showed that CMI reduction is approximately 5% per device added, which is based on the pilot area results and may be a bit conservative, added to that, a single new switch reduced feeder SAIDI by an average of 7.4% and three new switches reduced feeder SAIDI by an average of 21.2% for the pilot area.

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Table 6-6. CMI reduction per dollar for the installation of Switches

#	Feeder	Customers	CMI reduction	Cost ($)	CMI reduction / $
1	ING15-S	2708	40 133	11 400	3.52
2	LLT16-S	1011	27 610	11 400	2 42
3	ING16-S	1335	44 990	22 800	1 97
4	WAY16-S	1598	16 459	11 400	1 44
5	KNM23-S	1396	30 349	22 800	1.33
6	WAY15-S	1362	14 015	11 400	1 23
7	KNM27-S	1053	40 319	34 200	1.18
8	NHL13-S	2000	25 880	22 800	1 14
9	WAY12-S	816	11,432	11,400	1.00
10	NBO26-S	689	8,895	11 400	0 78
11	LLT13-S	817	7 361	11 400	0 65
12	WAY13-S	756	7,031	11 400	0.62
13	NBO22-S	1316	13,528	22 800	0 59
14	LLT17-S	883	6,102	11 400	0 54
15	HWD25-S	1224	12 007	22,800	0.53
16	KNM26-S	1420	11,687	22 800	0.51
17	VIT23-S	1963	5,555	11 400	0 49
18	HWD26-S	574	12,335	34 200	0 36
19	ING13-S	1615	3 747	11 400	0 33
20	NHL17-S	548	6 044	22 800	0 27
21	HWD23-S	524	8 850	34 200	0 26
22	NHL15-S	2664	1 412	11 400	0.12
23	NBO25-S	872	1,125	11 400	0.10
24	HWD22-S	1339	603	11 400	0.05
25	KNM25-S**	1900	-	-	-
26	VIT16-S**	871	-	-	-
27	VIT18-S**	129	-	-	-
28	NHL16-S**	1885	-	-	-
29	VIT22-S**	133	-	-	-
30	LLT15-S**	1073	-	-	-
Pilot Study Area		**36474**	**341,761**	**421,800**	**0.81**

** Feeders were it was infeasible to install new manual switches

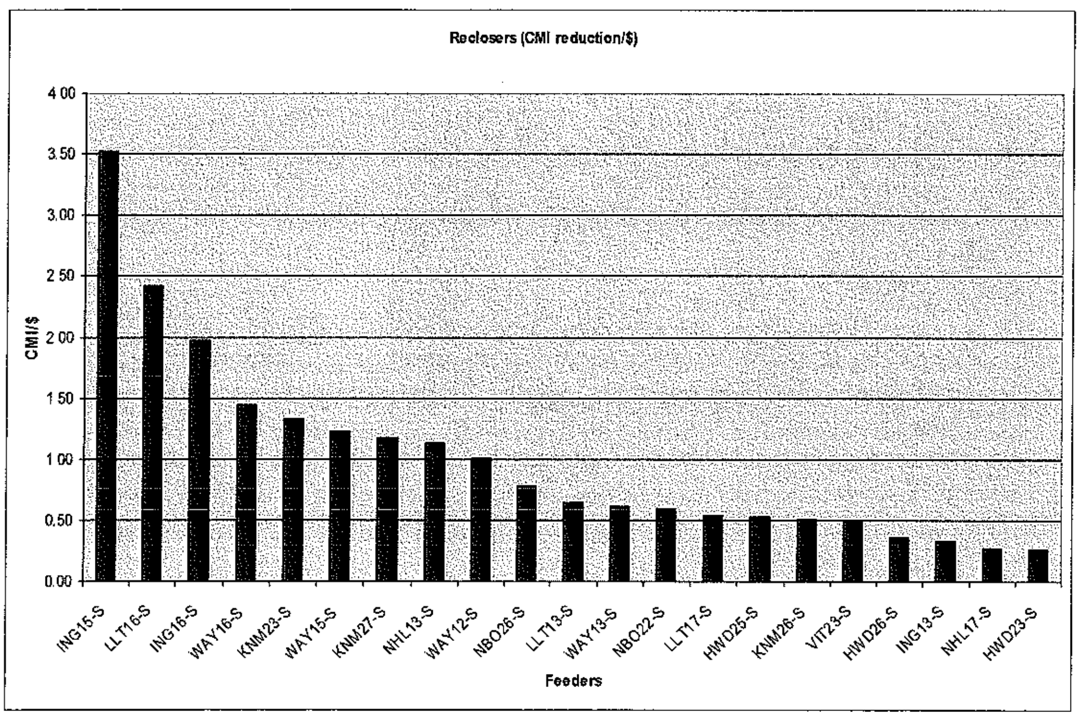

Figure 6-2. CMI/$ for each feeder due to the installation of New Manual Switches

6.4 Option 4: New Overhead and Underground SCADA Switches

New OH and UG SCADA switches were modeled at different locations, installing them on new Class 2 poles, assumed to replace an existing pole or in locations with existing manual pad mounted switchgear. These SCADA switches equipped with communications capabilities are able to improve reliability by allowing faults to be isolated and customer service restored promptly by rapidly opening and/or closing after a fault occurs. These devices were assumed to be identical to the new SCADA reclosers, but operated with the reclosing functions disabled. This approach for modeling SCADA switches allowed for flexible and robust distribution automation. Also, for modeling purposes, 1.5 new units were added to all feeders where new DA Reclosers were installed, in effect, simulating a normally-closed switch plus a normally-open tie switch shared between two feeders.

Costs (Capital and O&M)

An assumed cost of $38,400 for OH and $77,400 for UG (a new VISTA-10 with a new vault for all locations) was used based on estimates taken from the PSE estimation tool which was provided to our team. This cost includes the cost for the switch, pole replacement, new vault, labor cost plus additional $10,000 added for communication equipment.

Reliability Benefits

The results are presented in Table 6-7 below, it can be seen that due to the installation of new OH and UG SCADA switches at various locations through out the pilot study area, SAIDI improvement ranged from 6% on some feeders to approximately 37% on some feeders. However, we found that installing SCADA switches on one of the feeders (UG) were infeasible. SAIDI for the study area was reduced from approximately 95 minutes to about 78 minutes representing a reduction of approximately 18%.

Table 6-7. SAIDI reduction due to the installation of new SCADA Switches

#	Feeder	SAIDI Before	SAIDI After	SAIDI reduction (%)
1	ING15-DAS	151.41	118.41	22%
2	LLT16-DAS	218.38	147 38	33%
3	ING16-DAS	159 10	111.21	30%
6	KNM27-DAS	148.71	103 59	30%
4	WAY15-DAS	161.36	119.97	26%
5	ING13-DAS	131.72	105.62	20%
7	VIT23-DAS	97.60	79.28	19%
8	KNM23-DAS	144 32	123.64	14%
11	LLT17-DAS	129 08	104 55	19%
9	WAY13-DAS	105.33	80.1	24%
10	WAY16-DAS	91.74	79 83	13%
13	KNM25-DAS	20.32	12 85	37%
14	HWD25-DAS	91.01	80 88	11%
15	NBO26-DAS	113.00	95.84	15%
16	NHL13-DAS	88.72	83.23	6%
17	HWD26-DAS	137.32	118.44	14%
18	NBO22-DAS	62.48	54 45	13%
19	LLT13-DAS	84.05	72 08	14%
12	NHL15-DAS	22 76	16 64	27%
23	LLT15-DAS	25 71	14.22	45%
20	KNM26-DAS	95.16	86.87	9%
21	NHL17-DAS	108.41	92 68	15%
22	HWD23-DAS	76.58	61 96	19%
27	NHL16-DAS	41 75	35.24	16%
24	WAY12-DAS	81 34	75 67	7%
25	NBO25-DAS	40.18	35.83	11%
26	HWD22-DAS	112.29	110.84	1%
29	VIT18-DAS	98.24	82.64	16%
28	VIT16-DAS	7 23	7.23	0%
30	VIT22-DAS**	7.40	-	-
Pilot Study Area		**94.82**	**77.60**	**18%**

** Feeders where DA switches were not cost effective

Cost-Effectiveness

The cost effectiveness of installing new OH and UG SCADA switches are summarized in Table 6-8 below. A plot showing the CMI/$ for each feeder is shown in Figure 6-3 below. Table 6-8 shows that with an estimated total capital cost of approximately $1.8M, SCADA switches resulted in 0.34 CMI reduction/$ or $2.94 per customer minutes of interruption reduced. Further analysis showed CMI reduction to be 15% per feeder affected, the analysis also showed that a 1 5 switch SCADA scheme resulted in an average of about 18% reduction for the pilot study area.

Table 6-8. CMI reduction per dollar for the installation of new SCADA Switches

#	Feeder	Customers	CMI reduction	Cost ($)	CMI reduction / $
1	ING15-DAS	2708	89 364	57 600	1 55
2	LLT16-DAS	1011	71 781	57 600	1 25
3	ING16-DAS	1335	63 933	57 600	1 11
6	KNM27-DAS	1053	47 511	57 600	0 82
4	WAY15-DAS	1362	56 373	76 800	0.73
5	ING13-DAS	1615	42 152	57 600	0.73
7	VIT23-DAS	1963	35 962	57 600	0.62
8	KNM23-DAS	1396	28 869	57 600	0.50
11	LLT17-DAS	883	21 660	57 600	0 38
9	WAY13-DAS	756	19 074	57 600	0 33
10	WAY16-DAS	1598	19 032	57 600	0 33
13	KNM25-DAS	1900	14 193	57 600	0 25
14	HWD25-DAS	1224	12 399	57 600	0 22
15	NBO26-DAS	689	11 823	57 600	0.21
16	NHL13-DAS	2000	10 980	57 600	0.19
17	HWD26-DAS	574	10 837	57 600	0 19
18	NBO22-DAS	1316	10,567	57 600	0 18
19	LLT13-DAS	817	9,779	57 600	0 17
12	NHL15-DAS	2664	16 304	96 300	0 17
23	LLT15-DAS	1073	12 329	76 800	0 16
20	KNM26-DAS	1420	11,772	76 800	0 15
21	NHL17-DAS	548	8 620	57 600	0 15
22	HWD23-DAS	524	7,661	57,600	0.13
27	NHL16-DAS	1885	12,271	116,100	0.11
24	WAY12-DAS	816	4 627	57 600	0 08
25	NBO25-DAS	872	3 793	57 600	0 07
26	HWD22-DAS	1339	1 942	38,400	0 05
29	VIT18-DAS	129	2 012	116,100	0 02
28	VIT16-DAS	871	0	38 700	0 00
30	VIT22-DAS**	133	-	-	-
Pilot Study Area		**36474**	**628,082**	**1,845,600**	**0.34**

** Feeders where DA switches were not cost effective

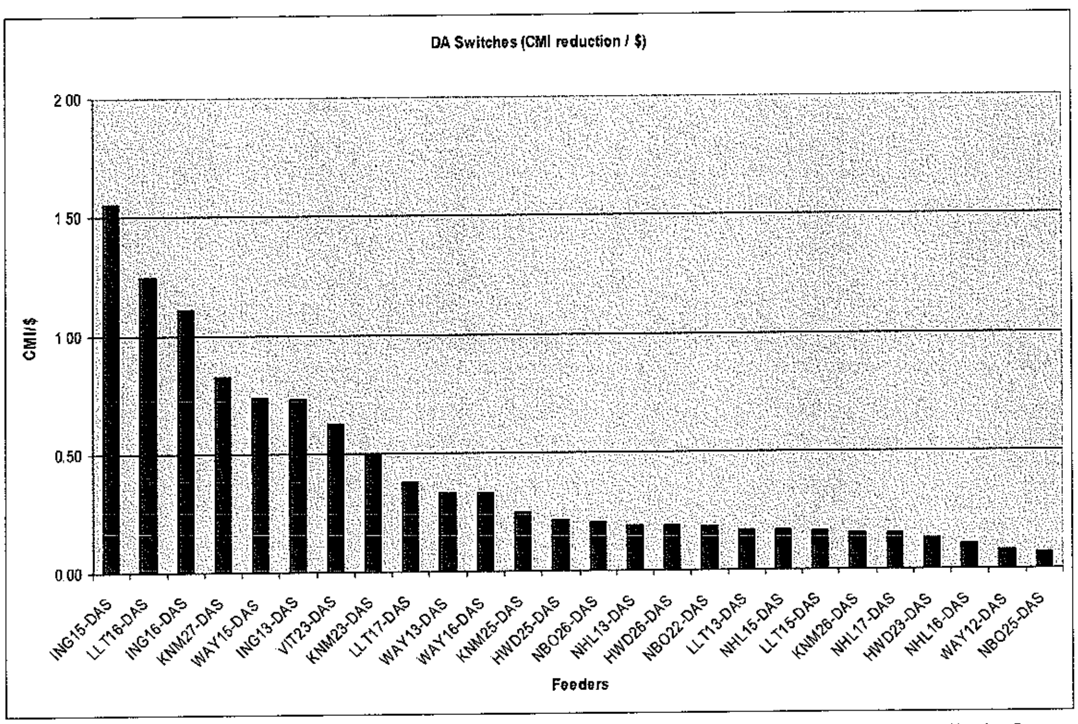

Figure 6-3. CMI/$ for each feeder due to the installation of New SCADA Switches

6.5 Option 5: Animal Guards

This alternative entails the installation of bird and animal guards (bushing covers) on overhead equipment (distribution transformers, protective and switching devices, etc).

Costs

The cost of this alternative per feeder is assumed to be $10,000. This is based on a cost of $50 per location and 200 locations per feeder, and includes the material and labor costs. Only feeders with an overhead exposure of more than 40% are selected for animal guard installation.

Reliability Benefits

Table 6-9 shows the reliability improvements obtained by implementing the "bird and animal guards" alternative for the pilot study area. The total benefits of this alternative are based on PSE's historical animal-related outages, with an assumption that 37% of these failures can be eliminated by installing "bird and animal guards". For the pilot study area, which has an overhead exposure of 36%, this assumption implies a reduction of 5% of the failure rates of overhead lines, and an average SAIDI reduction of 3 5%.

Table 6-9. SAIDI reduction of the "bird and animal guards" alternative

#	Feeder	SAIDI Before	SAIDI After	SAIDI reduction (%)
1	ING15-BA	151 41	145.00	4 23%
2	WAY15-BA	161 36	154 21	4 43%
3	LLT16-BA	203 51	195 22	4.07%
4	KNM23-BA	144 32	138.44	4 07%
5	ING13-BA	131 72	126 89	3.67%
6	ING16-BA	159.10	154 10	3 14%
7	KNM27-BA	148.71	142.65	4 08%
8	KNM26-BA	94 58	90 52	4 29%
9	WAY16-BA	91.74	88.37	3.67%
10	NHL13-BA	88.72	86.39	2.63%
11	HWD22-BA	112.29	108.92	3.00%
12	HWD25-BA	91.01	87.78	3.55%
13	NBO26-BA	113.00	108.03	4.40%
14	VIT23-BA	97.60	95.97	1 67%
15	WAY13-BA	105.53	101 33	3 98%
16	HWD26-BA	137.32	132 02	3 86%
17	NBO22-BA	62 48	60.17	3 70%
18	LLT13-BA	84.05	80.85	3 81%
19	NHL17-BA	108 41	103.95	4 11%
20	LLT17-BA	129.08	126.44	2 05%
21	WAY12-BA	81 34	78 61	3.36%
22	HWD23-BA	76.58	73.85	3.56%
23	KNM25-BA	20 32	19 72	2 95%
24	NBO25-BA	40 18	39 03	2 86%
25	NHL15-BA	22 95	22 58	1 61%
26	NHL16-BA	41 75	41.42	0 79%
27	LLT15-BA	25.71	25.18	2 06%
28	VIT16-BA	7.23	7 22	0 14%
29	VIT18-BA	98 24	-	-
30	VIT22-BA	7.40	-	-
TOTAL		94.82	91.52	3.48%

The SAIDI reduction ($SAIDI_{pilot}$ = 3.5%) and overhead exposure (OH_{pilot} = 36%) of the pilot study area are used as references for computing the benefits of this alternative for PSE's system. It is assumed that the SAIDI reduction of the i-th feeder ($SAIDI_i$) is normalized based on the percentage of overhead exposure (OH_i), as shown in (1).

$$SAIDI_i = \frac{OH_i}{OH_{pilot}} \cdot SAIDI_{pilot} \qquad (1)$$

For example, for a feeder with an overhead exposure of 72%, it is assumed that the installation of "bird and animal guards" will cause a SAIDI reduction of 7%.

Cost-Effectiveness

Table 6-10 and Figure 6-4 show the results of the cost-effectiveness analysis of implementing the "bird and animal guards" alternative for the pilot study area. From the analysis of Table 6-10 it can be concluded that this alternative is cost-effective for about 30% of the feeders. However, its average cost-effectiveness for the pilot study area is 0.43 CMI/$, which is less than the threshold of 0.5 CMI/$. This is due to the fact that the pilot study area is predominantly underground (64% underground), and this alternative is effective in mostly overhead feeders. For instance, feeder ING-15 which has the largest overhead exposure of all feeders in the pilot study area also has the highest cost-effectiveness for this alternative.

Table 6-10. Cost-effectiveness of the "bird and animal guards" alternative

#	Feeder	Customers	CMI	Cost	CMI/$
1	ING15-BA	2708	17,358	10 000	1.74
2	WAY15-BA	1362	9 738	10 000	0.97
3	LLT16-BA	1011	8 381	10 000	0.84
4	KNM23-BA	1396	8 208	10 000	0.82
5	ING13-BA	1615	7 800	10 000	0.78
6	ING16-BA	1335	6 675	10 000	0.67
7	KNM27-BA	1053	6 381	10 000	0.64
8	KNM26-BA	1420	5 765	10 000	0.58
9	WAY16-BA	1598	5 385	10 000	0.54
10	NHL13-BA	2000	4 660	10 000	0.47
11	HWD22-BA	1339	4 512	10 000	0.45
12	HWD25-BA	1224	3,954	10,000	0.40
13	NBO26-BA	689	3 424	10 000	0.34
14	VIT23-BA	1963	3,200	10 000	0.32
15	WAY13-BA	756	3 175	10 000	0.32
16	HWD26-BA	574	3 042	10 000	0.30
17	NBO22-BA	1316	3 040	10 000	0.30
18	LLT13-BA	817	2 614	10 000	0.26
19	NHL17-BA	548	2 444	10 000	0.24
20	LLT17-BA	883	2 331	10,000	0.23
21	WAY12-BA	816	2 228	10 000	0.22
22	HWD23-BA	524	1 431	10 000	0.14
23	KNM25-BA	1900	1 140	10 000	0.11
24	NBO25-BA	872	1,003	10 000	0.10
25	NHL15-BA	2664	986	10 000	0.10
26	NHL16-BA	1885	622	10 000	0.06
27	LLT15-BA	1073	569	10 000	0.06
28	VIT16-BA	871	9	10 000	0.00
29	VIT18-BA	129	-	-	-
30	VIT22-BA	133	-	-	-
	TOTAL	36474	120,364	280,000	0.43

Using the assumptions presented in this section, the overall cost-effectiveness of this alternative for PSE's system is 0.98 CMI/$, which exceeds the threshold of 0.5 CMI/$. Therefore, this is a cost-effective alternative for improving PSE's system reliability.

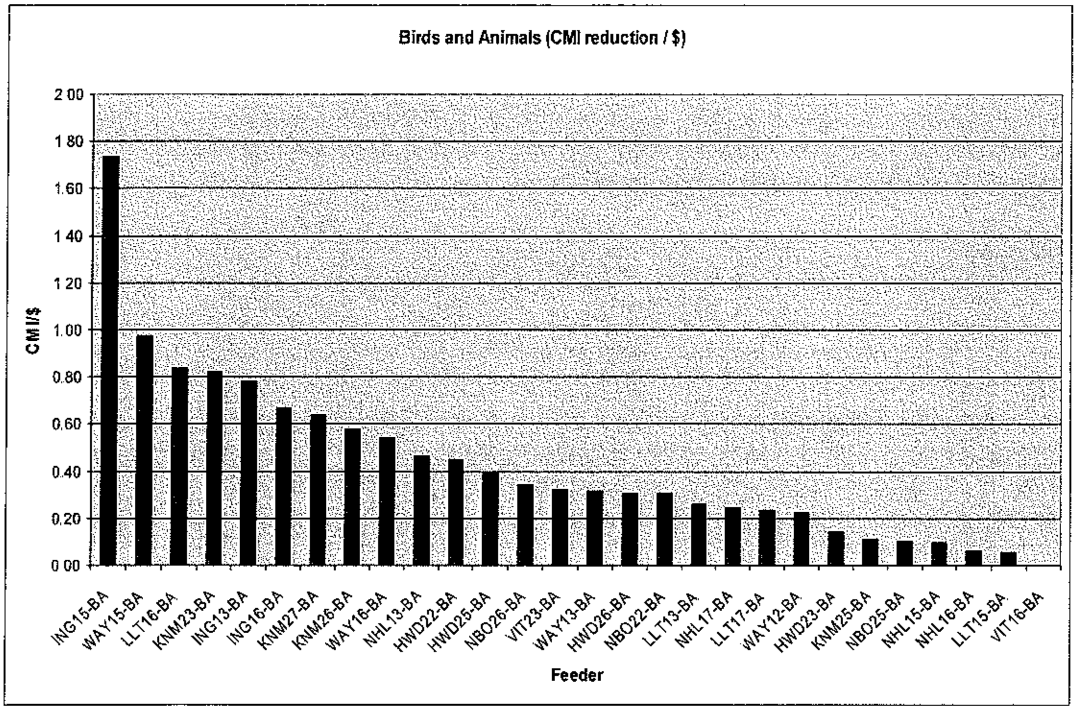

Figure 6-4. Cost-effectiveness of the "bird and animal guards" alternative

6.6 Option 6: Spacer cable

This alternative entails the replacement of bare overhead conductors with compact insulated overhead spacer cable with steel neutral used as messenger. This alternative is intended for locations where other reliability improvement alternatives are not feasible.

Costs

The cost of this alternative per mile is assumed to be $151,000. This amount was calculated by using the values provided by the PSE cost estimation tool, and includes the material and labor costs for tree-wire reconductoring.

A total of 1 mile of spacer cable is placed on the 30 feeders with highest CMI, for a total of 30 miles of spacer cable for PSE's system.

Reliability Benefits

Table 6-11 shows the reliability improvements obtained by implementing the "spacer cable" alternative for the pilot study area. The total benefits of this alternative are based on an assumed reduction of on-Right Of Way (ROW) tree failures of 75%, and an assumed reduction of off-ROW tree failures of 50%. For the pilot study area, this assumption implies a reduction of 7.6% of the failure rates of overhead lines, and an average SAIDI reduction of 3.5%.

Cost-Effectiveness

Table 6-12 and Figure 6-5 show the results of the cost-effectiveness analysis of implementing the "spacer cable" alternative for the pilot study area. From the analysis of Table 6-12 it can be concluded that this alternative is cost-effective for most feeders. The average cost-effectiveness for the pilot study area is 1.30 CMI/$, which exceeds the threshold of 0.5 CMI/$.

However, using the assumptions presented in this section, the overall cost-effectiveness of this alternative for PSE's system is 0.28 CMI/$. This is an expected result, given that this is an expensive alternative that is designed for specific locations where no other option is feasible.

Table 6-11. SAIDI reduction of the "spacer cable" alternative

#	Feeder	SAIDI Before	SAIDI After	SAIDI reduction (%)
1	ING16-SC	159.10	154.10	3 14%
2	NHL13-SC	88 72	86.39	2 63%
3	WAY16-SC	91.74	88.37	3 67%
4	KNM23-SC	144 32	138.44	4.07%
5	KNM27-SC	148 71	142 65	4 08%
6	ING15-SC	151 41	145 00	4 23%
7	WAY15-SC	161.36	154.21	4 43%
8	VIT23-SC	97.60	95.97	1 67%
9	ING13-SC	131 72	126 89	3.67%
10	LLT16-SC	203.51	195.22	4 07%
11	WAY12-SC	81 34	78 61	3.36%
12	NHL16-SC	41.75	41.42	0 79%
13	HWD26-SC	137 32	132 02	3 86%
14	WAY13-SC	105.53	101.33	3 98%
15	KNM26-SC	94.58	90.52	4 29%
16	NBO26-SC	113 00	108.03	4 40%
17	HWD22-SC	112.29	108 92	3 00%
18	NHL17-SC	108 41	103.95	4.11%
19	NBO22-SC	62 48	60.17	3 70%
20	LLT13-SC	84 05	80 85	3.81%
21	NHL15-SC	22.95	22.58	1 61%
22	LLT17-SC	129.08	126.44	2 05%
23	HWD25-SC	91 01	87 78	3.55%
24	HWD23-SC	76.58	73.85	3 56%
25	NBO25-SC	40 18	39 03	2 86%
26	KNM25-SC	20.32	19.72	2 95%
27	LLT15-SC	25.71	25.18	2 06%
28	VIT16-SC	7.23	7 22	0 14%
29	VIT18-SC	98 24	-	-
30	VIT22-SC	7.40	-	-
	TOTAL	**94.82**	**91.52**	**3.48%**

Table 6-12. Cost-effectiveness of the "spacer cable" alternative

#	Feeder	Customers	CMI	Cost	CMI/$
1	ING16-SC	1335	6 675	1 364	4 89
2	NHL13-SC	2000	4 660	1 600	2 91
3	WAY16-SC	1598	5 385	2 066	2 61
4	KNM23-SC	1396	8 208	4,040	2 03
5	KNM27-SC	1053	6,381	3 316	1.92
6	ING15-SC	2708	17,358	9 060	1 92
7	WAY15-SC	1362	9 738	5 158	1 89
8	VIT23-SC	1963	3 200	1 704	1 88
9	ING13-SC	1615	7 800	5 160	1 51
10	LLT16-SC	1011	8 381	5,657	1 48
11	WAY12-SC	816	2,228	1,513	1.47
12	NHL16-SC	1885	622	423	1.47
13	HWD26-SC	574	3 042	2 125	1 43
14	WAY13-SC	756	3 175	2 519	1 26
15	KNM26-SC	1420	5 765	5 327	1 08
16	NBO26-SC	689	3 424	3 277	1 05
17	HWD22-SC	1339	4 512	4 454	1 01
18	NHL17-SC	548	2 444	2 414	1.01
19	NBO22-SC	1316	3 040	3 772	0 81
20	LLT13-SC	817	2,614	3 604	0 73
21	NHL15-SC	2664	986	1 457	0 68
22	LLT17-SC	883	2,331	3 733	0 62
23	HWD25-SC	1224	3 954	6 683	0.59
24	HWD23-SC	524	1 431	2 505	0 57
25	NBO25-SC	872	1 003	2 026	0 49
26	KNM25-SC	1900	1,140	3 875	0 29
27	LLT15-SC	1073	569	2,689	0 21
28	VIT16-SC	871	9	730	0 01
29	VIT18-SC	129	-	-	-
30	VIT22-SC	133	-	-	-
	TOTAL	**36474**	**120,364**	**92,250**	**1.30**

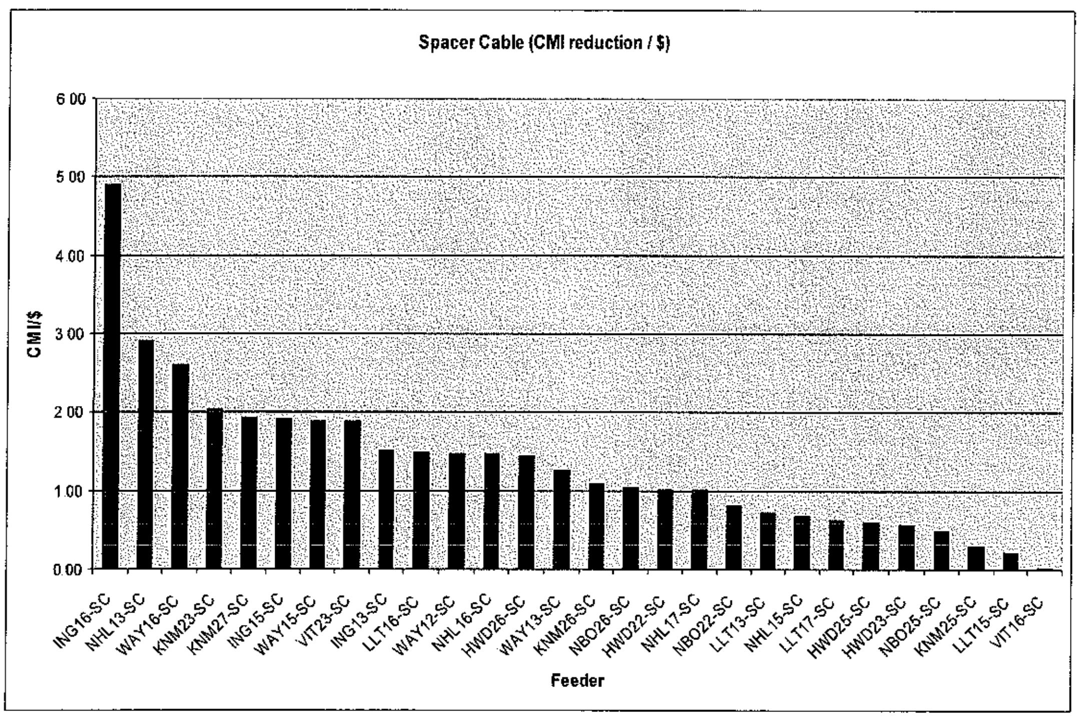

Figure 6-5. Cost-effectiveness of the "spacer cable" alternative

6.7 Option 7: New Lateral Fuses

Assuming excellent fuse coordination and operation, a fault on an unfused lateral will interrupt the customers on the entire feeder while a fault on a fused lateral will only interrupt customers on that lateral, in effect causing a decrease in the customer minutes of interruption of the customers fed by that feeder.

To model this alternative, the pilot study area model was reviewed and a total of 133 unfused laterals directly off the feeders' main trunks were identified; this represents an average of approximately 5 new fuses per feeder. Then, the reliability benefits due to the installation of new fuses in these locations were calculated. For the cost vs. reliability analysis it was assumed that the new fuses are installed on existing poles.

Here it is important to highlight that the number of unfused laterals depend on the accuracy of the pilot study area model, which might be affected by omissions during the mapping process from other information systems of PSE. It is recommended a further revision of the SynerGEE model and mapping procedure to assure that it is representative of the pilot study area.

Costs (Capital and O&M)

An assumed cost of $2000 per fuse was used based on estimates taken from the PSE estimation tool, and is a weighted average of the cost of 1f, 2f, and 3f installations. The reliability benefits and cost vs. reliability analysis for the system were calculated by assuming that 5 new fuses are installed for feeders with overhead exposure greater than 5 miles. This assumption is based on the results for the pilot study area

Reliability Benefits

The reliability benefits of fusing are presented in Table 6-13 below, it can be seen that due to the installation of new lateral fuses at various locations throughout the pilot study area, SAIDI improvement ranged from about 0.5% on some feeders to approximate 23% for some feeders. However, we found that installing fuses on some feeders (UG) were not practical or cost effective. SAIDI for the study area was reduced from approximately 95 minutes to about 89 minutes representing a reduction of approximately 6%.

Table 6-13. SAIDI reduction due to the installation of new fuses

#	Feeder	SAIDI Before (min)	SAIDI After (min)	SAIDI reduction (%)
1	ING15-F	151.41	135.30	10.6%
2	KNM27-F	148.71	137.09	7.8%
3	ING16-F	159.10	154.44	2.9%
4	ING13-F	131.72	124.14	5.8%
5	LLT16-F	203.51	177.74	12.7%
6	WAY15-F	161.36	154.99	3.9%
7	WAY16-F	91.74	86.14	6.1%
8	NBO22-F	62.48	48.63	22.2%
9	WAY13-F	105.53	93.56	11.3%
10	HWD23-F	76.58	66.73	12.9%
11	NBO26-F	113.00	101.58	10.1%
12	KNM26-F	94.58	93.08	1.6%
13	NHL13-F	88.72	86.91	2.0%
14	NHL17-F	108.41	102.99	5.0%
15	NBO25-F	40.18	36.80	8.4%
16	HWD26-F	137.32	130.54	4.9%
17	VIT23-F	97.60	97.34	0.3%
18	KNM23-F	144.32	143.37	0.7%
19	LLT17-F	129.08	126.21	2.2%
20	WAY12-F	81.34	79.72	2.0%
21	HWD25-F	91.01	86.42	5.0%
22	HWD22-F	112.29	110.86	1.3%
23	LLT13-F	84.05	83.21	1.0%
24	KNM25-F	20.32	19.58	3.6%
25	LLT15-F	25.71	25.57	0.5%
26	NHL15-F**	22.95	-	-
27	NHL16-F**	41.75	-	-
28	VIT16-F**	7.23	-	-
29	VIT18-F**	98.24	-	-
30	VIT22-F**	7.40	-	-
TOTAL		**94.82**	**89.63**	**5.47%**

** Impractical to install fuses

Cost-Effectiveness

The cost effectiveness of installing new fuses is summarized in Table 6-14 below. Also, a plot showing the CMI/$ for each feeder is shown in Figure 6-6 below. Table 6-14 shows that with an estimated total capital cost of approximately $266,000, Fuses resulted in 0.71 CMI reduction/$ or $1.4 per customer minutes of interruption reduced

Table 6-14. CMI reduction per dollar for the installation of fuses

#	Feeder	Customers	CMI reduction	Cost ($)	CMI reduction / $
1	ING15-F	2708	43,626	16,000	2.73
2	KNM27-F	1053	12,236	6,000	2.04
3	ING16-F	1335	6,221	4,000	1.56
4	ING13-F	1615	12,242	8,000	1.53
5	LLT16-F	1011	26,053	18,000	1.45
6	WAY15-F	1362	8,676	6,000	1.45
7	WAY16-F	1598	8,949	8,000	1.12
8	NBO22-F	1316	18,227	20,000	0.91
9	WAY13-F	756	9,049	10,000	0.90
10	HWD23-F	524	5,161	6,000	0.86
11	NBO26-F	689	7,868	10,000	0.79
12	KNM26-F	1420	2,130	4,000	0.53
13	NHL13-F	2000	3,620	8,000	0.45
14	NHL17-F	548	2,970	10,000	0.30
15	NBO25-F	872	2,947	10,000	0.29
16	HWD26-F	574	3,892	14,000	0.28
17	VIT23-F	1963	510	2,000	0.26
18	KNM23-F	1396	1,326	6,000	0.22
19	LLT17-F	883	2,534	14,000	0.18
20	WAY12-F	816	1,322	8,000	0.17
21	HWD25-F	1224	5,618	36,000	0.16
22	HWD22-F	1339	1,915	14,000	0.14
23	LLT13-F	817	686	6,000	0.11
24	KNM25-F	1900	1,406	16,000	0.09
25	LLT15-F	1073	150	6,000	0.03
26	NHL15-F**	2664	-	-	-
27	NHL16-F**	1885	-	-	-
28	VIT16-F**	871	-	-	-
29	VIT18-F**	129	-	-	-
30	VIT22-F**	133	-	-	-
	TOTAL	36474	189,300	266,000	0.71

** Impractical to install fuses

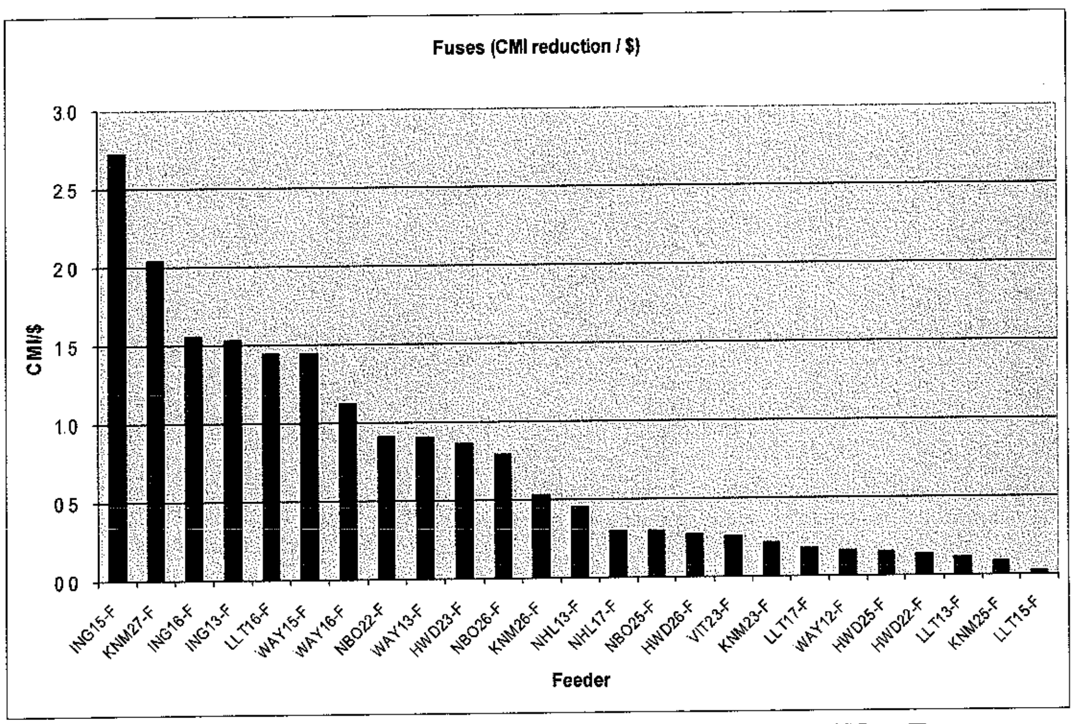

Figure 6-6. CMI/$ for each feeder due to the installation of New Fuses

6.8 Option 8: Faulted Circuit Indicators (FCI)

This alternative entails the installation of non-SCADA Faulted Circuit Indicators (FCI) on main overhead and underground trunks. The FCIs installed on overhead trunks are visible from the ground, and the FCIs installed on underground trunks are visible when the pad-mounted switchgear is inspected.

Costs

The cost of this alternative is assumed to be $400 per location. This value is based on the experience of previous analysis made by the Quanta Technology team. The reliability benefits and cost vs. reliability analysis for the pilot study area and PSE's system were calculated by assuming that the FCIs are installed in all feeders, in a total of 12 locations per feeder.

Reliability Benefits

Table 6-15 shows the reliability improvements obtained by implementing the "Faulted Circuit Indicators" alternative for the pilot study area. The total benefits of this alternative are based on an assumed average response time reduction of 15 minutes per outage event. For the pilot study area, this assumption leads to an average SAIDI reduction of 4%.

Table 6-15. SAIDI reduction of the "Faulted Circuit Indicators" alternative

#	Feeder	SAIDI Before	SAIDI After	SAIDI reduction (%)
1	ING15-FCI	151.41	144.89	4.31%
2	ING16-FCI	159.10	149.79	5.85%
3	HWD22-FCI	112.29	103.89	7.48%
4	KNM27-FCI	148.71	138.31	6.99%
5	WAY15-FCI	161.36	153.83	4.67%
6	LLT16-FCI	203.51	193.83	4.76%
7	ING13-FCI	131.72	127.21	3.42%
8	KNM23-FCI	144.32	139.90	3.06%
9	NBO22-FCI	62.48	58.01	7.15%
10	WAY13-FCI	105.53	98.64	6.53%
11	LLT17-FCI	129.08	123.25	4.52%
12	WAY16-FCI	91.74	89.67	2.26%
13	NHL16-FCI	41.75	40.04	4.10%
14	NBO26-FCI	113.00	108.40	4.07%
15	NHL17-FCI	108.41	102.65	5.31%
16	VIT23-FCI	97.60	96.09	1.55%
17	KNM26-FCI	94.58	92.52	2.18%
18	LLT13-FCI	84.05	80.94	3.70%
19	HWD26-FCI	137.32	133.20	3.00%
20	WAY12-FCI	81.34	78.58	3.39%
21	HWD25-FCI	91.01	89.31	1.87%
22	NHL13-FCI	88.72	87.77	1.08%
23	KNM25-FCI	20.32	19.37	4.68%
24	NBO25-FCI	40.18	38.75	3.56%
25	NHL15-FCI	22.95	22.50	1.96%
26	HWD23-FCI	76.58	74.64	2.53%
27	LLT15-FCI	25.71	25.10	2.37%
28	VIT18-FCI	98.24	95.02	3.28%
29	VIT16-FCI	7.23	7.04	2.63%
30	VIT22-FCI	7.40	7.27	1.76%
	TOTAL	**94.82**	**91.02**	**4.01%**

Cost-Effectiveness

Table 6-16 and Figure 6-7 show the results of the cost-effectiveness analysis of implementing the "Faulted Circuit Indicators" alternative for the pilot study area. From the analysis of Table 6-16 it can be concluded that this alternative is cost-effective for most feeders. The average cost-effectiveness for the pilot study area is 0.96 CMI/$, which exceeds the threshold of 0.5 CMI/$.

Using the assumptions presented in this section, the overall cost-effectiveness of this alternative for PSE's system is 1.13 CMI/$, which exceeds the threshold of 0.5 CMI/$. Therefore, this is a very cost-effective alternative for improving PSE's system reliability.

Table 6-16. Cost-effectiveness of the "Faulted Circuit Indicators" alternative

#	Feeder	Customers	CMI	Cost	CMI/$
1	ING15-FCI	2708	17 656	4 800	3 68
2	ING16-FCI	1335	12 429	4 800	2 59
3	HWD22-FCI	1339	11 248	4 800	2 34
4	KNM27-FCI	1053	10 951	4 800	2 28
5	WAY15-FCI	1362	10,256	4 800	2 14
6	LLT16-FCI	1011	9 786	4 800	2 04
7	ING13-FCI	1615	7 284	4 800	1 52
8	KNM23-FCI	1396	6 170	4 800	1 29
9	NBO22-FCI	1316	5 883	4 800	1 23
10	WAY13-FCI	756	5 209	4,800	1 09
11	LLT17-FCI	883	5 148	4 800	1 07
12	WAY16-FCI	1598	3 308	4 800	0 69
13	NHL16-FCI	1885	3 223	4 800	0 67
14	NBO26-FCI	689	3 169	4 800	0 66
15	NHL17-FCI	548	3 156	4 800	0 66
16	VIT23-FCI	1963	2 974	4 800	0 62
17	KNM26-FCI	1420	2 925	4 800	0 61
18	LLT13-FCI	817	2 541	4 800	0 53
19	HWD26-FCI	574	2 365	4,800	0 49
20	WAY12-FCI	816	2 252	4 800	0 47
21	HWD25-FCI	1224	2 081	4 800	0 43
22	NHL13-FCI	2000	1 910	4 800	0 40
23	KNM25-FCI	1900	1 805	4 800	0 38
24	NBO25-FCI	872	1 247	4 800	0 26
25	NHL15-FCI	2664	1 199	4 800	0 25
26	HWD23-FCI	524	1,017	4 800	0 21
27	LLT15-FCI	1073	655	4 800	0 14
28	VIT18-FCI	129	416	4 800	0 09
29	VIT16-FCI	871	165	4 800	0 03
30	VIT22-FCI	133	17	4,800	0.00
	TOTAL	**36474**	**138,601**	**144,000**	**0.96**

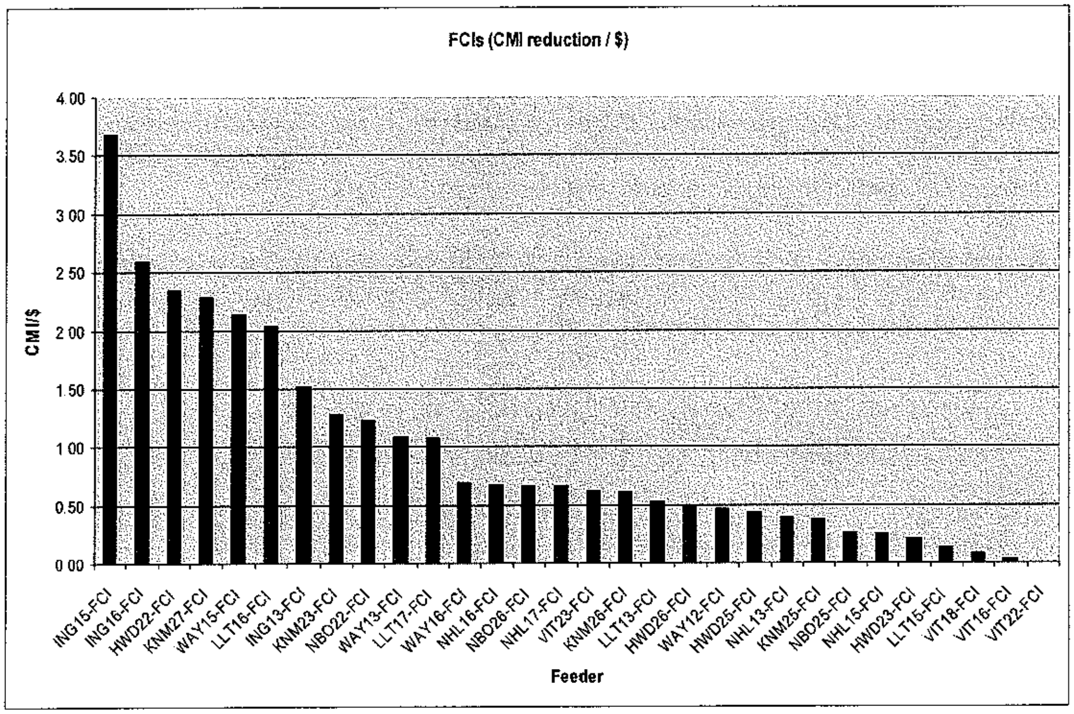

Figure 6-7. Cost-effectiveness of the "Faulted Circuit Indicators" alternative

6.9 Option 9: Overhead feeder inspections

This alternative entails the visual and infrared inspection of overhead main trunks on a five-year cycle.

Costs

The cost of this alternative is assumed to be $2200 per mile of feeder inspection, and it is based on $1100 per mile with two inspections over the ten-year period. The cost of $1100 per mile is based on actual costs for a similar US utility and includes the cost of fixing identified problems. It is assumed that 30% of all overhead exposure per feeder is main trunk, and that all of the main trunk will be inspected on a 5-year cycle.

Reliability Benefits

Table 6-17 shows the reliability improvements obtained by implementing the "overhead feeder inspections" alternative for the pilot study area. The total benefits of this alternative are based on an assumed reduction of 20% of all failure types that could potentially be prevented through an inspection program. This implies a 5% reduction of failure rates for overhead lines. For the pilot study area, which is 36% overhead, this assumption leads to an average SAIDI reduction of 5.3%

Table 6-17. SAIDI reduction of the "overhead feeder inspections" alternative

#	Feeder	SAIDI Before	SAIDI After	SAIDI reduction (%)
1	ING16-FI	159.10	151.50	4.78%
2	NHL13-FI	88.72	85.18	3.99%
3	WAY16-FI	91.74	86.62	5.58%
4	KNM23-FI	144.32	135.39	6.19%
5	KNM27-FI	148.71	139.50	6.19%
6	ING15-FI	151.41	141.66	6.44%
7	WAY15-FI	161.36	150.50	6.73%
8	VIT23-FI	97.60	95.12	2.54%
9	ING13-FI	131.72	124.39	5.56%
10	LLT16-FI	203.51	190.91	6.19%
11	WAY12-FI	81.34	77.19	5.10%
12	NHL16-FI	41.75	41.25	1.20%
13	HWD26-FI	137.32	129.26	5.87%
14	WAY13-FI	105.53	99.15	6.05%
15	KNM26-FI	94.58	88.41	6.52%
16	NBO26-FI	113.00	105.44	6.69%
17	NHL17-FI	108.41	101.63	6.25%
18	HWD22-FI	112.29	107.17	4.56%
19	NBO22-FI	62.48	58.97	5.62%
20	LLT13-FI	84.05	79.18	5.79%
21	NHL15-FI	22.95	22.38	2.48%
22	LLT17-FI	129.08	125.07	3.11%
23	HWD25-FI	91.01	86.10	5.40%
24	HWD23-FI	76.58	72.44	5.41%
25	NBO25-FI	40.18	38.43	4.36%
26	KNM25-FI	20.32	19.41	4.48%
27	LLT15-FI	25.71	24.91	3.11%
28	VIT16-FI	7.23	7.21	0.28%
29	VIT18-FI	98.24	-	-
30	VIT22-FI	7.40	-	-
	TOTAL	**94.82**	**89.81**	**5.28%**

The SAIDI reduction ($SAIDI_{pilot}$ = 5.3%) and overhead exposure (OH_{pilot} = 36%) of the pilot study area are used as references for computing the benefits of this alternative for PSE's system. It is assumed that the SAIDI reduction of the i-th feeder ($SAIDI_i$) is normalized based on the percentage of overhead exposure (OH_i), as shown in (1). For example, for a feeder with an overhead exposure of 72%, it is assumed that the implementation of this alternative will lead to a SAIDI reduction of 10.6%.

Cost-Effectiveness

Table 6-18 and Figure 6-8 show the results of the cost-effectiveness analysis of implementing the "overhead feeder inspections" alternative for the pilot study area. From the analysis of Table 6-18 it can be concluded that this alternative is cost-effective for about 30% of feeders. The average cost-effectiveness for the pilot study area is 0.41 CMI/$, which is less than the threshold of 0.5 CMI/$. This is due to the fact that the pilot study area is 36% overhead, which limits the impact of this alternative

However, using the assumptions presented in this section, the overall cost-effectiveness of this alternative for PSE's system is 1.65 CMI/$, which exceeds the threshold of 0.5 CMI/$. This is expected, given that PSE's system is 52% overhead, which increases the effectiveness of overhead feeder inspections. Therefore, it can be concluded that this is a very cost-effective alternative for improving PSE's system reliability.

Table 6-18. Cost-effectiveness of the "overhead feeder inspections" alternative

#	Feeder	Customers	CMI	Cost	CMI/$
1	ING16-FI	1335	10,146	6 625	1 53
2	NHL13-FI	2000	7 080	7,771	0 91
3	WAY16-FI	1598	8,182	10 032	0 82
4	KNM23-FI	1396	12,466	19 622	0 64
5	KNM27-FI	1053	9,698	16 103	0 60
6	ING15-FI	2708	26 403	44 000	0 60
7	WAY15-FI	1362	14,791	25,049	0 59
8	VIT23-FI	1963	4,868	8,277	0 59
9	ING13-FI	1615	11 838	25 059	0 47
10	LLT16-FI	1011	12,739	27,473	0 46
11	WAY12-FI	816	3,386	7 347	0 46
12	NHL16-FI	1885	943	2,052	0.46
13	HWD26-FI	574	4 626	10 318	0 45
14	WAY13-FI	756	4 823	12 231	0.39
15	KNM26-FI	1420	8 761	25 873	0 34
16	NBO26-FI	689	5 209	15 913	0 33
17	NHL17-FI	548	3 715	11 722	0 32
18	HWD22-FI	1339	6 856	21 631	0 32
19	NBO22-FI	1316	4 619	18 320	0 25
20	LLT13-FI	817	3 979	17,505	0.23
21	NHL15-FI	2664	1 518	7,077	0 21
22	LLT17-FI	883	3 541	18 129	0 20
23	HWD25-FI	1224	6,010	32,455	0 19
24	HWD23-FI	524	2 169	12,164	0 18
25	NBO25-FI	872	1 526	9,840	0 16
26	KNM25-FI	1900	1,729	18 817	0 09
27	LLT15-FI	1073	858	13,061	0 07
28	VIT16-FI	871	17	3 547	0 00
29	VIT18-FI	129	-	-	-
30	VIT22-FI	133	-	-	-
	TOTAL	36474	182,735	448,012	0.41

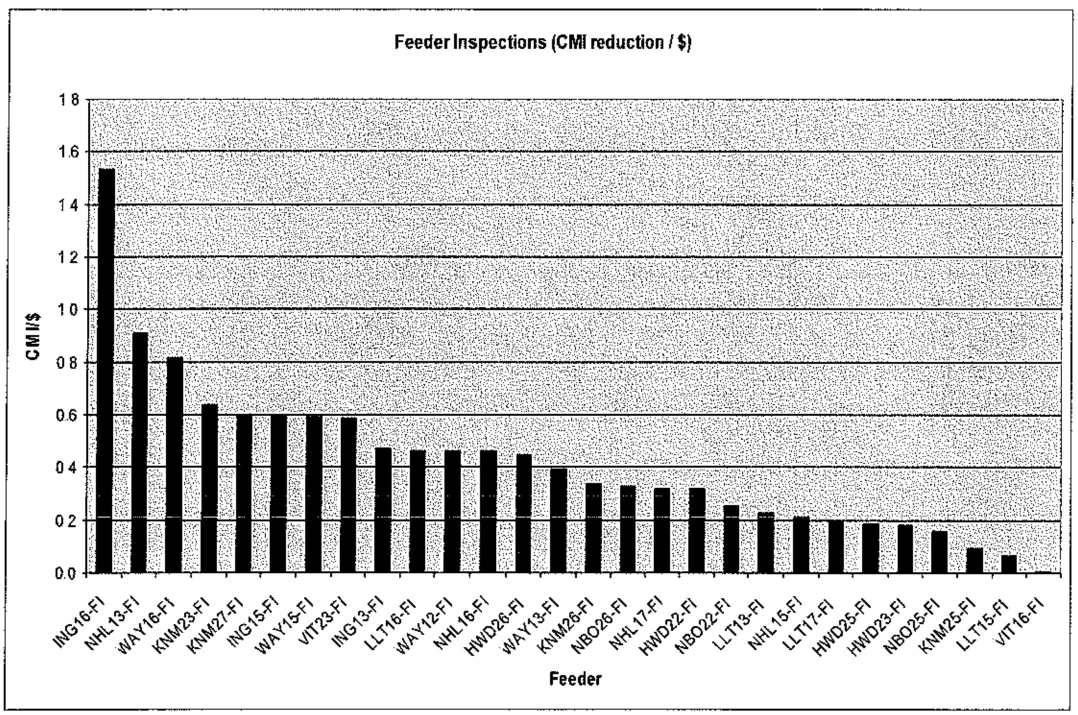

Figure 6-8. Cost-effectiveness of the "overhead feeder inspections" alternative

6.10 Option 10: Recloser Inspections

Recloser inspections include visual examination of the device, exercise of the device, and inspection of the control cabinet.

Costs (Capital and O&M)

It is assumed that the cost per recloser inspection is $250 and that 4 inspections can be completed per man-day. Recloser inspections are assumed to occur on a 3-year cycle; so there will be 3.33 inspections for each device over the ten year period. The cost of one recloser inspection over the ten year period is about $850 (the cost per inspection is multiplied by 3.33).

Table 6-19 lists the number of reclosers to be inspected in each county. These numbers include the existing reclosers, the proposed number of both new SCADA reclosers and new non-SCADA reclosers.

Table 6-19. Number of Reclosers to be Inspected

County	# of Reclosers to be Inspected
Island	21
Jefferson	22
King	192
Kitsap	87
Kittitas	29
Pierce	75
Skagit	68
Thurston	93
Whatcom	75
Total System	**662**

The 662 reclosers to be inspected in the system require a total inspection cost of about $563,000 over the ten year period.

Reliability Benefits

Recloser operational failures occur when the device is supposed to operate but fails to do so; it may degrade the feeder reliability. By performing recloser inspections, the inspected devices will operate properly more often than the uninspected devices.

The probability of operation failure for uninspected reclosers is assumed to be 6%. The inspected devices are assumed to operate properly 3% more of the time when compared to uninspected devices; i.e., the probability of operation failure for inspected reclosers is assumed to be 3%.

Figure 6-9 compares the SAIDI values of the feeders in the pilot area given all the reclosers working properly with the SAIDI values with one of the reclosers failing to operate

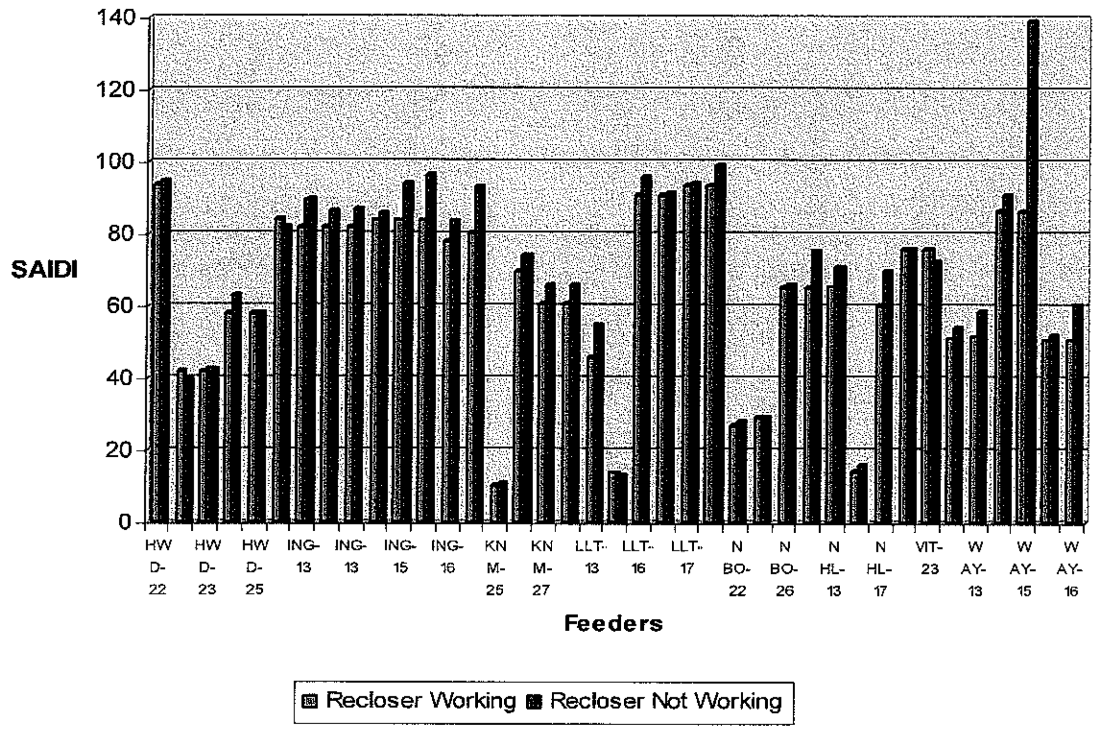

Figure 6-9. Pilot Area Feeder SAIDI while All Reclosers Working Properly and One Recloser Failing to Operate

The study on the pilot area feeders shows that recloser inspections result in an average SAIDI reduction of 0.22% per device on the model; the CMI is accordingly reduced by an average value of 0.22% per device on the model. This value is used for CMI reductions for the remainder of the system.

Cost-Effectiveness

The reliability benefits of recloser inspections only apply to the feeders with reclosers installed or to be installed. Table 6-20 lists the CMI reduction that can be achieved by recloser inspections in different counties. The achieved CMI reduction in each county is the sum of the CMI reduction in the beneficial feeders.

Table 6-20. Reliability Benefits (CMI reduction) by Recloser Inspections

County	CMI Reduction
Island	11,260
Jefferson	7,635
King	60,131
Kitsap	34,637
Kittitas	5,238
Pierce	18,864
Skagit	16,919
Thurston	42,003
Whatcom	17,697
Total System	**214,384**

In summary, recloser inspections can reduce the system CMI by 214,384 with a cost of $563,000. The $/CMI of performing recloser inspections is about 2.62, i.e., reducing 1 customer minute of interruption requires a spending of $2.62.

6.11 Option 11: Fuse saving during storms

This alternative entails remotely changing the settings of DA reclosers of Section 6.1 to "fuse saving" mode when major storms are forecasted for the PSE service territory. It is assumed that the settings of substation relays are not modified and remain in "fuse clearing" mode.

Costs

The cost of this alternative is assumed to be $1000 per new DA recloser. This includes both any necessary device settings, plus any required costs for software, integration with existing PSE's information systems, and operator training. The number of devices to be included in this alternative is equal to the number of new SCADA reclosers.

Reliability Benefits

Table 6-21 shows the reliability improvements obtained by implementing the "fuse saving during storms" alternative for the pilot study area. The SAIDI reduction values of Table 6-21 where calculated by comparing the results obtained by implementing the DA reclosers alternative in a global "fuse blowing" scheme (SAIDI Before), with the results obtained by implementing that alternative in a "fuse saving" scheme, but only for the fuses located downstream of the DA reclosers (SAIDI After). The SAIDI Before values were calculated for the 32 DA reclosers of Section 6.1.

Table 6-21. SAIDI reduction of the "fuse saving during storms" alternative

#	Feeder	SAIDI Before (min)	SAIDI After (min)	SAIDI reduction (%)
1	ING15-FS	135.27	131.52	3%
2	HWD25-FS	84.75	82.34	3%
3	ING13-FS	120.83	119.19	1%
4	WAY15-FS	140.31	138.49	1%
5	WAY12-FS	66.72	64.06	4%
6	KNM23-FS	124.32	123.19	1%
7	KNM26-FS	89.17	88.43	1%
8	NBO22-FS	50.71	50.20	1%
9	NBO26-FS	85.92	84.04	2%
10	NHL17-FS	94.78	93.66	1%
11	KNM27-FS	89.58	88.63	1%
12	LLT13-FS	67.34	66.81	1%
13	LLT16-FS	152.21	151.57	0%
14	HWD26-FS	126.34	125.83	0%
15	NHL15-FS	20.11	20.06	0%
16	WAY16-FS	64.95	64.81	0%
17	LLT17-FS	120.85	120.75	0%
18	VIT23-FS	89.45	89.38	0%
19	HWD22-FS	110.68	110.65	0%
20	WAY13-FS	81.11	81.07	0%
21	KNM25-FS	16.56	16.55	0%
22	NBO25-FS	38.22	38.19	0%
23	LLT15-FS	21.82	21.80	0%
24	HWD23-FS	67.64	67.60	0%
25	ING16-FS	130.75	130.75	0%
26	NHL13-FS	82.30	82.30	0%
27	NHL16-FS	-	41.75	-
28	VIT16-FS	-	7.23	-
29	VIT18-FS	-	98.24	-
30	VIT22-FS	-	7.4	-
Pilot Study Area		**81.56**	**80.77**	**1%**

The total benefits of this alternative are based on the assumption that that 25% of all SAIDI is due to storms where this scheme would be utilized. This assumption leads to an average SAIDI reduction of 1% per DA recloser.

Cost-Effectiveness

Table 6-22 and Figure 6-10 show the results of the cost-effectiveness analysis of implementing the "fuse saving during storms" alternative for the pilot study area. From the analysis of Table 6-22 it can be concluded that this alternative is very cost-effective for about 40% of feeders. The average cost-effectiveness for the pilot study area is 0.9 CMI/$, which exceeds the threshold of 0.5 CMI/$.

Using the assumptions presented in this section, the overall cost-effectiveness of this alternative for PSE's system is 1.71 CMI/$, which also exceeds the threshold of 0.5 CMI/$. This is expected, given that PSE's system is 52% overhead, which increases the effectiveness of using fuse saving during storms. Therefore, it can be concluded that this is a very cost-effective alternative for improving PSE's system reliability.

Table 6-22. Cost-effectiveness of the "fuse saving during storms" alternative

#	Feeder	Customers	CMI reduction	Cost ($)	CMI reduction / $
1	ING15-FS	2708	10,148	1 000	10.15
2	HWD25-FS	1224	2 947	1.000	2 95
3	ING13-FS	1615	2 653	1 000	2 65
4	WAY15-FS	1362	2 486	1 000	2 49
5	WAY12-FS	816	2 171	1 000	2 17
6	KNM23-FS	1396	1,574	1 000	1 57
7	KNM26-FS	1420	1,054	1 000	1 05
8	NBO22-FS	1316	668	1 000	0 67
9	NBO26-FS	689	1,295	2 000	0.65
10	NHL17-FS	548	615	1 000	0 62
11	KNM27-FS	1053	998	2 000	0 50
12	LLT13-FS	817	437	1 000	0 44
13	LLT16-FS	1011	647	2 000	0 32
14	HWD26-FS	574	291	1 000	0 29
15	NHL15-FS	2664	140	1 000	0 14
16	WAY16-FS	1598	228	2 000	0 11
17	LLT17-FS	883	93	1 000	0 09
18	VIT23-FS	1963	142	2 000	0 07
19	HWD22-FS	1339	44	1 000	0 04
20	WAY13-FS	756	32	1 000	0 03
21	KNM25-FS	1900	28	1 000	0 03
22	NBO25-FS	872	26	1 000	0 03
23	LLT15-FS	1073	24	1 000	0 02
24	HWD23-FS	524	21	2 000	0 01
25	ING16-FS	1335	3	1 000	0 00
26	NHL13-FS	2000	0	1 000	0.00
27	NHL16-FS	1885	-	-	-
28	VIT16-FS	871	-	-	-
29	VIT18-FS	129	-	-	-
30	VIT22-FS	133	-	-	-
Pilot Study Area		**36474**	**28,723**	**32,000**	**0.90**

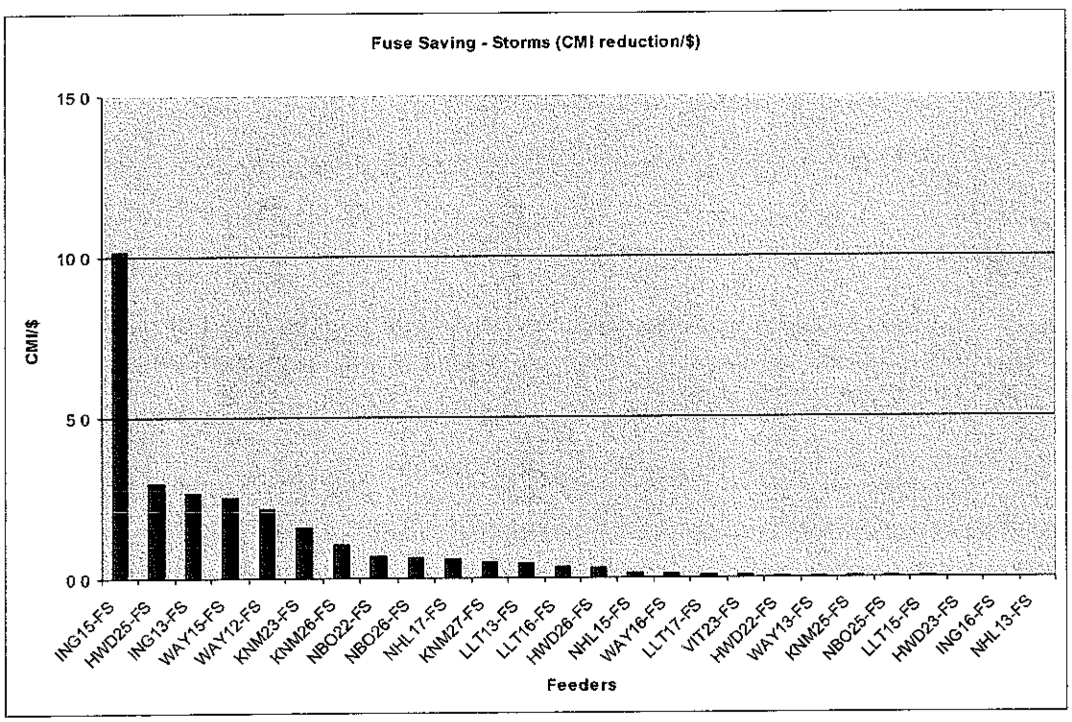

Figure 6-10. Cost-effectiveness of the "fuse saving during storms" alternative

6.12 Option 12: Underground Switch Inspections

UG switch inspections include visual examination of the device and exercise of the device.

Costs (Capital and O&M)

It is assumed that the cost per UG switch inspection is $200 and that 4 inspections can be completed per man-day. UG switch inspections are assumed to occur on a 3-year cycle; so there will be 3.33 inspections for each UG switch over the ten year period. The cost of one UG switch inspection over the ten year period is about $670 (the cost per inspection is multiplied by 3.33).

The amount of UG switches to be inspected is based on an assumed one UG switch per 7 miles of UG exposure, which is the characteristic of the pilot area. All UG switches are assumed to be included in this program. Table 6-23 lists the number of UG switches to be inspected in each county.

Table 6-23. Number of UG Switches to be Inspected

County	# of UG Switches to be Inspected
Island	49
Jefferson	34
King	602
Kitsap	146
Kittitas	41
Pierce	151
Skagit	72
Thurston	171
Whatcom	99
Total System	**1,363**

The 1,363 UG switches to be inspected in the system require a total inspection cost of about $913,000 over the ten year period.

Reliability Benefits

UG switch operational failures occur when the device is supposed to operate but fails to do so; it may degrade the feeder reliability. By performing UG switch inspections, the inspected devices will operate properly more often than the uninspected devices.

The probability of operation failure for uninspected UG switches is assumed to be 6%. The inspected devices are assumed to operate properly 3% more of the time when compared to uninspected devices; i.e., the probability of operation failure for inspected UG switches is assumed to be 3%.

Figure 6-11 compares the SAIDI values of the feeders in the pilot area given all the UG switches working properly with the SAIDI values with one of the UG switches failing to operate.

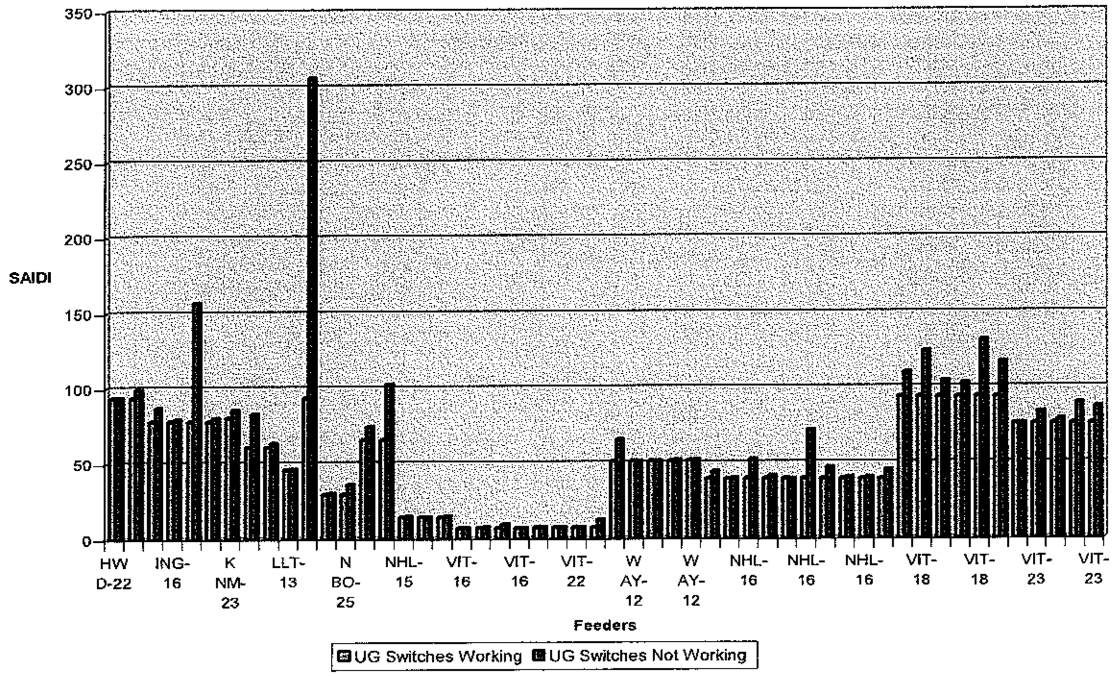

Figure 6-11. Pilot Area Feeder SAIDI while all UG Switches Working Properly and One UG Switch Failing to Operate

The study on the pilot area feeders shows that UG switch inspections result in an average SAIDI reduction of 0.57% per device on the model; the CMI is accordingly reduced by an average value of 0.57% per device on the model. This value is used for CMI reductions for the remainder of the system.

Cost-Effectiveness

Table 6-24 lists the CMI reduction that can be achieved by UG switch inspections in different counties. The CMI reduction in each county is the sum of the CMI reduction achieved in the beneficial feeders.

Table 6-24. Reliability Benefits (CMI reduction) by UG Switch Inspections

County	CMI Reduction
Island	85,488
Jefferson	73,560
King	662,580
Kitsap	338,994
Kittitas	44,231
Pierce	152,856
Skagit	98,346
Thurston	471,983
Whatcom	104,471
Total System	**2,032,509**

In summary, UG switch inspections can reduce the system CMI by 2,032,509 with a cost of $913,000. The $/CMI of performing UG switch inspections is about 0.45, i.e., reducing 1 customer minute of interruption only requires a spending of $0.45.

6.13 Option 13: Overhead SCADA Switch Inspections

OH SCADA switch inspections include visual examination of the device, exercise of the device, and inspection of the control cabinet.

Costs (Capital and O&M)

It is assumed that the cost per OH SCADA switch inspection is $250 and that 4 inspections can be completed per man-day. OH SCADA switch inspections are assumed to occur on a 3-year cycle; so there will be 3.33 inspections for each device over the ten year period. The cost of one OH SCADA switch inspection over the ten year period is about $850 (the cost per inspection is multiplied by 3.33).

There are currently no OH SCADA switches installed in the system. The amount of OH SCADA switches to be inspected is equal to the number of new OH SCADA switches to be installed. Table 6-25 lists the number of OH SCADA switches to be inspected in each county.

Table 6-25. Number of OH SCADA Switches to be Inspected

County	# of OH SCADA Switch to be Inspected
Island	6
Jefferson	5
King	84
Kitsap	41
Kittitas	3
Pierce	36
Skagit	21
Thurston	30
Whatcom	36
Total System	**262**

The 262 OH SCADA switches to be inspected in the system require a total inspection cost of about $223,000 over the ten year period.

Reliability Benefits

Since there are currently no OH SCADA switches (essentially), no incremental benefit is assumed for this activity. However, if this activity is not performed, the benefits of the new devices will decline over time.

6.14 Option 14: Underground SCADA Switch Inspections

UG SCADA switch inspections include visual examination of the device, exercise of the device, and inspection of the control cabinet.

Costs (Capital and O&M)

It is assumed that the cost per UG SCADA switch inspection is $250 and that 4 inspections can be completed per man-day. UG SCADA switch inspections are assumed to occur on a 3-year cycle; so there will be 3.33 inspections for each device over the ten year period. The cost of one UG SCADA switch inspection over the ten year period is about $850 (the cost per inspection is multiplied by 3.33).

Here it is assumed that the total amount of UG SCADA switches to be inspected is equal to the number of new UG SCADA switches to be installed. Table 6-26 lists the number of UG SCADA switches to be inspected in each county.

Table 6-26. Number of UG SCADA Switches to be Inspected

County	# of UG SCADA Switches to be Inspected
Island	3
Jefferson	8
King	60
Kitsap	14
Kittitas	9
Pierce	20
Skagit	12
Thurston	23
Whatcom	3
Total System	**150**

The 150 UG SCADA switches to be inspected in the system require a total inspection cost of about $128,000 over the ten year period.

Reliability Benefits

Since there are currently no UG SCADA switches (essentially), no incremental benefit is assumed for this activity. However, if this activity is not performed, the benefits of the new devices will decline over time

6.15 Option 15: Circuit Segmentation

The PSE storm hardening plan called for added overhead sectionalizing switches for increased "circuit segmentation" capability during storms Since the reliability roadmap already assumes a large number of new sectionalizing switches for this purpose, these components of the hardening plan are no longer necessary.

Costs (Capital and O&M)

The PSE storm hardening plan calls for $12,384,000 for installing solid blade cutouts on primary laterals between fuses. It also calls for $15,480,000 for installing switches on primary feeder. These costs are no longer necessary if the new OH switch program in the reliability roadmap is undertaken

Reliability Benefits

n/a

Cost-Effectiveness

n/a

6.16 Option 16: Critical Pole Hardening

When more equipment is added to a pole, or when this pole is being used jointly by multiple companies, the loading on that pole increases, and then the pole starts to approach its maximum loading capacity. This reduces the pole's resistance to extreme winds, as the tensile strength of the pole is reduced. Quanta Technology recommends that an additional item be added to the PSE storm hardening plan This includes replacing the poles at locations where major equipments are installed. These upgraded poles are unlikely to break during extreme wind or major storm conditions. Major equipment poles include reclosers, switches, cap banks, automated devices, CellNet collectors, communication, cable devices and freeway crossings

Costs (Capital and O&M)

Based on the pilot area analysis, a typical feeder currently has an average of 6 critical equipment poles. Assuming an addition of at least one recloser per feeder, this would result in an average of at least 6 pole upgrades per feeder

A cost of $4900 per location is based on PSE cost model for 40' Class 2 pole replacement. This estimate is conservative, because storm guying and/or pole reinforcement can probably be used in certain cases.

Reliability Benefits

A SAIDI impact analysis was not done for this option

Cost-Effectiveness

No incremental cost is assumed.

6.17 Option 17: Pole Test and Test Treatment

Fungi, termites, ants, wood borers and other low forms of plant life causes wood poles to gradually deteriorate resulting in pole decay. This causes a considerable reduction in the service life of the pole. In some cases the decay takes place below the groundline where conditions of moisture, temperature and air are most favorable for growth of fungi making it difficult to see (incipient decay). This phenomenon usually takes place in creosote and pentachlorophenol treated poles. Wood pole service life can be greatly increased by combining the proper application of effective remedial treatments with a pole inspection program.

The vulnerability of poles to decay is generally proportionate to the decay zone in which they are installed. Looking at the map of decay zones originally developed by Rural Electrification Administration (REA), it is apparent that PSE is located somewhere in zone 4. Based on this; Quanta Technology recommends that PSE pursue a wood pole test-and-treat program on a 10-year cycle. These estimates are for distribution poles only. After testing, acceptable poles are treated. Rejected poles are then assessed to determine whether they are overloaded. If overloaded, poles that can be reinforced are reinforced and are otherwise replaced.

Costs (Capital and O&M)

Based on 10,557 miles of OH and an assumed span length of 150 feet, it is assumed that PSE has 369,495 wood distribution poles and that 10% of these will be inspected per year. Assumed initial rejection rate is 4%, and that 3% need action after the loading assessment. It is further assumed that 50% of poles requiring work can be reinforced, and the remainder replaced.

Cost is $35 per test-and-treat, $25 per pole loading calculation, $550 per reinforcement, and $4800 for replacement. Total cost per year is $4,295,379. This cost is multiplied by ten for inclusion in the roadmap cost.

Reliability Benefits

A SAIDI impact analysis was not done for this option.

Cost-Effectiveness

No incremental cost is assumed.

6.18 Option 18: Substation Automation

The project of substation automation assumes that feeder breakers not currently equipped with SCADA become equipped with SCADA so that they can be remotely opened and closed

Costs (Capital and O&M)

Substation automation is being done through another budget, therefore no incremental cost is assumed. The number of feeders to be automated is equal to the number of existing feeder breakers that do not have SCADA.

Reliability Benefits

Once the feeder breakers are equipped with SCADA, they can be remotely opened and closed. It can expedite the restoration and then reduce the SAIDI since crews do not have to drive back to substation in order to reset breakers. The switching times are assumed to reduce by 15 minutes.

Figure 6-12 compares the SAIDI values of the feeders in the pilot area without substation automation and with substation automation.

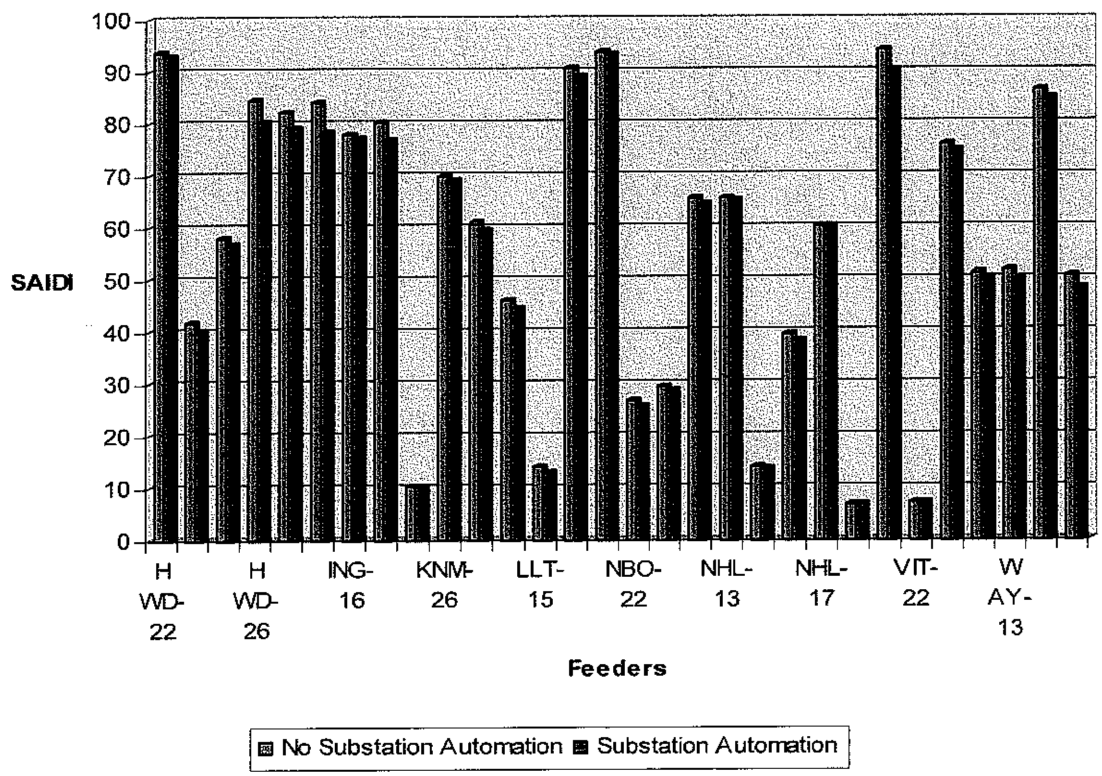

Figure 6-12. Pilot Area Feeder SAIDI without substation automation and with substation automation

The study on the pilot area shows that substation automation results in an average SAIDI reduction of 2.6% per feeder on the model; the CMI is accordingly reduced by an average value of 2.6% per feeder on the model. This value is used for CMI reductions for the remainder of the system.

Cost-Effectiveness

The reliability benefits of substation automation apply to the feeders in which the breakers currently are not equipped with SCADA. Table 6-27 lists the CMI reduction that can be achieved by substation automation in different counties. The CMI reduction achieved in each county is the sum of the CMI reduction in the beneficial feeders.

Table 6-27. Reliability Benefits (CMI reduction) by Substation Automation

County	CMI Reduction
Island	6,191
Jefferson	0
King	80,770
Kitsap	15,112
Kittitas	14,774
Pierce	14,737
Skagit	15,947
Thurston	0
Whatcom	148,312
Total System	**295,844**

Since the substation automation is being done through another budget and no incremental cost is assumed, the $/CMI value is not calculated.

6.19 Option 19: Improved Fuse Coordination

The fuse coordination improving project assumes that fuses will increase their likelihood of being properly coordinated so that the protection device closest to a fault will clear the fault.

Costs (Capital and O&M)

Fuse coordination improvement is being done through another budget, therefore no incremental cost is assumed. The number of feeders to be worked on is equal to the number of existing feeder breakers that do not have SCADA.

Reliability Benefits

Improved fuse coordination may lead to less affected customers by an outage and then improve the system reliability by reducing the SAIDI value.

The fuse miscoordination is assumed to happen at a probability of 10% before the coordination study. It is assumed that miscoordination happens 7% less often after the study, i.e., the probability of fuse miscoordination is 3% after the study.

Due to the large amount of fuses in the model, the effect of improved fuse coordination in a sample set of the fuses in the pilot area feeders is studied. The study shows that improved fuse coordination results in an average SAIDI reduction of 7.3% per feeder on the model; the CMI is accordingly reduced by an average value of 7.3% per feeder on the model. This value is used for CMI reductions for the remainder of the system.

Cost-Effectiveness

Table 6-28 lists the CMI reduction that can be achieved by improved fuse coordination in different counties.

Table 6-28. Reliability Benefits (CMI reduction) by Improved Fuse Coordination

County	CMI Reduction
Island	374,852
Jefferson	457,918
King	4,301,259
Kitsap	2,113,697
Kittitas	142,620
Pierce	712,074
Skagit	615,963
Thurston	1,450,683
Whatcom	859,419
Total System	**11,028,484**

Since the fuse coordination improvement is being done through another budget and no incremental cost is assumed, the $/CMI value is not calculated.

6.20 Option 20: Mobile Workforce Management

This project assumes that PSE first responder truck are outfitted with mobile computers and GPS (Global Positioning System is a satellite-based radio navigation system that provides latitude and longitude information) trackers that are integrated with the new outage management system. One of the greatest built-in cost savings that may be derived from a Global Utility Tracking Systems is the streamlining of procedures and the elimination of paperwork for the crews. Construction drawings, as-builts, or plats can be easily scanned and geo-coded, or exported from engineering's CAD or GIS system. Huge savings in manpower hours can be realized by better organizing and efficiently routing duties, due to crews eliminating trips back and forth to the office to pick up paperwork, and provide the most current maps and documentation to those who need it most. This can be very helpful, especially in cases where a large portion of the crew work is outsourced or in storm situations where foreign crews are used for restoration efforts.

Costs (Capital and O&M)

This is being done through another budget. No incremental cost is assumed.

Reliability Benefits

The SAIDI benefits of mobile work management system are presented in Table 6-29 below, it can be seen that due to the placement of mobile work management system in crew trucks, SAIDI improvement ranged from about 0.4% on some feeders to approximate 2.5% for some feeders. SAIDI for the study area was reduced from approximately 95 minutes to about 93.545 minutes, representing a reduction of approximately 1.4% To model this phenomenon we assumed that equipping crews with mobile laptops and GPS systems would reduced outage response time by about 5 minutes.

Table 6-29. SAIDI reduction due to the implementations of Mobile WMS

#	Feeder	SAIDI Before	SAIDI After	SAIDI reduction (%)
1	HWD22-WMS	112.29	109.50	2.48%
2	HWD23-WMS	76 58	75.89	0.90%
3	HWD25-WMS	91.01	90.46	0.60%
4	HWD26-WMS	137.32	135 89	1 04%
5	ING13-WMS	131.72	130 21	1.15%
6	ING15-WMS	151.41	149 24	1.43%
7	ING16-WMS	159.10	155.92	2.00%
8	KNM23-WMS	144.32	142.78	1 07%
9	KNM25-WMS	20 32	19.99	1 62%
10	KNM26-WMS	94.58	93.92	0 70%
11	KNM27-WMS	148.71	145.02	2 48%
12	LLT13-WMS	84.05	83.05	1 19%
13	LLT15-WMS	25.71	25.51	0.78%
14	LLT16-WMS	203 51	200.13	1 66%
15	LLT17-WMS	129.08	127.09	1.54%
16	NBO22-WMS	62 48	61 05	2 29%
17	NBO25-WMS	40.18	39.69	1 22%
18	NBO26-WMS	113.00	111.53	1 30%
19	NHL13-WMS	88 72	88.41	0 35%
20	NHL15-WMS	22 95	22 81	0 61%
21	NHL16-WMS	41.75	41.20	1 32%
22	NHL17-WMS	108.41	106.43	1 83%
23	VIT16-WMS	7.23	7.17	0.83%
24	VIT18-WMS	98 24	97.20	-
25	VIT22-WMS	7.40	7.36	-
26	VIT23-WMS	97 60	97 10	0 51%
27	WAY12-WMS	81.34	80.39	1 17%
28	WAY13-WMS	105.53	103.33	2 08%
29	WAY15-WMS	161.36	158.83	1 57%
30	WAY16-WMS	91.74	91.02	0.78%
	TOTAL	**94.82**	**93.54**	**1.35%**

Cost-Effectiveness

n/a

Other benefits

With the correct hardware in place and a mobile GIS platform, a new method of conducting joint-use surveys maybe derived for Puget Sound Energy. The ability to collect joint-use data and GPS coordinates in the field using mobile technology improved on old methods can now enable PSE to update and maintain joint-use data more effectively with the use of GIS. Joint-use in this case means situations where multiple companies use or share the same pole.

6.21 Integrated Solution

This alternative entails the combined implementation of several alternatives. For this analysis, the following alternatives have been analyzed: new three-phase DA reclosers, new three-phase manual switches, new underground DA switches, new overhead DA switches, bird and animal guards, spacer cable, new lateral fuses, Faulted Circuit Indicators, overhead feeder inspections, and mobile workforce management

Costs

The assumed total cost for implementing this alternative for the pilot study area is $ 4,726,461. This amount was calculated by adding up the total costs of implementing each of the individual alternatives considered in this joint solution.

Reliability Benefits

Table 6-30 and Figure 6-13 show the reliability improvements obtained by implementing the "integrated solution" for the pilot study area. The SAIDI reduction values of Table 6-30 were calculated by comparing the base case (current situation), with the reliability improvements due to the "integrated solution". Here it is important to highlight that the total SAIDI reduction of 44.20% exceeds the target value of 39.8% defined for the pilot study area, which is part of King County.

Table 6-30. SAIDI reduction due to the implementation of the "integrated solution"

#	Feeder	SAIDI Before (min)	SAIDI After (min)	SAIDI reduction (min)	SAIDI reduction (%)
1	Ing15	151 41	77 28	74 13	48.96%
2	Ing16	159.10	74 40	84 70	53.24%
3	Way15	161 36	78 14	83 22	51.57%
4	Ing13	131.72	71 25	60.47	45.91%
5	Knm23	144.32	74.38	69.94	48.46%
6	LLT16	203.51	83.16	120.35	59 14%
7	Knm27	148.71	55.80	92 91	62 48%
8	Way16	91.74	47 80	43.94	47 90%
9	NHL13	88.72	63.17	25 55	28 80%
10	Way13	105 53	47 47	58 06	55 02%
11	Nbo22	62 48	25 06	37 42	59 89%
12	Vit23	97.60	74 08	23 52	24.10%
13	Hwd22	112.29	87 44	24 85	22 13%
14	Knm26	94 58	64.38	30 20	31.93%
15	LLT13	84.05	42 47	41 58	49.47%
16	LLT17	129.08	89.65	39 43	30.55%
17	Hwd25	91.01	53.83	37 18	40 85%
18	Hwd26	137.32	78.54	58.78	42 81%
19	Way12	81.34	48.12	33.22	40 84%
20	Nbo26	113 00	60 09	52 91	46 82%
21	NHL17	108.41	55 11	53.30	49 17%
22	NHL15	22 95	13.65	9.30	40 52%
23	Knm25	20 32	9.80	10.52	51 77%
24	NHL16	41 75	32 97	8.78	21 03%
25	Hwd23	76.58	36 20	40 38	52.73%
26	LLT15	25.71	13.46	12 25	47.65%
27	Nbo25	40.18	27.88	12 30	30.61%
28	Vit18	98.24	78.44	19.80	20.15%
29	VIT22	7 40	7 23	0.17	2 30%
30	Vit16	7.23	6.95	0.28	3.87%
System		**94.82**	**52.91**	**41.91**	**44.20%**

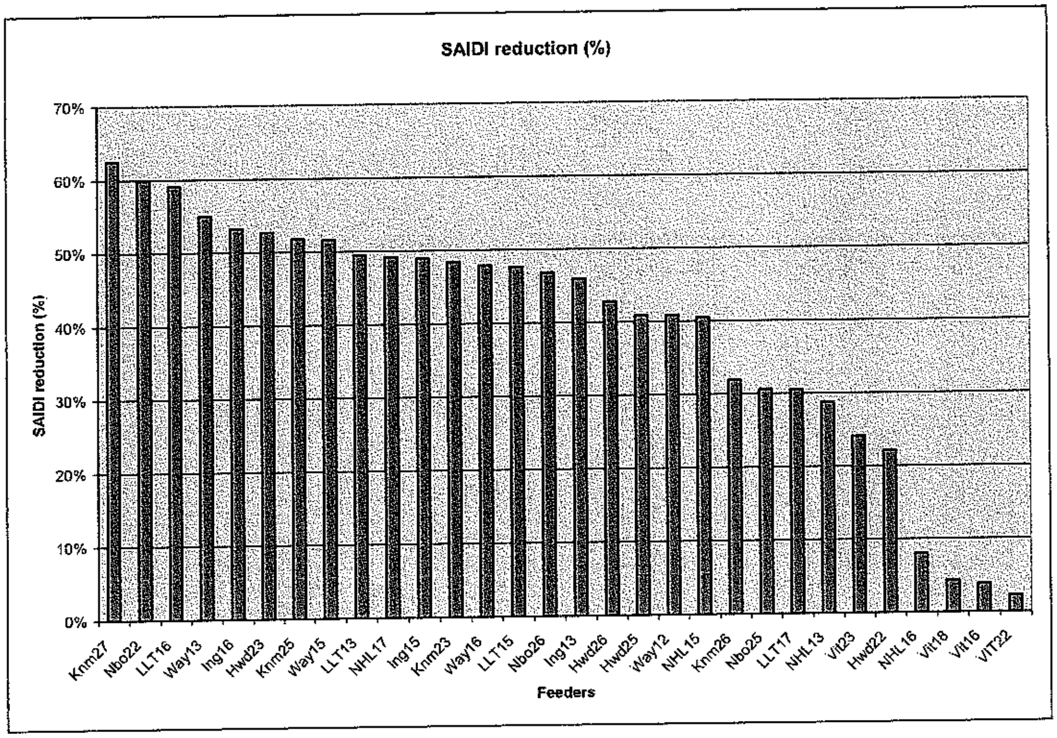

Figure 6-13. SAIDI reduction due to the implementation of the "integrated solution"

Table 6-31 and Table 6-32, show the SAIFI, MAIFI and SAIDI values calculated by SynerGEE before (base case) and after implementing the "integrated solution", respectively. Here it was assumed that for overhead lines the failure rate of temporary faults is two times the failure rate of sustained faults. According to this assumption, 24% of total faults in the pilot study area are temporary and 76% are sustained. These values are fairly close to PSE's assumption that temporary faults are about 20% of total faults. Moreover, it is assumed that for underground lines the failure rate of temporary faults is equal to zero. This is a common assumption for reliability modeling of underground lines when no historical data for temporary faults are available.

Table 6-31. Reliability indices for the base case

Zone - ID	SAIFI - A	SAIFI - B	SAIFI - C	SAIFI - T	MAIFI - A	MAIFI - B	MAIFI - C	MAIFI - T	SAIDI - A	SAIDI - B	SAIDI - C	SAIDI - T	Customers - T
System	0.76	0.82	0.71	0.77	0.76	0.92	0.73	0.82	94.67	98.64	89.96	94.82	36476
Hwd22	1 08	0.98	1 18	1.06	0.24	0.24	0.24	0.24	118.72	106.46	114.35	112.29	1339
Hwd23	0.48	0.48	0.49	0.48	0.67	0.67	0.67	0.67	76.24	70.60	79.82	76.58	524
Hwd25	0.60	0 53	0.51	0.55	0.46	0.46	0.46	0.46	94.90	87.95	93.45	91.01	1224
Hwd26	0.70	0.85	0.73	0.80	1 09	1 09	1 09	1 09	119.95	145.24	132 10	137 32	574
Ing13	1.41	1 25	1 32	1 31	1 60	1.58	1.65	1 60	139.93	131 11	122 56	131 72	1615
Ing15	1 73	1 44	1.65	1 58	1 92	1 91	1.83	1 89	158.61	136.58	168.40	151 41	2708
Ing16	1 07	0.99	0.86	0.98	1 16	1 16	1 16	1.16	177.59	153.69	146.90	159 10	1335
Knm23	1 05	0.95	0.95	0.97	1 33	1 33	1 33	1.33	160.75	140.35	136.99	144.32	1396
Knm25	0.25	0.26	0.26	0.26	0.30	0.30	0.30	0.30	19.89	20.25	20.83	20.32	1900
Knm26	0.65	0.56	0.66	0.61	0.02	0.02	0.02	0.02	103.45	82.32	106.38	94.58	1420
Knm27	1.27	1 26	1.02	1 20	1 56	1 56	1 56	1 56	152.25	147.48	147.54	148.71	1053
LLT13	0.68	0.63	0.63	0.64	0.81	0.81	0.81	0.81	87 12	83.36	81 96	84 05	817
LLT15	0.33	0.32	0.33	0.33	0.31	0.31	0.31	0.31	25.69	25.33	26.09	25.71	1073
LLT16	2 35	2 32	2 30	2 33	3.65	3.85	3.85	3.85	217 38	189.34	209.98	203.51	1011
LLT17	0.89	0.79	0.77	0.82	0.74	0.77	0.83	0.77	133.84	131.89	119.52	129.08	883
Nbo22	0.59	0.56	0.65	0.59	0.72	0.72	0.72	0.72	61.98	59.57	67 18	62 48	1316
Nbo25	0.32	0.35	0.43	0.37	0.00	0.00	0.00	0.00	41.29	39.26	40.86	40.18	872
Nbo26	0.74	0.95	0.72	0.81	1 19	1 19	1 19	1 19	108.48	122.36	106.83	113.00	689
NHL13	0.32	0.30	0.26	0.29	0.05	0.05	0.05	0.05	83.31	91.65	92 64	88.72	1999
NHL15	0.19	0.19	0.20	0.19	0.14	0.14	0.14	0.14	22 72	21 18	24.57	22 95	2664
NHL16	0.29	0.30	0.32	0.31	0 15	0.15	0.15	0.15	40.45	42 66	42 19	41.75	1885
NHL17	1 35	0.61	0.69	0.93	0.95	0.95	0.95	0.95	154.47	78.61	79.40	108.41	548
Vit16	0.05	0.04	0.04	0.05	0.00	0.00	0.00	0 00	7.45	7.27	6.92	7.23	871
Vit18	0.47	0.58	0.47	0.53	0.00	0.00	0.00	0.00	69.45	121.36	69.67	98.24	129
VIT22	0.03	0.03	0.03	0.03	0.00	0.00	0.00	0.00	7.43	7.39	7.37	7.40	133
Vit23	0.73	0.77	0.73	0.74	0.00	0.00	0.00	0.00	101.67	107.99	83.70	97.60	1963
Way12	0.38	0.52	0.35	0.44	0.29	0.29	0.29	0.29	79.00	85.84	75.33	81.34	816
Way13	1 18	1.08	1.23	1 12	1.52	1 52	1 52	1 52	100.00	104.53	120.58	105.53	756
Way15	1 46	1 59	1 72	1 59	2.46	2 54	2.52	2 51	157.22	155.37	175.74	161.36	1362
Way16	0.48	0.49	0.50	0.49	0.69	0.69	0.69	0.69	86.00	90.16	97.88	91.74	1598

In Table 6-31 and Table 6-32, the reliability indices of the pilot study area and the feeders are shown as per phase and total values. The reliability improvements for the pilot study area and most of the feeders are significant. For instance, the total reductions in SAIFI and MAIFI for the pilot study are approximately 52% and 32%, respectively.

Table 6-32. Reliability indices after implementing the "integrated solution"

Zone - ID	SAIFI - A	SAIFI - B	SAIFI - C	SAIFI - T	MAIFI - A	MAIFI - B	MAIFI - C	MAIFI - T	SAIDI - A	SAIDI - B	SAIDI - C	SAIDI - T	Customers - T
System	0.38	0.38	0.35	0.37	0.52	0.62	0.52	0.56	54.21	53.75	50.51	52.91	36476
Hwd22	0.87	0.79	0.90	0.84	0.24	0.24	0.27	0.25	92 71	84 74	85 78	87.44	1339
Hwd23	0.20	0.22	0.28	0.24	0.25	0.27	0.31	0.29	31.82	31.05	40.66	36.20	524
Hwd25	0.33	0.25	0.26	0.27	0.22	0.29	0.25	0.26	57.29	50.14	58.35	53.83	1224
Hwd26	0.45	0.48	0.46	0.47	0.71	0.53	0.71	0.60	66.00	84.96	71 74	78.54	574
Ing13	0.70	0.55	0.60	0.60	0.99	1 19	1 21	1 14	78.89	69.00	66.89	71 25	1615
Ing15	0.88	0.72	0.92	0.82	1 46	1 40	1 27	1 38	86.65	66.50	85.05	77 28	2708
Ing16	0.49	0 42	0.29	0.41	0.89	0.85	1 04	0 91	89.80	69.35	65.08	74.40	1335
Knm23	0.46	0.45	0.49	0.46	0.73	0.73	0.78	0.75	82.23	72.73	70.52	74.38	1396
Knm25	0 10	0.10	0.12	0.11	0.22	0.22	0.22	0.22	9.19	9.33	11 03	9.80	1900
Knm26	0.37	0.28	0.36	0.32	0.23	0.27	0.27	0.26	71 91	53.43	75.32	64.38	1420
Knm27	0.55	0.55	0.38	0.51	0.71	0.78	0.79	0.76	62 86	54 09	52 06	55.80	1053
LLT13	0.32	0.25	0.27	0.28	0.49	0.32	0.42	0.39	50 18	36.80	44.92	42 47	817
LLT15	0.13	0.15	0.13	0.14	0.34	0.30	0.31	0.31	13.19	13.97	13.14	13.46	1073
LLT16	0.95	0.87	0.89	0.90	1 64	1 66	1 64	1 65	94 54	73.14	85.89	83.16	1011
LLT17	0.56	0.45	0.39	0.47	0 73	0.81	0.87	0 79	92 42	95.58	78.98	89 65	883
Nbo22	0.28	0.21	0.32	0.27	0.40	0.38	0.44	0.40	26.20	22 65	26.87	25.06	1316
Nbo25	0 19	0.18	0 16	0.17	0.09	0.10	0.07	0.09	33.24	27 19	25.19	27 88	872
Nbo26	0.33	0.41	0.37	0.38	0.44	0.57	0.45	0.49	52 18	69.00	55.90	60.09	689
NHL13	0.13	0 13	0.13	0.13	0.24	0.20	0.17	0.21	56 85	67 00	67 46	63.17	1999
NHL15	0.08	0.06	0.09	0.08	0.17	0.18	0.18	0.18	13.39	12 20	15 06	13.65	2664
NHL16	0.18	0.20	0.22	0.20	0.28	0.26	0.25	0.26	31.61	34.20	33.23	32 97	1885
NHL17	0 76	0.22	0.28	0.46	0.30	0.47	0.65	0.48	89.62	31.63	33.81	55.11	548
Vit16	0.05	0.04	0.04	0.04	0.00	0.00	0.00	0 00	7.13	7.03	6.67	6.95	871
Vit18	0.23	0.34	0.23	0 29	0.25	0.25	0.25	0.25	50.70	100.70	50.96	78.44	129
VIT22	0.03	0.03	0.03	0 03	0.00	0.00	0.00	0.00	7.26	7.22	7.20	7.23	133
Vit23	0.26	0.24	0.25	0.25	0.27	0.27	0.29	0.28	77 96	81 20	63.61	74 08	1963
Way12	0.26	0.33	0.24	0.29	0.33	0.36	0.31	0.34	46.03	53.09	41 06	48.12	816
Way13	0.53	0.48	0.48	0.49	0.87	0.91	1 00	0.92	43.14	49.95	39.87	47.47	756
Way15	0 56	0.71	0.73	0.67	1.23	1 76	1 71	1 61	69.31	75.90	90 59	78.14	1362
Way16	0.22	0.21	0.28	0.24	0.31	0.30	0.36	0.33	42.32	47.99	51.91	47.80	1598

Cost-Effectiveness

Table 6-33 and Figure 6-14 show the results of the cost-effectiveness analysis of implementing the "integrated solution" for the pilot study area. From the analysis of Table 6-33 it can be concluded that this alternative is cost-effective for about 20% of feeders. The average cost-effectiveness for the pilot study area is 0.32 CMI/$, which does not exceed the threshold of 0.5 CMI/$.

This is due to the fact that most of the alternatives considered in the "integrated solution" are designed for improving the reliability of the overhead lines and the pilot study area is only 36% overhead. This limits the effectiveness of the integrated solution

However, it is expected that the effectiveness of the integrated solution increases when implemented for improving the reliability of PSE's system, given this is approximately 52% overhead. A detailed analysis on this subject in presented in Section 7.

Table 6-33. Cost-effectiveness of the "integrated solution"

#	Feeder	Customers	CMI reduction	Cost ($)	CMI/$
1	Ing15	2 708	200 744	191 261	1 05
2	Ing16	1 335	113 075	145 589	0 78
3	Way15	1 362	113,346	177 607	0 64
4	Ing13	1 615	97 659	160 419	0 61
5	Knm23	1,396	97,636	163 262	0 60
6	LLT16	1,011	121,674	211 729	0 57
7	Knm27	1 053	97 834	208 818	0.47
8	Way16	1 598	70 216	180 697	0.39
9	NHL13	1,999	51 074	150 971	0.34
10	Way13	756	43 893	146 950	0 30
11	Nbo22	1 316	49 245	175 693	0 28
12	Vit23	1 963	46 170	172 582	0 27
13	Hwd22	1 339	33 274	143 084	0 23
14	Knm26	1,420	42 884	188 000	0 23
15	LLT13	817	33 971	149 309	0 23
16	LLT17	883	34,817	158 062	0 22
17	Hwd25	1,224	45,508	208.737	0 22
18	Hwd26	574	33 740	171 443	0 20
19	Way12	816	27 108	139 060	0 19
20	Nbo26	689	36 455	189 790	0 19
21	NHL17	548	29 208	157 735	0 19
22	NHL15	2 664	24 775	169 435	0 15
23	Knm25	1 900	19 988	149 491	0 13
24	NHL16	1,885	16,550	133 375	0 12
25	Hwd23	524	21,159	204 068	0 10
26	LLT15	1,073	13 144	151 750	0.09
27	Nbo25	872	10,726	144 066	0 07
28	Vit18	129	2 554	120,900	0 02
29	VIT22	133	23	4,800	0.00
30	Vit16	871	244	57,777	0.00
	System	**36,473**	**1,528,583**	**4,726,461**	**0.32**

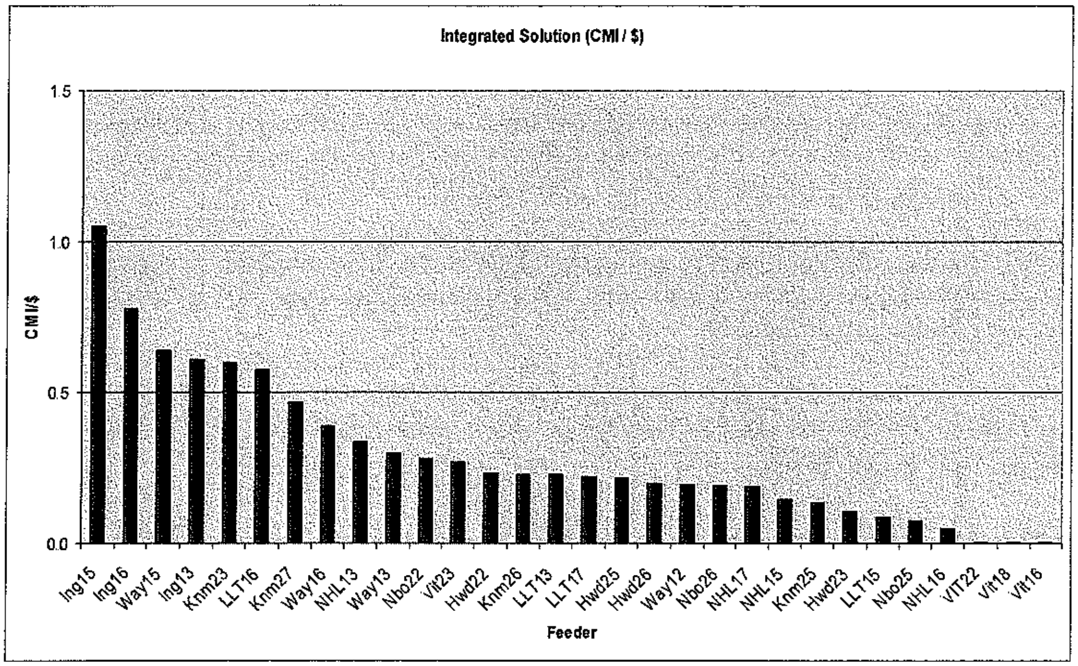

Figure 6-14. Cost-effectiveness of the "integrated solution"

Interaction Effects

The costs and benefits of reliability projects were often times examined in isolation without considering other projects When multiple reliability projects are performed together, the benefits of the integrated solution are typically lower than the sum of the project benefits considered separately We used the integrated solution of the pilot study to account for this effect.

In the non-integrated analysis, the SAIDI reductions due to individual projects are added up without considering any interactions, this is shown in Figure 6-15. For instance, an interaction effect occurs when the "feeder inspections" and "DA reclosers" alternatives are implemented together The "feeder inspections" alternative leads to a reduction of the failure rates of overhead lines, which consequently decreases the effectiveness of the DA reclosers

The cost of the integrated solution of the pilot study was $4.7 million and resulted in a SAIDI reduction of 44.2%. When spending the same $4 7 million based on non-integrated analyses, the SAIDI reduction is approximately 65%, as shown in Figure 6-15 This is a difference of 21%. However, the benefits of the parametric projects were determined by examining their impact on the integrated solution, and therefore already include project interactions. As such, it is assumed that the aggregated SAIDI benefits are reduced by 15% to account for project interactions.

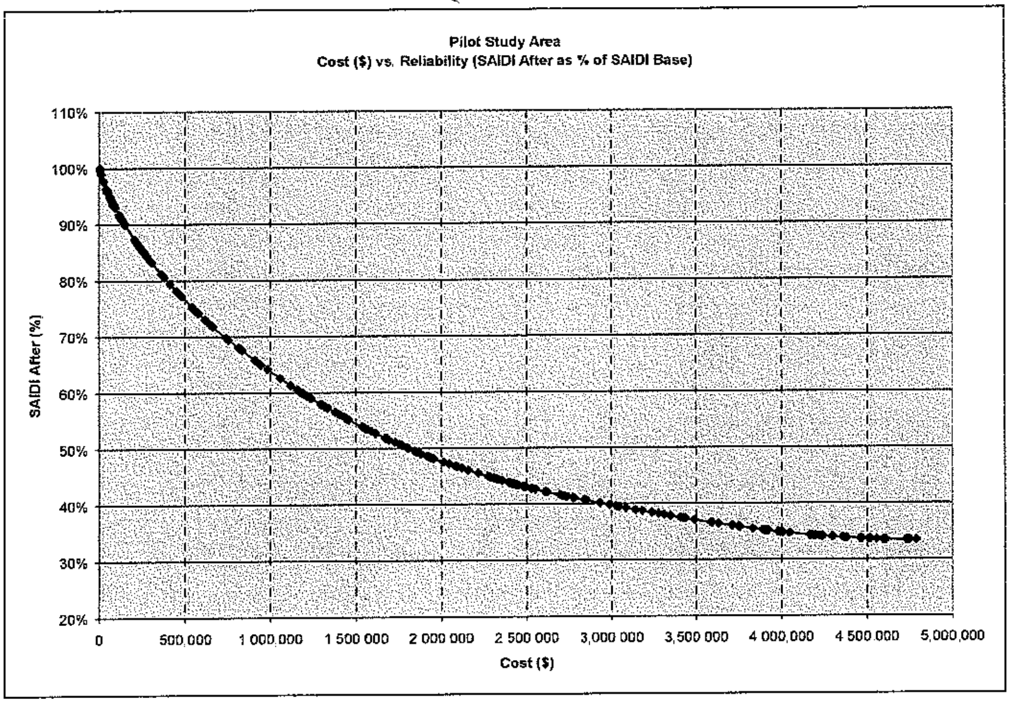

Figure 6-15. SAIDI reduction values (%) obtained by adding up the improvements due to individual alternatives

7 Extrapolation for the Total PSE System

The analysis that was performed for each of the reliability options in section 6 provided costs and benefits for the pilot area which was modeled in detail. This area contained a variety of different feeder configurations upon which to base potential reliability benefits elsewhere on the PSE system by implementing the various reliability options tested on the pilot system. A strategy was developed to take the pilot area results and extrapolate them to achieve expected benefits and costs for the whole PSE system

7.1 Extrapolation Strategy

The goals of the extrapolation strategy are:

- Recommend a reliability roadmap for the whole PSE system that would provide first quartile reliability performance with a 10 year investment program
- Identify a portfolio of reliability options that would achieve these results most cost-effectively
- Identify the level of investment that would be required in each county to achieve these results

The strategy is based on evaluating the features and characteristics of the feeders in the Pilot area and determining what features and parameters can be used to identity corresponding feeders elsewhere in the PSE system. Table 7-1 shows a summary of features that were considered for performing this extrapolation.

Table 7-1. System Features by County

	Pilot Area	Island	Jefferson	King	Kitsap	Kittitas	Pierce	Skagit	Thurston	Whatcom	Total System
Reliability											
SAIDI ('05-'07 Avg)	94.82	149.7	365.4	115.1	255.5	172 8	99.1	149.5	170.2	125.7	143.4
SAIDI 2017 Target	56.892	85.7	99.6	69.3	79.1	116.6	82.8	94.7	84.2	88.8	77.9
SAIDI Target Reduction	40.0%	42 7%	72.7%	39.8%	69.0%	32.5%	16.4%	36.7%	50.5%	29.3%	45.7%
System Information											
Customers	36,476	34,308	17,169	511,947	113,326	11,304	98,443	56 453	116,787	93,636	1 089,849
Sq. Mi. Served	?	169	202	895	368	388	403	488	523	561	3,997
Distribution Subs.	9	10	6	124	25	8	28	20	30	28	288
Feeders	30	34	16	561	101	16	96	65	123	103	1,145
OH Ckt Miles	203.6	329 8	315 0	2987 4	1279 9	490.1	1041 8	1321.7	1474 7	1113.0	10,557
UG Ckt Miles	358.3	342 9	237 1	4258 5	1023.3	288 3	1065 1	529.1	1199 5	690.4	9,992
Total Miles	561 9	672 7	552.1	7245.9	2303.2	778.4	2106.9	1850.8	2674 2	1803.3	20,550
Ratios											
Cust/ sq.mi.	?	203.0	85.0	572 0	308.0	29.1	244.3	115.7	223 3	166 9	263.5
Cust/ Feeder	1215.9	1009.1	1073.1	912.6	1122.0	706.5	1025.4	868.5	949.5	909.1	944.7
Cust/ Ckt-mi	64.9	51.0	31.1	70.7	49.2	14.5	46.7	30.5	43.7	51.9	53.0
Fdr/ Sub	3.3	3.4	2 7	4.5	4.0	2.0	3.4	3.3	4.1	3.7	4 0
% OH	36.2%	49.0%	57 1%	41 2%	55.6%	63.0%	49 4%	71.4%	55 1%	61 7%	51 4%
% UG	63.8%	51.0%	42.9%	58.8%	44.4%	37.0%	50.6%	28.6%	44.9%	38.3%	48.6%
Miles/ Fdr	18.73	19.8	34.5	12.9	22.8	48.7	21.9	28.5	21.7	17.5	17.9

7.2 Extrapolation of Roadmap Projects

Based on pilot area results, rules were determined for extrapolation to the rest of the PSE system. Typically extrapolation is done for each PSE feeder based on specific feeder characteristics. Feeder results for each county are then aggregated to show county-level roadmap estimates. Descriptions for each project are now provided

Project: New 3ϕ line SCADA reclosers

Description: Place new reclosers in new locations on new Class 2 poles, which are assumed to replace an existing pole. These reclosers are set to "fuse clear." They are outfitted with communications so that they can quickly be opened and closed after a fault occurs

Cost: The assumed cost of $38,400 per location is based on the PSE estimation tool plus $10,000 added for communications equipment

Amount: One unit for feeders with OH exposure between 10-25 miles. Two units for feeders with OH exposure between 25-35 miles. Existing reclosers are subtracted from this amount. For example, an existing feeder with 30 miles of OH exposure and an existing recloser is assigned one new unit

Benefit: CMI reduction is assumed to be 10% per device added, which is based on model results and is a bit conservative. In the model, SAIDI reduction for feeders with 1 new recloser was an average of 12.1%, and SAIDI reduction for feeders with 2 new reclosers was an average of 23.9%

Project: New 3ϕ line reclosers

Description: Place new reclosers in new locations on new Class 2 poles, which are assumed to replace an existing pole. These reclosers are set to "fuse clear." They are not outfitted with communications

Cost: The assumed cost of $28,400 per location is based on the PSE estimation tool.

Amount: Three units for feeders with OH exposure over 35 miles. Existing reclosers are subtracted from this amount. For example, an existing feeder with 50 miles of OH exposure and an existing recloser is assigned two new units.

Benefit: CMI reduction is assumed to be 10% per device added, which is based on model results and is a bit conservative.

Project: New manual 3ϕ switches

Description: Place new ganged manual switches on new Class 2 poles that are assumed to replace an existing pole.

Cost: The assumed cost of $11,400 per location is based on the PSE estimation tool.

Amount: Two new switches for feeders with OH exposure greater than 5 miles, plus one additional switch per 5 miles of OH exposure, with a limit of 5 new switches. This amount is based on cost-effective switch locations found in the model.

Benefit: CMI reduction is assumed to be 5% per device added, which is based on pilot area results and is a bit conservative. For the pilot area, a single new switch reduced feeder SAIDI by an average of 7.4% and three new switches reduced feeder SAIDI by an average of 21.2%.

Project: New UG SCADA switches

Description: New pad-mounded SCADA switches in either new locations or in locations with existing manual padmounted switchgear. They are outfitted with communications so that they can quickly be opened and closed after a fault occurs.

Cost: The assumed cost of $77,400 per location is based on the PSE estimation tool (a new VISTA-10 with a new vault for all locations) plus $10,000 added for communications equipment

Amount: 1.5 new switches are added to the 100 circuits with the most UG exposure. This implies a normally-closed switch plus a normally-open tie switch that is shared between two feeders.

Benefit: CMI reduction is assumed to be 15% per feeder affected, which is based on pilot area, which showed a 15% reduction

Project: New OH SCADA switches

Description: Place new OH SCADA in new locations on new Class 2 poles, which are assumed to replace an existing pole. They are outfitted with communications so that they can quickly be opened and closed after a fault occurs. These devices are assumed to be identical to the new SCADA reclosers, but operated with the reclosing functions disabled. This approach will allow for a flexible and robust distribution automation system.

Cost: The assumed cost of $38,400 per location is based on the PSE estimation tool plus $10,000 added for communications equipment.

Amount: 1.5 new units are added to all feeders where new DA Reclosers are installed. This implies a normally-closed switch plus a normally-open tie switch that is shared between two feeders.

Benefit: CMI reduction is assumed to be 15% per feeder affected. In the pilot area, a 1.5 SCADA scheme resulted in an average 18% reduction.

Project: Animal guards
Description: Installation of bushing covers on overhead equipment.
Cost: Cost per feeder is assumed to be $10,000. This is based on a cost of $50 per location and 200 locations per feeder.
Amount: Feeders with more than 40% OH exposure are selected for animal guard installation.
Benefit: Benefits are based on PSE historical animal-related outages with an assumption that 37% of animal-related failures can be eliminated. On the model, which is 36% OH, this resulted in a 3.5% SAIDI reduction. CMI reductions per feeder are normalized based on %OH. For example, a feeder with 72% OH is assumed to have a 7% CMI reduction.

Project: Spacer cable
Description: Replace existing bare OH with compact insulated OH with steel neutral used as messenger. This assumes a complete rebuild.
Cost: The cost per mile of $151,000 is based on the PSE cost estimation tool for tree wire reconductoring.
Amount: 1 mile of spacer cable is placed on the 30 feeders with the highest CMI, for a total of 30 miles.
Benefit: Each affected feeder is assumed to have a CMI reduction of 3.5%; this is based on an assumed reduction of on-ROW tree failures of 75% and an assumed reduction of off-ROW tree failures of 50%. Results for the pilot area were an average 3.5% CMI reduction.

Project: New lateral fuses
Description: New fuses directly off the main trunk on existing poles.
Cost: The cost of $2000 is a weighted average of the cost of 1f, 2f, and 3f installations as seen in the PSE cost estimation tool.
Amount: For feeders with OH exposure greater than 5mi, 5 new fuse locations are assumed. This is based on model results.
Benefit: CMI reduction of 6% per feeder is equal to the pilot area results.

Project: Faulted circuit indicators
Description: Install non-SCADA faulted circuit indicators on main trunks (both OH and UG). For OH, these devices are visible from the ground. For UG, these devices are visible when the pad-mounted switch is opened.
Cost: Cost is assumed to be $400 per location based on the experience of Quanta Technology.
Amount: 12 locations per feeder for all feeders.
Benefit: CMI reduction is assumed to be 4% per feeder. This is based on model results that assume an average response time reduction of 15 minutes per outage event.

Project: OH feeder inspections
Description: Overhead visual and infrared inspection of OH main trunks on a five-year cycle
Cost: The cost of $2200 per mile is based on $1100 per mile with two inspections over the ten-year period The $1100 per mile is based on actual costs for a similar US utility and includes the cost of fixing identified problems.
Amount: The amount assumes that 30% of all OH exposure is main trunk, and that all of the main trunk will be inspected on a 5-year cycle.
Benefit: CMI reduction was 5.3% for the model, which is 36% OH. CMI reductions per feeder are normalized based on %OH. For example, a feeder with 72% OH is assumed to have a 10.6% CMI reduction. The 5.3% reduction in the model is based on a 20% reduction of all failure types that could potentially be prevented through an inspection program.

Project: Recloser inspections
Description: Visual examination of the device, exercising the device, and inspecting the control cabinet. Inspections are assumed to occur on a 3-year cycle.
Cost: The cost is based on $250 per inspection (4 per man-day), multiplied by 3.33 to account for a 3-year cycle over the ten year period
Amount: The number is based on the existing number of reclosers plus the proposed number of new SCADA reclosers plus the new number of non-SCADA reclosers.
Benefit: Benefits assume that inspected devices operate properly 3% more of the time when compared to uninspected devices. This results in a CMI reduction of 0.22% per device on the model, which is used for CMI reductions for the remainder of the system.

Project: Fuse saving during storms
Description: When major wind storms are approaching, change all of the SCADA line recloser settings to "fuse save." Substation relays are assumed to still remain in "fuse clear" mode
Cost: The assumed cost of $1000 per new SCADA reclosers includes both any necessary device settings, plus any necessary costs for software and operator training.
Amount: The number of devices is equal to the number of new SCADA reclosers.
Benefit: The CMI reduction of 1% per device is based on the model, assuming that 25% of all CMI is due to storms where this scheme would be utilized

Project: UG switch inspections
Description: Visual examination of the device and exercising the device. Inspections are assumed to occur on a 3-year cycle.
Cost: The cost of $667 is based on $200 per inspection (4 per man-day), multiplied by 3.33 to account for a 3-year cycle over the ten year period.
Amount: The amount is based on an assumed one UG switch per 7 miles of UG exposure, which is characteristic of the pilot area. All UG switches are assumed to be included in this program.
Benefit: Benefits assume that inspected devices operate properly 3% more of the time when compared to uninspected devices. This results in a CMI reduction of 0.57% per device on the model, which is used for CMI reductions for the remainder of the system.

Project: OH SCADA switch inspections
Description: Visual examination of the device, exercising the device, and inspecting the control cabinet. Inspections are assumed to occur on a 3-year cycle.
Cost: The cost is based on $250 per inspection (4 per man-day), multiplied by 3.33 to account for a 3-year cycle over the ten year period.
Amount: The number is equal to the number of new OH SCADA switches.
Benefit: Since there are currently no OH SCADA switches (essentially), no incremental benefit is assumed for this activity. However, if this activity is not performed, the benefits of the new devices will decline over time.

Project: UG SCADA switch inspections
Description: Visual examination of the device, exercising the device, and inspecting the control cabinet. Inspections are assumed to occur on a 3-year cycle.
Cost: The cost is based on $250 per inspection (4 per man-day), multiplied by 3.33 to account for a 3-year cycle over the ten year period.
Amount: The number is equal to the number of new UG SCADA switches
Benefit: Since there are currently no UG SCADA switches (essentially), no incremental benefit is assumed for this activity. However, if this activity is not performed, the benefits of the new devices will decline over time.

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7.3 Extrapolation of Projects in Other Budgets

Based on pilot area results, rules were determined for extrapolation to the rest of the PSE system. Typically extrapolation is done for each PSE feeder based on specific feeder characteristics. Feeder results for each county are then aggregated to show county-level roadmap estimates. Descriptions for each project are now provided.

Project: Circuit Segmentation
Description: The PSE storm hardening plan called for added overhead sectionalizing switches for increased "circuit segmentation" capability during storms. Since the reliability roadmap already assumes a large number of new sectionalizing switches for this purpose, these components of the hardening plan are no longer necessary.
Cost: The PSE storm hardening plan calls for $12,384,000 for installing solid blade cutouts on primary laterals between fuses. It also calls for $15,480,000 for installing switches on primary feeder. These costs are no longer necessary if the new OH switch program in the reliability roadmap is undertaken.
Amount: n/a
Benefit: n/a

Project: Critical Pole Hardening
Description: Quanta Technology recommends that an additional item be added to the PSE storm hardening plan. This includes replacing the poles at location of major equipment with stronger poles that are unlikely to break during a major storm. Major equipment poles include reclosers, switches, cap banks, automated devices, and CellNet collectors, and freeway crossings.
Cost: $4900 per location is based on PSE cost model for 40' Class 2 pole replacement. This is conservative, because storm guying and/or pole reinforcement can probably be used in certain cases
Amount: Based on pilot area analysis, a typical feeder currently has an average of 6 critical equipment poles Assume addition of at least one recloser per feeder to give average of 7 poles per feeder.
Benefit: n/a

Project: Pole Test and Treat Program
Description: Quanta Technology recommends that PSE pursue a wood pole test-and-treat program on a 10-year cycle. These estimates are for distribution poles only. After testing, acceptable poles are treated. Rejected poles are then assessed to determine whether they are overloaded. If overloaded, poles that can be reinforced are reinforces and are otherwise replaced.
Cost: Cost is $35 per test-and-treat, $25 per pole loading calculation, $550 per reinforcement, and $4800 for replacement Total cost per year is $4,295,379. This cost is multiplied by ten for inclusion in the roadmap cost
Amount: Based on 10,557 miles of OH and an assumed span length of 150 feet, it is assumed that PSE has 369,495 wood distribution poles and that 10% of these will be inspected per year. Assumed initial rejection rate is 4%, and that 3% need action after the loading assessment. It is further assumed that 50% of poles requiring work can be reinforced, and the remainder replaced
Benefit: n/a

Project: Substation Automation
Description: The project assumes that feeder breakers not currently equipped with SCADA become equipped with SCADA so that they can be remotely opened and closed
Cost: This is being done through another budget. No incremental cost is assumed.
Amount: The number of feeders is equal to the number of existing feeder breakers that do not have SCADA
Benefit: The CMI reduction of 2.6% per feeder affected is based on the average effect for feeders in the model. This assumes that switching times are reduced by 15 minutes since crews do not have to drive back to the substation to reset breakers.

Project: Improved Fuse Coordination
Description: The project assumes that fuses will increase their likelihood of being properly coordinated so that the protection device closest to a fault will clear the fault.
Cost: This is being done through another budget. No incremental cost is assumed.
Amount: The number of feeders is equal to the number of existing feeder breakers that do not have SCADA
Benefit: The CMI reduction of 7.3% per feeder affected is based on the average effect for feeders in the model. This was done by assuming miscoordination happens 7% less often after the coordination study.

Project: Mobile Workforce Management
Description: This project assumes that PSE first responder trucks are outfitted with mobile computers and GPS trackers that are integrated with the new outage management system
Cost: This is being done through another budget. No incremental cost is assumed.
Amount: The number of feeders is equal to the number of existing feeder breakers that do not have SCADA.
Benefit: The CMI reduction of 1.4% per feeder affected is based on the average effect for feeders in the model. This was done by assuming a reduction of 5 minutes for outage response time

Project: Hazard Tree Removal
Description: This project assumes that PSE spends an incremental amount of vegetation management money to identify and remove hazard trees both on and off of the PSE right-of-way.
Cost: This is being done through an incremental increase of $10 million to the vegetation management budget.
Amount: The amount is based on the above cost.
Benefit: The CMI reduction for each feeder is based on a 3% reduction multiplied by the percentage of the feeder that is overhead and then divided by the percentage of the overall PSE system that is overhead.

Project: Off-ROW Tree removal
Description: This project assumes that PSE spends an incremental amount of vegetation management money to identify and remove off of the PSE right-of-way that pose a reliability risk.
Cost: This is being done through an incremental increase of $20 million to the vegetation management budget
Amount: The amount is based on the above cost.
Benefit: The CMI reduction for each feeder is based on a 3% reduction multiplied by the percentage of the feeder that is overhead and then divided by the percentage of the overall PSE system that is overhead.

7.4 Cost versus Reliability Analysis

A detailed description of the system benefits and costs of the roadmap are provided in the next section. These results include the amount of each reliability improvement activity that is expected to occur in each county. The reliability improvements for each county are also provided.

For each county, a cost-to-benefit ratio ($/CMI) was computed for each of the reliability roadmap options. For the 9 counties and 13 roadmap reliability options, this generated 117 data points. Each data point represents one reliability option for a specific county. When all of these data points are sorted by $/CMI they represent an order for implementation that would permit the most cost-effective results to be achieved up front. These CMI reduction numbers can then be translated into SAIDI values. Figure 7-1 is a plot showing the cumulative CMI reduction and the cumulative dollar spend as projects are implemented in that order.

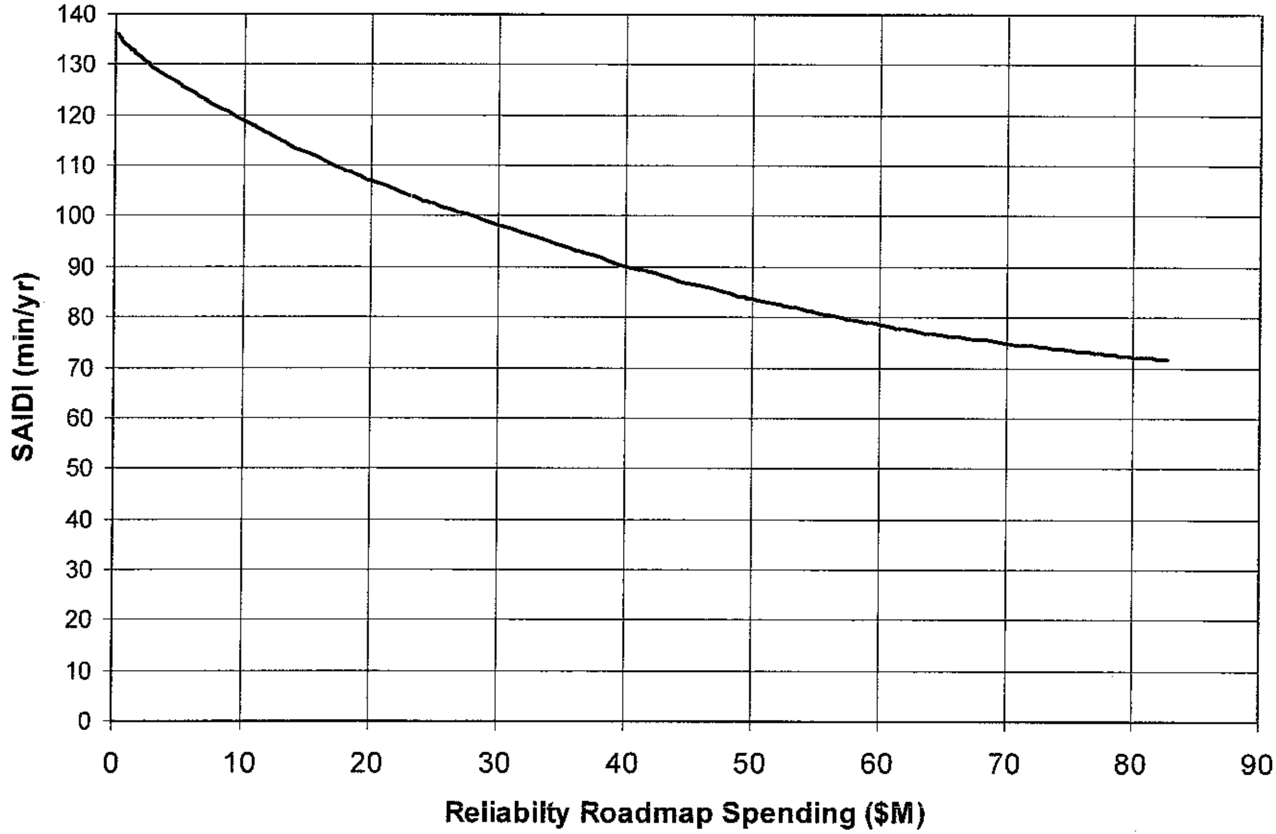

Figure 7-1. PSE System SAIDI versus Reliability Roadmap Spending

8 Ten-Year Roadmap

This section presents the ten year roadmap that resulted from the extrapolation effort documented in the previous section. Benefits are shown as reductions in customer minutes of interruption (CMI), which is proportional to SAIDI reduction. These benefits are based upon the pilot study results, extrapolation rules, and extrapolation results.

The extrapolated CMI benefits of reliability projects were often times computed in isolation without considering other projects. When multiple reliability projects are performed together, the benefits of the integrated solution are typically lower than the sum of the project benefits considered separately. For example, when considered separately, a midpoint recloser might reduce feeder SAIDI by 20% and increased tree trimming on the main trunk might also reduce SAIDI by 20%. However, the benefits of both of these projects both being done is less than 40%. This is because a reduction in tree trimming will result in fewer outages and therefore will result in less benefits for the new recloser. Similarly, the new recloser will more effectively isolate faults and will therefore result in less benefits for increased tree trimming.

We used the integrated solution of the pilot study to account for the effects of project interactions. The cost of the integrated solution of the pilot study was $4.1 million and resulted in a CMI reduction of 44%. When spending the same $4.1 million based on non-integrated analyses, CMI reduction is 65% This is a difference of 21% However, the benefits of the projects that reduce failure rates and repair times were determined by examining their impact on the integrated solution, and therefore already include project interactions. As such, aggregated CMI benefits from roadmap projects are reduced by 15% to account for project interactions

The remainder of this section presents a cost and benefit summary of the roadmap. It then provides an analysis of these costs and benefits in terms of reliability targets and project timing.

8.1 Roadmap Cost and Benefit Summary

Roadmap costs are summarized in Table 8-1. This includes the total estimated costs for each roadmap project. It also includes incremental cost adjustments for projects in other budgets (in this case, all are related to storm hardening). The cost of the reliability roadmap is $83,077,000 over ten years. This roadmap also calls for an increase in the PSE storm hardening budget of $45,431,000 (driven mostly by a wood pole test-and-treat program). This results in a net incremental spending increase of $128,508,000, or about $12.9 million per year over ten years. These numbers are not allocated to any specific year and are not adjusted to include inflation.

Roadmap benefits are summarized in Table 3. This includes estimated CMI reduction by project and by county. It also provides an overall $/CMI score for each project. Total estimated system SAIDI reduction is 45.7%, which is equal to the desired reduction target.

SAIDI reduction by county varies somewhat when compared to targets. King County improvements match targets closely, which is expected since the pilot area (from which assumptions are based) is from King County. The only counties that did not reach their targets are Jefferson and Kitsap. However, these two counties started out with very high SAIDI values and the actual SAIDI minutes reduced in these counties is two to three times higher than the system average. When the actual roadmap is implemented, spending can be prioritized and shifted between counties to achieve desired balance.

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Table 8-1. Reliability Improvement Projects in Roadmap

	Units	$1000/ Unit	Island	Jefferson	King	Kitsap	Kittitas	Pierce	Skagit	Thurston	Whatcom	Total System	Total Cost ($1000s)
Roadmap Projects													
New 3ϕ line DA reclosers	#	38.40	4	4	62	28	3	27	18	28	32	206	7,910
New 3ϕ line reclosers	#	28.40	2	3	18	3	17	4	34	20	14	115	3,266
New manual 3ϕ switches	#	11.40	65	54	586	248	56	198	168	221	191	1,787	20,372
New UG SCADA switches	#	77.40	3	8	60	14	9	20	12	23	3	150	11,610
New OH SCADA switches	#	38.40	6	5	84	41	3	36	21	30	36	262	10,061
Animal guards	Fdrs	10.00	23	12	211	73	14	53	42	65	70	563	5,630
Spacer cable	Miles	151.00	2	1	10	4	1	1	2	8	1	30	4,530
New lateral fuses	#	2.00	100	65	1,035	380	65	315	205	310	265	2,740	5,480
Faulted circuit indicators	#	0.40	408	192	6,732	1,212	192	1,152	780	1,476	1,236	13,380	5,352
OH Feeder inspections	Miles	2.20	99	95	896	384	147	313	397	442	334	3,106	6,833
Recloser inspections	#	0.85	21	22	192	87	29	75	68	93	75	662	563
Fuse saving during storms	#	1.00	4	4	62	28	3	27	18	28	32	206	206
UG switch inspections	#	0.67	49	34	602	146	41	151	72	171	99	1,363	913
OH SCADA switch inspections	#	0.85	6	5	84	41	3	36	21	30	36	262	223
UG SCADA switch inspections	#	0.85	3	8	60	14	9	20	12	23	3	150	128
County Total Spending			$2,589	$2,369	$28,547	$10,276	$2,935	$8,998	$7,775	$11,364	$8,223		$83,077
Projects in Other Budgets													
Circuit Segmentation													-27,864
Critical Pole Hardening													30,341
Pole test-and-treat program													42,954
Danger Tree Removal													10,000
Off ROW Tree Removal													20,000
Cost of Roadmap Projects													83,077
Adjustments for other budgets													75,431
Net Cost ($1000s)													**$158,508**

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Table 8-2. Reliability Benefits of Roadmap (CMI reduction)

	Island	Jefferson	King	Kitsap	Kittitas	Pierce	Skagit	Thurston	Whatcom	Total CMI Reduction	$/CMI
Roadmap Projects											
New 3ϕ line SCADA reclosers	79,613	97,611	1,333,569	563,751	99,345	319,261	138,534	396,076	494,248	**3,522,007**	2.25
New 3ϕ line reclosers	42,137	29,929	586,367	254,160	133,548	173,414	958,831	1,218,420	430,763	**3,827,569**	0.85
New manual 3ϕ switches	984,595	790,577	5,856,322	3,561,236	441,422	1,613,129	1,618,302	3,813,230	1,671,511	**20,350,325**	1.00
New UG SCADA switches	95,309	357,578	1,732,889	532,133	183,896	459,121	284,532	1,483,295	144,892	**5,273,644**	2.20
New OH SCADA switches	119,419	132,890	1,702,283	838,574	77,812	403,208	138,065	594,114	505,245	**4,511,610**	2.23
Animal guards	229,802	182,892	1,536,810	1,004,044	123,034	394,804	483,280	990,226	544,493	**5,489,384**	1.03
Spacer cable	65,465	31,471	360,923	180,873	30,933	36,278	78,954	432,583	31,676	**1,249,157**	3.63
New lateral fuses	339,065	196,300	2,180,271	1,064,329	143,301	558,364	444,093	1,098,228	483,929	**6,507,881**	0.84
Faulted circuit indicators	205,398	250,914	2,356,854	1,158,190	78,148	390,178	337,514	794,895	470,914	**6,043,005**	0.89
OH Feeder inspections	368,590	524,019	3,556,640	2,355,833	180,098	706,182	882,209	1,604,455	1,063,791	**11,241,817**	0.61
Recloser inspections	11,260	7,635	60,131	34,637	5,238	18,864	16,919	42,003	17,697	**214,384**	2.62
Fuse Saving During Storms	7,961	9,761	133,357	56,375	9,934	31,926	13,853	39,608	49,425	**352,201**	0.58
UG switch inspections	85,488	73,560	662,580	338,994	44,231	152,856	98,346	471,983	104,471	**2,032,509**	0.45
Projects in Other Budgets											
Substation Automation	6,191	0	80,770	15,112	14,774	14,737	15,947	0	148,312	**295,844**	---
Improved Fuse Coordination	374,852	457,918	4,301,259	2,113,697	142,620	712,074	615,963	1,450,683	859,419	**11,028,484**	---
Mobile Workforce Mgmt.	71,889	87,820	824,899	405,367	27,352	136,562	118,130	278,213	164,820	**2,115,052**	---
Danger Tree Removal	161,453	104,517	1,189,427	633,767	69,478	270,025	284,739	619,838	345,921	**3,679,166**	---
Off ROW Tree Removal	161,453	104,517	1,189,427	633,767	69,478	270,025	284,739	619,838	345,921	**3,679,166**	---
Total CMI Reduction - Roadmap	2,634,105	2,685,137	22,058,996	11,943,127	1,550,940	5,257,584	5,493,432	12,979,114	6,013,056	**70,615,492**	
Total CMI Reduction - Other Budgets	775,839	754,771	7,585,782	3,801,709	323,701	1,403,425	1,319,519	2,968,573	1,864,393	**20,797,712**	
Gross CMI Reduction	3,409,944	3,439,908	29,644,778	15,744,837	1,874,642	6,661,009	6,812,951	15,947,687	7,877,448	**91,413,203**	
CMI Reduction with 15% discount	2,898,452	2,923,922	25,198,061	13,383,111	1,593,445	5,661,857	5,791,008	13,555,534	6,695,831	**77,701,223**	
SAIDI Before (min)	149.7	365.4	115.1	255.5	172.8	99.1	149.5	170.2	125.7	**143.4**	
SAIDI After (min)	65.2	195.1	65.9	137.4	31.9	41.6	46.9	54.1	54.2	**72.1**	
SAIDI Reduction (min)	84.5	170.3	49.2	118.1	141.0	57.5	102.6	116.1	71.5	**71.3**	
% SAIDI Reduction	56.4%	46.6%	42.8%	46.2%	81.6%	58.0%	68.6%	68.2%	56.9%	**49.7%**	
% SAIDI Target Reduction	42.7%	72.7%	39.8%	69.0%	32.5%	16.4%	36.7%	50.5%	29.3%	**45.7%**	

9 Aging Infrastructure

Today, many investor-owned utilities have begun to increase spending on aging infrastructure, have announced intentions to increase spending on aging infrastructure, or are beginning to experience signs of increased infrastructure failure and are wrestling with how to address the problem.

Some of the first signs of systematic aging infrastructure problems appeared in the summer of 1999, when major electricity outages were experienced in New York City, Long Island, New Jersey, the Delmarva Peninsula and Chicago. These events were investigated by the U.S. Department of Energy through a Power Outage Study Team (POST). The resulting POST report concludes the following (Page S-2):

> *The POST investigations found that the aging infrastructure and increased demand for power have strained many transmission and distribution systems to the point of interrupting service.*

These outages resulted in immediate and large increases in capital spending for the utilities involved.

This section provides an overview of PSE's aging infrastructure. It excludes wood poles since that is discussed in other sections. The assets described have been identified as of interest to PSE.

9.1 Underground Cable

PSE has approximately 9400 miles of underground distribution cable. This accounts for approximately 48% of PSE's distribution system. Of this, PSE has approximately 2300 miles of direct buried high molecular weight (HMW) polyethylene unjacketed underground cable which was installed between 1965 and 1980. This cable contributes to the majority of the underground cable failures. Since 1980, PSE has evolved to fully jacketed TR-XLPE cable installed in a conduit system.

In 1993, PSE established a goal of stabilizing underground outages and established a cable remediation program (CRP) which included replacement and cable injection. The miles of CRP have varied over the years depending upon budget and other resource considerations, but the outage target has been met. In the early 2000's the miles of CRP continually declined and the number of outages began to climb. In 2004, the miles of CRP again increased with the corresponding decrease in outages. It is interesting to note that the miles of CRP in 2007 were the lowest since 1991(approximately 60 miles).

PSE has a good cable program. They track failure rates, locations and causes, have a proactive neutral corrosion program and are getting involved with the various cable diagnostic programs. Cable systems are rated annually based on failures per 100 miles, level of neutral corrosion, and a priority score based on cable type, installation date, number of customers, type of system, and various other factors. In addition, PSE replaces individual cable sections after the third failure.

Many utilities have a formal cable replacement and/or rejuvenation program, similar to PSE that proactively replaces/rejuvenates old cable that is expected to fail in the near future. As with PSE, these programs are generally based upon insulation type.

Continuation of the existing program will maintain a relatively stable outage contribution due to underground cable failures. However at this rate it will take 29 years to replace or refurbish the remaining HMW cable.

From a reliability only perspective, a general increase in the existing CRP is not cost effective when compared to other reliability improvement options provided in this report. However, there may be specific instances, especially with increased emphasis on cable diagnostics that may justify increased expenditures.

9.2 Distribution Substation Transformers

PSE has 250 distribution substation transformers that are of concern because of age, maintenance history and LTC performance. The average age of PSE substation transformers appears to be consistent with the industry. However, there are at least 26 transformers 40 years of age or older.

PSE has a good substation transformer condition assessment program, which includes regular DGA, field electrical testing, Doble testing and paper insulation tests. PSE has very few transformer failures. When one occurs, repairs are normally made in the field. There is an annual replacement program that plans to replace 3 transformers per year. Replacement is based upon maintenance history, condition assessment and LTC performance.

While the reliability associated with the substation transformers is good, the older transformers require high maintenance. With PSE's utilization factor of 86%, it appears appropriate that PSE increase its efforts in proactively replacing its older higher maintenance transformer fleet. PSE costs for a planned substation transformer replacement is $1M. Costs for replacement under emergency conditions have been identified to be 30% greater.

Since PSE has experienced LTC problems, another approach could be to replace the LTC, even on older transformers. These newer LTCs can be reused should the transformer be replaced at a later date. One concern about this approach is the use of the maintenance budget for the LTC replacement versus the use of capital for the transformer replacement.

9.3 Oil Circuit Breakers (Transmission and Distribution)

PSE has 275 transmission and 160 distribution oil circuit breakers of concern because of the age, criticality, maintenance history and environmental impact of failure. PSE currently replaces approximately 10 transmission and 20 distribution breakers per year. Currently the maintenance practice includes breaker profiling, which has been successful in identifying problems and reducing breaker failures

The age of the general population of breakers is consistent with the industry. However there are approximately 370 breakers greater than 50 years old. It is assumed that many, if not all, of the oil circuit breakers identified with concerns are of this vintage.

The distribution oil circuit breaker program appears reasonable, which if continued would replace all of these problem breakers in 8 years. The transformer breaker replacement on the other hand could be accelerated. Under the current plan, it will take 28 years to replace all of the transmission breakers identified.

9.4 Circuit Switchers

PSE has 227 older Type G, Mark II circuit switchers which have a history of mis-operation and require high maintenance resources. PSE replaces approximately 10 of these circuit switchers per year. These replacements are based upon operational difficulties and are coordinated with other substation work.

The industry has experienced problems with the Mark II circuit switcher and they do require additional maintenance attention. It would be appropriate to accelerate the replacement of these devices and not necessarily tie replacement to other work in the station.

9.5 Electromechanical Relays

PSE has approximately 250 electromechanical relay systems or packages and replace an average of 4 packages per year. The replacement criteria are age and criticality of the system.

There are some electromechanical relays that have exhibited problems, but these are limited to a family of relays and are not reflective of electromechanical relays in general. The industry has moved away from electromechanical relays to microprocessor devices because of the cost and additional benefits derived, such as reduced maintenance, flexibility of operation and availability of greater operational information. However there is not a major replacement program of electromechanical relays because of age. Usually the replacement is done in conjunction with other equipment replacement or a change in the protection scheme.

An electromechanical relay replacement program by itself is not recommended. However it is appropriate to change these relays in coordination with other equipment replacement in a station.

9.6 High Side Fuses with Circuit Switchers

PSE has identified that in some cases there may be some high side fuses that are over stressed. These fuse replacements are coordinated with other substation work.

The approach taken by PSE is reasonable. The fuses are identified, prioritized and coordinated with other work.

9.7 Silicon Carbide Arrestors

PSE has an unknown number of silicon carbide arrestors and replaces them whenever a transformer is taken out of service.

Unless there has been a high failure rate of existing silicon carbide arrestors, this approach is reasonable.

9.8 Substation Batteries

PSE currently performs load/impedance tests on its substation batteries and replaces those that fail. An average of 5 batteries is replaced annually.

There are 2 schools of thought regarding substation batteries. Because of the importance of the battery to station operation, one approach is to replace them on a regular cycle, usually 15 to 20 years. The other is to replace them based upon battery test results. If the utility is diligent in its testing program and has a good robust testing procedure, replacements based upon testing results is an acceptable approach.

PSE Aging Infrastructure Review				
Asset	**Number of Units**	**PSE Replacement Approach**	**Annual Replacement Rate**	**Replacement Cycle (Yrs)***
HMW Under-ground Cable	2300 miles	Prioritized after multiple failures or identification of neutral corrosion	80 miles	29
Substation Trans-formers	250	Prioritized based on age and maintenance issues or costs	3	84
Distribution Oil Circuit Breakers	160	Prioritized based on age, criticality, maintenance issues or costs and environmental issues	20	8
Transmission Oil Circuit Breakers	275	Prioritized based on age, criticality, maintenance issues or costs and environmental issues	10	28
Circuit Switchers	277	Prioritized based on operational difficulties and coordinated with other substation work	10	28
Electromechanical Relays	250	Prioritized based on age and criti-cality to system	4	63
High Side Fuses	unk	Prioritized based on fault duty and coordinated with other substation work	3	unk
Silicon Carbide Arrestors	unk	Replace with metal oxide arrestors whenever a transformer is taken out of service	unk	unk
Substation Batter-ies	unk	Replace when battery fails load/impedance test	unk	unk

* Based upon current replacement rate

9.9 Summary

Similar to other utilities, PSE is reviewing its aging infrastructure. As with other utilities, PSE has some facilities that have exceeded their design life and are beginning to create operating problems and/or require higher maintenance resources. Except potentially for the underground HMW cable, these assets have not yet had a major impact on reliability. However because of the vintage of these assets, spare parts are often not available and need to be manufactured, thus increasing restoration and repair times

While PSE is doing some replacement, it appears appropriate that PSE establish a more aggressive proactive replacement program for these assets, especially distribution substation transformers, transmission oil circuit breakers and Mark II circuit switchers.

10 Storm Hardening

In addition to improvement of overall system reliability, PSE has requested a review of their current initiatives to harden the transmission and distribution systems for better performance in storm conditions. In 2007 KEMA was engaged to review PSE's storm preparedness and execution of storm response in the windstorms of December 2006 While the KEMA analysis was focused on storm readiness and performance, the investigation also considered causes of damage and methods to mitigate the magnitude of damage in future storms. That report did not include a hardening analysis but did recommend that PSE conduct a hardening analysis and implement hardening strategies.

Electric infrastructure hardening is a subject that has received much attention in recent years An increasing number of severe weather events throughout the USA and the world have resulted in analysis and consideration of methods to reduce storm damage to electrical facilities Hardening of infrastructures is not a new concept and experienced utility engineers can recommend methods to harden electrical infrastructure with little or no analysis. The issue facing most utilities today, however, is how to achieve some level of infrastructure hardening at a reasonable cost while optimizing the expenditure for maximum benefit Hardening in this sense is much different from "gold plating" - the often used term for overbuilding facilities to ensure reliability.

With few exceptions, techniques and materials to harden infrastructure are not new to the industry. Common methods for hardening include use of larger poles, more guying, conversion to underground, shorter span length, different conductors, etc. The key to an effective hardening effort is the manner in which these techniques are applied to achieve a well-defined objective Many hardening efforts become more expensive and less effective than desired because they do not begin with well-defined objectives, measurable outcomes, and methodologies to ensure optimization of the effort.

10.1 Evaluation of PSE Hardening Strategies

PSE has considered actions to strengthen the transmission and distribution systems against storm damage. These actions were summarized in the PSE document "System Hardening Strategies" and provided to Quanta Technology for review and comment. In the review, Quanta Technology noted that many of the hardening initiatives are addressed in the reliability roadmap. Those points are noted in the following summary of the hardening strategies proposed by PSE and Quanta Technology's comments on those initiatives

SYSTEM HARDENING STRATEGIES*

** System Hardening strategy list result from a brainstorming session with members from Electric First Response, Standards, Engineering and Total Engineering System Planning with the objective of identifying strategies that should be implemented to harden the T&D system to withstand storm outages*

Strategies	Issues	Solution	Benefits	Cost Assumption	Capital Cost	O&M Cost
Improve Fuse Coordination	Distribution System fuse coordination is being compromised by NCC projects that don t upgrade fuses at the time of new installations. Service Provider to look upstream of the new construction project and re coordinate all fuses back to the feeder	Have someone review maps in areas where known miscoordination exists and have maps changed to reflect the correct fuse size we want at each location The result would be that when servicemen replace a blown fuse they can look at the map to get the correct size; mapping and TESP are working on a plan to implement this solution.	Help limit the outage to minimal customers. Reduce serviceman patrol time to allow them to move on to other things.	Hire student intern at cost of $20/hour for 3 months to review maps	$ -	$ 9,600
Quanta Technology Comments	Valid issue and solution. Protective coordination is not generally considered a "hardening" strategy and for purpose of the Quanta Technology analysis, is considered as part of overall protection philosophy and reliability roadmap. Reduction of troubleman patrol time can reasonably be expected based on proper coordination of devices and identification of area of outage through customer outage reporting. Ideally, an outage management system would automate the outage location process and quickly identify the protective device(s) behind which the outage cause can be located.	Any areas where miscoordination is known to exist should be addressed as part of ongoing daily operations. Noting proper fuse sizes on maps or other operational records is required This coordination analysis should be part of the reliability roadmap implementation.				
Engineering Design Practice	When feasible install newly constructed overhead lines on the side of a street that is opposite the prevailing storm winds. In most of PSE's territory the storm winds come from the south or west. In some parts of Whatcom County they come from the north. In canyon areas like North Bend and Enumclaw they come from the east.	Incorporate in next version of Engineering Design Manual	Less OH line outages due to wind.	No cost	$ -	$ -
Quanta Technology Comments	The basic concept of planning new construction for locations with lower storm exposure is reasonable and should be part of design criteria for all new facilities. More fundamental, however is the question of the design wind loading of the overhead facilities. If the basic objective is to have an overhead line that is more resistant to failure to due wind only, the design criteria for wind loading will have more impact than the side of the street on which the facilities are placed.	Quanta Technology suggests that the engineering design review include analysis of wind loading criteria currently incorporated in the design manual, the standard to which PSE believes facilities should be constructed, and efforts to assure that the design specification achieve the objective.	Short term benefit for resulting from this practice is minimal, however there is no incremental cost with the proposed practice If changes in design standards are made, for example increasing pole class for wind load incremental costs will be incurred.			
Circuit Segmentation	Double deadend distribution lines on either side of heavily treed areas that are known to result in outages Install switches to help isolate the outage to the smallest number of customers.	Install switches on primary feeder to help isolate the outage to the smallest number of customers; this solution will be turned over to TESP to apply as part of planning process	Help limit the outage to minimal customers.	Average cost of $7.5K per switch location for 2 locations in 1 032 feeder circuit compywide	$ 15,480,000	1,548,000
Quanta Technology Comments	Concept outlined in this issue and solution is valid; however, the implementation of this concept must be carefully coordinated with other intiatives for cost efficiency and system effectiveness. Assuming the overall reliability roadmap implementation will include installation of reclosers and both manual and automated switches, the location criteria for those devices should include consideration of right-of-way conditions and areas that routinely experience damage during storms. Choice of locations for this hardening is critical and should be chosen after study of historical storm performance of a region and consideration of all available options to lessen storm damage.	Circuit segmentation strategies serve both reliaiblity and storm hardening objectives Switch installations as a hardening strategy should be part of a portfolio of hardening options that is closely coordinated with equipment installations being considered for daily reliability The consideration of switches of various types for hardening or for daily reliability should be taken concurrently.		Cost estimate shown is based on isolating one section of line per feeder Number of feeders appears to be adjusted for UG feeders and customer owned facilities. This estimate should be coordinated with estimated cost of installation of devices for reliability as there is likely duplication of costs.		

Strategies	Issues	Solution	Benefits	Cost Assumption	Capital Cost	O&M Cost
Construction Practices	Cascading transmission structural failures	Double deadend transmission lines on either side of heavily treed areas to prevent cascading structure failure requiring the changing out the poles; this solution will be turned over to Engineering to implement.	Help limit the outage to minimal customers.	Average cost of $15K per location; assume 100 locations companywide	$ 1,500,000	150,000.0
Quanta Technology Comments	This application (transmission lines) has good potential for storm damage mitigation due to the amount of transmission line that is routed cross country or through heavily wooded areas. Coordination of this initiative with vegetation management planning is important as the two should be planned in parallel. Also recognize that cascading failures are not confined to heavily treed areas but also occur in long segments of tangent construction where guying and/or deadends are minimal.	Planning for this initiative should be based on historical damage information and accessibility to ROW information. Cross country lines with limited access should be the target areas for hardening transmission lines and using deadends and storm guying to prevent both individual structure and cascading structure failures.		Number of locations for estimating should be validated through historical records of cascading failures, the severity of those failures, and overall cost/benefit impact to address specific failure locations.		
Construction Practices	In areas that are heavily treed reduce the frequency of damaged transmission conductors falling into a busy road.	Change transmission vertical turns to double deadends without changing the poles; this solution will be turned over to TESP to apply as part of planning process	Help limit the outage to minimal customers.	Average cost of $15K per location; assume 50 locations companywide	$ -	$ 750,000
Quanta Technology Comments	Hardening of major circuits, either transmission or distribution, over major road crossings is a reasonable objective for a number of reasons. As NESC requires Grade B construction over limited access road crossings (Rule 242), a higher strength construction should already be in place for those type roads. Consideration for similar construction standards on major highways and thoroughfares that are not "limited access" should also be considered. Further, NESC requirements for extreme wind ratings apply when 'a structure or its supported facilities exceeds 18m (60 ft.) above ground or water level" which includes many transmission structures or conductors crossing roads.			Locations where this action may be required should be specifically identified for purpose of estimates. NESC requirements may dictate the priority locations.		
Circuit Segmentation	Sectionalizing of damage distribution lines	Install more solid blade cutouts on primary laterals between fuses to allow sectionalizing of damaged distribution lines to reduce the number of customers that remain out from damage; this solution will be turned over to TESP to apply as part of planning process.	Help reduce outage time for customers.	Average cost of $3K per location; assume 4 locations per circuit for 1 032 circuit companywide.	$ 12,384,000	$ -
Quanta Technology Comments	The ability to sectionalize circuits to minimize outage time for the maximum number of customers is a standard operating concept for most utilities. It is primarily considered as a reliability or outage duration management technique. As noted with the earlier segmentation initiative, this action should be considered in conjunction with the overall reliability roadmap so that placement of fuses, reclosers, sectionalizing devices is coordinated for maximum operational benefit.			Cost should be reviewed as part of overall reliability roadmap strategy.		
Switching Scheme	Evaluate transmission automatic switching schemes for impact of momentary outages on substations. Add more circuit breakers to eliminate some of these outages.	Being done as part of transmission planning process; this solution will be turned over to TESP to apply as part of planning process.	Help reduce outage time for customers.	No cost	$ -	$ -
Quanta Technology Comments	This is a reliability strategy that is addressed as part of the overall reliability roadmap.					
Planning Practice	For the transmission system make it a policy to design the protection scheme so that, when transmission lines are looped, no substations are out for a single transmission line fault.	Being done as part of transmission planning process.	Help reduce outage time for customers.	No cost	$ -	$ -
Quanta Technology Comments	This is a reliability strategy that is addressed as part of the overall reliability roadmap.					

Strategies	Issues	Solution	Benefits	Cost Assumption	Capital Cost	O&M Cost
Engineering Design Practice	Discourage the use of distribution compact spacing in heavily treed areas. The close spacing of the conductors catches more limbs and results in more outages when trees are present.	Incorporate in next version of Engineering Design Manual	Help reduce outages.	No cost	$ -	$ -
Quanta Technology Comments	The premise here appears to be that compact spacing catches limbs resulting in permanent faults where wider spacing would allow limbs to fall to the ground The trade-offs between wider phase conductor spacing and overall lateral clearance between conductors and edge of right-of-way must be considered in each case This is an element of line design that is generally the judgment of the designer, so the Engineering Design Manual should include the options to be considered and the pros/cons of each As this initiative is written to "discourage" a particular practice as opposed to eliminating the practice, it leaves the final decision to the judgment of the designer.	Greater reduction in reducing tree limbs in lines would likely come from vegetation management practice of "ground to sky" clearance flared away from the line above the height of the conductors.				
Construction Practices	Strengthen the' weak link' on our T&D system	Look into the "weak link" concept for both transmission and distribution lines; a consultant will need to be hired to review this concept.	Help reduce outages.	To be reviewed by a consultant	$ -	$ 100,000
Quanta Technology Comments	Quanta Technology is aware of this concept being used in limited applications with a few utilities Detailed investigation of the concept design details and specific conditions to be addressed in the field is required.					
Instrastructure Location	Location of transmission poles	Labelling of cross-country transmission line poles where they cross roads. (See Std 0201.0300 on the Standards Dept webpage It has been updated to include marking requirements) Make line designations more visible for helicopter patrol; TESP will pursue this solution.	Help reduce outage time for customers.	In a study by Wayne Harris, it was determined that it will cost about $30 to label a pole Assume that 25% of the 32,000 transmission poles in the company will need to be labelled.	$ -	$ 240,000
Quanta Technology Comments	Agree with this initiative.					
Automate Temporary Fault Clearance on single phase lateral	Temporary faults on single phase laterals cause fuse cutouts to operate requiring serviceman to replace fuse. This lead to a 1 to 3 hours outage for the customers.	Replace single phase cutouts with S&C fuse tripsaver which operates like a single phase recloser; this solution is being tested by TESP and Standards.	Temporary faults will not interrupt service to customers.	Cost for the device is about $1,500 per device We will be trying out the device on 12 laterals in 2008	$ 19,000.00	$ -
Quanta Technology Comments	This is a reliability strategy that is addressed as part of the overall reliability roadmap.			Cost to be included as part of reliability roadmap.		
Improve Maps	Transmission maps	Make better geographic transmission maps.	Help reduce outage time for customers Reduce serviceman patrol time to allow them to move on to other things.	Mark Mass to provide new map books to EFR. Maps are arriving at this time.	0	0
Quanta Technology Comments	Agree with this initiative.					
		TOTAL COST			$ 29,383,000	$ 2,797,600

In addition to the initiatives outlined in the System Hardening Strategies, a number of recommendations related to infrastructure conditions were made in the KEMA report PSE has cataloged those recommendations and assigned priorities for addressing each. The recommendations either being pursued or under consideration are:

- Enhance PSE's transmission vegetation management policy and standards for ROW width.
- Map the most frequently and severely storm impacted areas of the transmission system
- Formalize a plan to broaden ROW in particularly hard hit areas
- Expand PSE Tree Watch program to these areas
- Ensure that all cross country ROW have adequate paths to permit moving equipment inside the ROW.
- Aggressively develop and maintain cross country transmission access roads.
- Develop a comprehensive access road program for cross country transmission lines that:
    - Creates a rating system for road conditions,
    - Identifies roads requiring culvert construction,
    - Provides for upgrade of access roads to hardest and most frequently damaged areas, and
    - Provides funding for the above
- Evaluate hardening opportunities for both transmission and distribution systems by:
    - Conducting a system hardening study,
    - Evaluating additional opportunities for undergrounding,
    - Evaluating use of different transmission structures in hard hit areas, and
    - Matching materials and design standards to the region's weather conditions.

10.2 Leading Practices

The programs and initiatives outlined by PSE in the System Hardening Strategies are all valid approaches to hardening of both transmission and distribution system components. Each initiative as a stand alone action will achieve some degree of additional strengthening of the infrastructure. However, industry leading practice indicates a more comprehensive approach to a hardening effort. A comprehensive approach would coordinate all the strategies that are being brought forward in the reliability roadmap with infrastructure hardening activities to optimize the cost and benefits of both.

From a pure infrastructure hardening perspective, Quanta Technology offers a number of activities that are employed in utility companies in various areas of the country and represent leading practices. All of the activities offer improvement in system strength against storms but should be pursued in a coordinated programmatic approach to optimize benefit for the investment. Following are some activities to be considered in a hardening program.

Damage analysis – a review of historical storm damage to the T&D system could be undertaken to identify any areas of the system that routinely experience infrastructure damage during storms. Common failure modes of the transmission system could be identified and analyzed. For example, outage reports indicate that approximately 75% of customer outage minutes on the transmission system are caused by trees, either on or off the right-of-way corridor. From a hardening perspective it can be determined if the outages are due to conductor down, poles down, tree in line with no conductor or pole down, etc. In short, specific details of outages can be examined to determine root cause and extent of damage to facilities. This analysis provides the necessary information to determine which potential damage issues should be addressed with priority and the extent of remediation needed to reduce damage probability. Concurrent with the damage analysis, a study of the location of outages, as currently included in the PSE initiatives, can be pursued. The damage and location information will provide valuable insight into the areas of priority to be addressed with any hardening initiative.

Structure analysis – the review of historical damage can, in addition to cause, examine the design strength and actual loading of any structures that failed. It is reasonably expected that all structures will meet minimum loading criteria as defined by applicable standards. The issue to be explored is whether or not the design can be enhanced for the specific location and application with intent to reduce likelihood of failure during severe weather events. The basic premise is that specific locations and applications may present opportunities to address structure strength given the history of damage or failures at the location.

System design – this is not a true "hardening" issue, however, a system review may reveal opportunities for placement of switches or other devices that can help in reducing impact of an outage due to facility damage. The strategic placement of opening points in the system, coupled with infrastructure hardening techniques, can provide an overall improvement in the ability of the system to withstand severe weather events and to isolate outages when damage does occur. In some scenarios, certain locations of the system may be designated as areas to be sacrificed in terms of damage in order to maintain the integrity of the overall system. Recommendations for new switches or other devices are included as part of the reliability roadmap.

Pole inspection and maintenance – pole inspection programs offer a coordinated approach to maintenance of the pole plant and provide data that can be analyzed to determine overall pole plant condition and any emerging risks associated with pole integrity. Many utilities in the country today have some sort of pole inspection program that provides for all transmission and distribution poles to be inspected visually, invasively, or both, on a prescribed schedule. The typical pole "test and treat" program includes excavation of the pole ground line to inspect the pole condition just below groundline, chemical treatment of the pole at groundline, and sound and bore tests to evaluate the internal condition of the pole. Additional program elements can include engineering load analysis to determine the pole loading capacity based on current condition and the existing load on the pole from existing equipment.

Formal pole inspection programs of this type are typically established on cycles of 10 to 12 years for poles that are a minimum of ten years old. Some companies are on cycles of up to 15 years for distribution poles. PSE initiated a limited scope transmission pole inspection program in 1999 based on a ten year cycle for the entire pole population. The inspection cycle was accelerated in 2002 resulting in completion of the ten year inspection cycle in approximately six years. The program has been inactive since that completion and is being reestablished beginning in 2008 as a more comprehensive scope test and treat program. Distribution poles at PSE have not been subject to a regular inspection program and Quanta Technology recommends that such a program be undertaken. Budget estimates are provided in this report for this recommendation.

Vegetation management – the PSE territory is one of dense vegetation. The utility is constantly challenged to maintain its rights-of-way in a manner that reduces the chance of system interruptions caused by vegetation. The company has instituted specific programs to address some of the challenges of the area and has enjoyed success with these efforts, e.g., TreeWatch. However, the geographic characteristics of the territory, along with political and environmental interests, prevent the company from obtaining the levels of right-of-way clearance that most utilities enjoy.

In spite of the challenges PSE is effective in its vegetation management efforts for normal operating conditions. In an effort to decrease the impact of vegetation in storm conditions, PSE is pursuing initiatives outlined earlier. They include a program to widen rights-of-way in areas where vegetation has regularly caused outages during storm conditions, expansion of the TreeWatch initiative to areas identified for widening, clearing and maintenance of access roads to transmission ROW along cross country line routes, and removal of all vegetation species in the ROW that will achieve a mature height of fifteen feet or more. Additional funding has been proposed for future years ($3 million/year) for inspection of rights-of-way, danger tree identification, and removal of trees outside the rights-of-way.

The actual widths used by utility companies vary based on many factors, including line design and availability of right-of-way along the particular route. Obviously, urban lines are likely to have narrow rights-of-way compared to suburban or rural lines due simply to availability of potential corridors for line construction. Typical utility right-of-way widths are shown in the following table:

TYPICAL RIGHT-OF-WAY WIDTHS

	Nominal Line-to-Line Voltage in kV				
	69	115	138	161	230
ROW Width, ft.	75-100	100	100-150	100-150	125-200

Source: RUS Transmission Line Standards

As part of the 2003 northeast blackout investigation and reporting, FERC issued a report in 2004 on vegetation management. This report included a survey of practice among 161 transmission owners regarding right-of-way width. The findings of utility practice are detailed in the following table.

Right-of-Way Width							
500 kV		345 kV		230 kV		Less than 230 kV	
Minimum Width (ft)	# of Companies	Minimum Width (ft)	# of Companies	Minimum Width (ft)	# of Companies	Minimum Width (ft)	# of Companies
Less than 125	4	Less than 75	6	Less than 75	40	Less than 50	51
126-175	21	76-125	36	76-125	36	51-125	41
176 >	13	126 >	30	126 >	30	126 >	7

Source: Utility Vegetation Management and Bulk Electric Reliability Report, Federal Energy Regulatory Commission, September 7, 2004

It is also noted that NERC Standard FAC-003-1 defines vegetation management responsibilities under the Electric Reliability Organization (ERO) requirements. This standard defines specific responsibilities, subject to audit, for each transmission owner in the development, execution and documentation of a formal Transmission Vegetation Management Program (TVMP). Part of the program includes development and documentation of line clearances and the documentation of the ongoing program to maintain those clearances.

Critical structure hardening – as stated earlier in this section, Quanta Technology believes a hardening program should begin with well-defined objectives, measurable outcomes, and methodologies to ensure optimization of the effort. At companies where extensive hardening has been considered, the planning includes identification of critical structures on both the transmission and distribution systems and analysis of methods that may be applied to strengthen those structures. Critical structures must be defined by the utility; however, they are generally defined as poles or structures that carry operation critical equipment. If these structures fail during severe weather events or for other reasons, system operating flexibility may be compromised and outage duration extended for more customers. A hardening approach that focuses on strengthening critical poles would typically include all structures that carry manual or automated switches, reclosers, capacitor banks, CellNet equipment, and critical underground risers. This category may also include structures supporting critical spans such as major road or waterway crossings.

Underground conversion – a common hardening strategy is to convert overhead lines to underground, thereby reducing the exposure to severe weather damage. Undergrounding would appear to be the ultimate solution when it comes to system hardening against severe weather conditions. However, several considerations must be taken into account during feasibility evaluation, including:

- Typical installation costs are high compared to overhead systems. For this reason, affected customers pay the differential between overhead and underground construction.
- Flooding can impact padmounted equipment.
- Uprooted trees can impact buried lines and padmounted equipment.
- Pole risers for underground distribution significantly increase the high wind effects on the pole.
- Underground facilities (especially padmounted) are vulnerable to damage during clean-up efforts (e.g., bulldozers)
- Restoration times for damaged underground facilities are greater than equivalent overhead systems.
- Rerouting and branching of underground circuits is typically more difficult than overhead circuits.

Studies done by regulatory agencies in other states, as well as industry associations, have shown that storm related outages on underground systems can be quite common with extended restoration times as compared to overhead. There are situations, however, where underground facilities may be a viable option as opposed to storm hardening an overhead line. Leading practices consider underground conversion as a hardening method for use in specific situations that meet the objectives defined as part of a comprehensive hardening program.

10.3 Summary

In order to conduct a coordinated and comprehensive hardening effort, PSE will need to perform some analysis of past storms. This analysis is needed to identify areas of the service territory that are particularly vulnerable to severe weather damage and to determine historical failure modes of infrastructure. Information gathered in this analysis will provide valuable input into how hardening should be approached on a system-wide basis.

A comprehensive hardening program will include well-defined objectives, measurable outcomes, and methodologies to ensure optimization of the effort. If PSE desires to develop a hardening program, a systematic approach consistent with industry leading practices will include these elements as well as evaluation of various hardening tools and techniques. Hardening tools and techniques may include stronger poles, shorter spans, storm guying, undergrounding, reconductoring, or new materials. Application of these tools and techniques would be based on the identification of critical structures, critical customers, and critical circuits.

Finally, operational programs such as vegetation management and pole inspection and treatment must be a significant element of any infrastructure maintenance program. PSE's efforts to widen transmission line rights-of-way and to remove danger trees have proven successful for PSE over recent years. Expansion of these efforts through additional funding is indicative of the company's recognition of the importance of the program. Reestablishment of transmission ROW access points should be a priority in order to lessen the time required for response to physical damage along cross country rights-of-way. Establishment and execution of a formal pole inspection and treatment program for both transmission and distribution will enhance the company's effort to ensure that infrastructure is properly maintained and capable of with-standing severe weather conditions that are common to the area.

11 Conclusions

A reliability roadmap has been developed for PSE that will enable them to reduce overall system SAIDI by 50% while making significant improvements in all counties. The cost of the reliability roadmap is estimated to be $83,077,000 over ten years. This roadmap also calls for an increase in the PSE storm hardening budget of $75,431,000 (driven mostly by a wood pole test-and-treat program). This results in a net incremental spending increase of $158,508,000, or about $15.9 million per year over ten years. These numbers are not allocated to any specific year and are not adjusted to include inflation.

The reliability roadmap is aggressive, calls for a variety or reliability improvement initiatives, and requires a substantial investment. However, Quanta Technology is confident in the cost estimates, the reliability improvement estimates, and the ability of the roadmap to be implemented.

The underlying assumption was that this roadmap would be implemented over ten years. However, the roadmap can be accelerated or slowed down as desired, with costs and benefits adjusting accordingly. In addition, the roadmap provides costs and benefits of each reliability improvement category separately and for each county. This allows PSE to select parts of the roadmap for a more targeted yet cost effective approach if desired.

This roadmap is based on a high level analysis and required many assumptions. When reliability improvement plans are developed for specific feeders and groups of feeders, the overall mix of improvement projects described in the roadmap may or may not be applicable. PSE is encouraged to base specific reliability projects on predictive reliability models similar to the pilot study analysis detailed in the report. If this approach is pursued, PSE has a good possibility of exceeding the roadmap reliability improvement targets and significantly improving reliability for its customers is a defendable and cost justified manner.

Appendix A – Reclosing and Overcurrent Protection

Distribution system protection has a major effect on customer reliability. Some protection practices can have a significant impact while costing virtually nothing to implement, while others may require the utility to spend considerable amounts of dollars to achieve the desire levels of system performance. This section addresses some of the overcurrent protection areas which can help achieve the goal of improving reliability performance of PSE.

Fuse Save vs. Fuse Blow

Historically, one of the primary purposes of reclosing, was to save the fuse during temporary fault conditions. It has been well known that in high fault current areas (approximately 4kA depending on fuse size and type), it was impossible to save the fuse since the fuse was simply too fast (.5 cycles) and hence could not be saved even by the fastest breaker or recloser (after you get about a mile or 2 from the substation, it is usually possible to save the fuse).

We have seen much of the industry, including PSE, reassess their overcurrent coordination practices, on overhead systems, in an effort to address power quality issues (momentaries). There are now essentially 3 approaches that utilities use:

1. **Fuse Save** – This approach makes the attempt to minimize customer interruption time (reduce SAIDI) by attempting to open the breaker or recloser faster than it takes to melt the fuse. This saves the fuse and allows a simple momentary interruption....a blink. For most systems, this works pretty well. In high short circuit areas, it may not be possible to make this approach work.
2. **Fuse Blow** – The approach here is eliminate the fast trip of the breaker or recloser and have the fuse operate for all permanent and temporary faults. This is the approach apparently being used by PSE. The purpose of this scheme is solely and entirely to minimize momentary interruptions. This scheme is very successful in high short circuit areas where a "fuse save" approach didn't work anyway. The downside of the "Fuse Blow" concept is that it increases SAIDI, i.e. in an effort to increase power quality (momentaries), we decrease reliability.
3. **Both** – Many utilities use both schemes for a variety of reasons:

- Fuse Blow for high short circuit current areas and Fuse Save where it will work.
- Fuse Save on overhead and Fuse Blow on underground taps
- Fuse Save on rural and Fuse Blow on urban
- Fuse Save on stormy days and Fuse Blow on nice days.
- Fuse Save on some circuits and Fuse Blow on others depending on customer desires

Although there has been a lot of discussion on this in the industry, it was unclear as to what utilities were actually doing these days. The following informal survey, performed by Quanta engineers, addressed the status of the industry on this topic. As can be seen from the survey, over 80% (78 out of 95) of the utilities reporting indicated they still use a "fuse save" philosophy on some portion of their system.

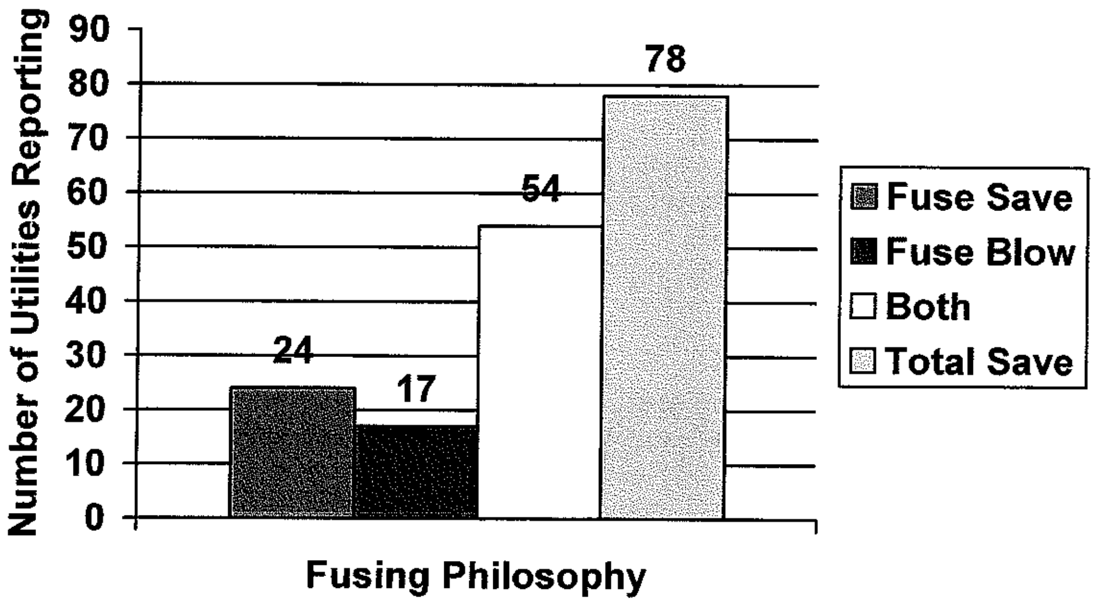

Figure A1. Fusing Philosophy Survey

Many utilities have systems with high short circuit levels are using fairly fast fuses (e.g. 65K) on their lateral taps. As shown below, this common type fuse cannot be saved unless the short circuit current seen by the fuse is 735 amperes or less (assuming a 5 cycle breaker, a 1 cycle relay time and the damage curve of the fuse). PSE uses T link fuses which are slower than the K's. Most of the T links used are 65T and below. The plot below shows that the limit of coordination for this fuse is about 1310 amperes. For most utilities feeders, a fault level below 1310 amperes is only achieved when the fault is approximately 7 or 8 miles from the substation. Having a "fuse blow" scheme usually results in decrease in MAIFI and an increase in SAIDI. However, since the fuse size is generally very small and the lines are relatively short, the "save scheme" would probably not work anyway. A possible solution to this dilemma would be to go to a slower fuse. This can be done by either changing the fuse type or increasing the fuse rating. The same figure shows the impact of going to something like a 100KS. Using this fuse, coordination is attained up to approximately 2900 amperes (about 2 miles from a typical substation).

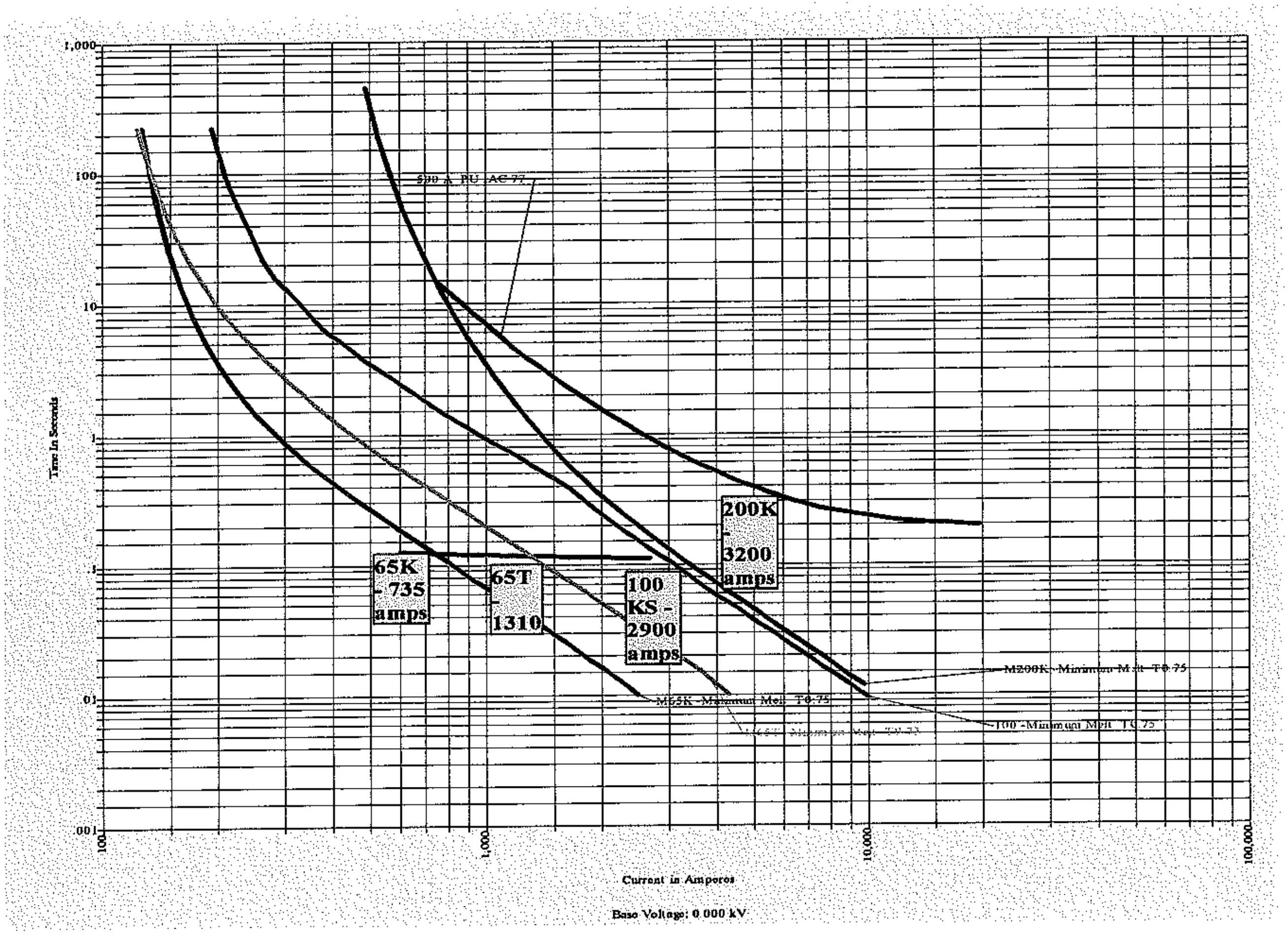

Figure A2. Impact of Fuse Size and Type on Coordination

The table, shown below, illustrates the impact of total interrupt time. A typical minimum interrupt time for a feeder breaker is about 6 cycles, which accounts for the relay time (1 cycle) and the breaker time (5 cycles). By using faster reclosers and breakers, as well as large fuse sizes, it is possible to achieve "fuse saving" beyond 5000 amperes Some utilities use 200 ampere fuse ratings and KS or T fuses to achieve these high levels of coordination.

Table A1. Effect of Interruption Time

Breaker/Recloser (total interrupt time in cycles)	65K	200K
2	1500	5962
3	1148	4700
4	1061	4334
6	813	3595

One technique used by a number of utilities is to use both a "fuse save" philosophy in lower short circuit areas and a "fuse blow" philosophy in high fault current areas. This scheme has a number of advantages since it both reduces MAIFI as well as SAIDI. SAIDI can be reduced since the midline device is normally faster (3 cycles) than a feeder breaker (6 cycles) and can be coordinated with the fuse in higher short circuit area (see table above). Another advantage is that it reduced the number of customers who are out of service for a permanent fault at the far end of the feeder It is understood that PSE utilizes some reclosers on the feeders so this scheme could be implemented quickly and with little cost.

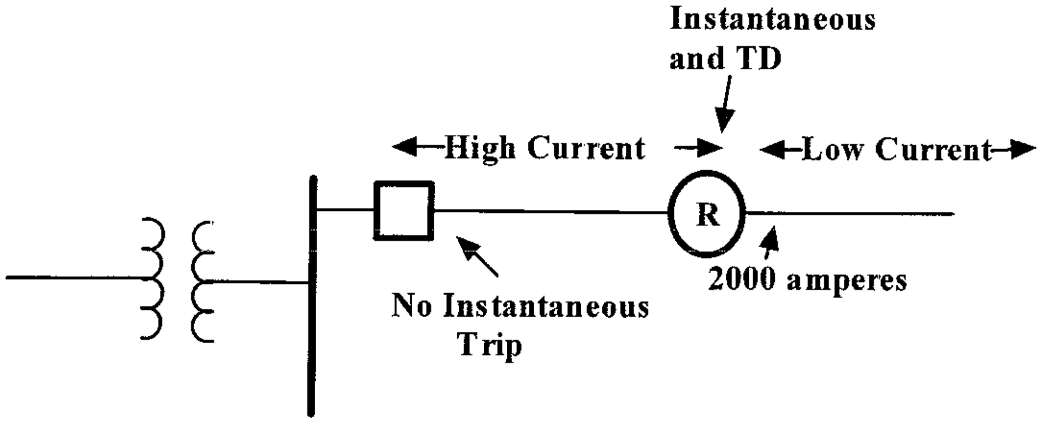

Figure A3. High/Low Scheme

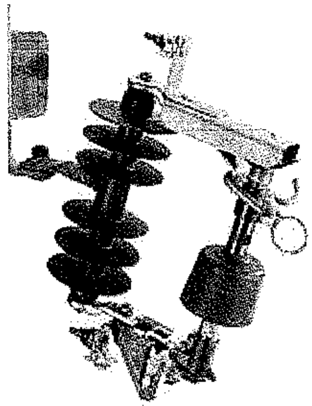

Figure A4. Sectionalizer

A device that PSE could use in high short circuit areas, where fuses will not coordinate, is a sectionalizer. These devices have no time-current curve and simply count the operations of the reclosing breaker or recloser. They interrupt during the "dead time" of these devices so they do not have to interrupt current. The drawback to sectionalizers is that they require multiple reclosing, which causes momentaries.

Automation

Certainly automation (in various forms) has been around for many years. One of the biggest hurdles to an automated distribution system was the ability to adapt to new configurations as the system grew New automation offerings, like the S&C IntelliTeam approach, is a modular system that used distributed intelligence and peer-to-peer communication to dynamically track system conditions and provide isolation and service restoration. Some of the features that make these new systems attractive are:

- Scaleable
- No limit to the number of controls in the circuit
- Logic is programmed in
- Priority sections can be designated
- Automatic reset to normal when voltage is return to normal

Results of from the reliability study indicated that for the "Pilot System" the use of automation could achieve an average reduction in SAIDI of approximately 18%, at a cost of approximately $25,000 per new switch.

Figure A5. Hi-Tech Automation Switch

Reclosers

After fusing the laterals, probably the most effective overcurrent device to improve reliability is the re-closer. It is understood that PSE uses reclosers on some of their feeders but is not using them to "fuse save". Reclosers have been around a long time but, for the most part, they were only utilized when the "reach" of the breaker was inadequate. Many were also used for small rural substations where loads and short circuit levels were low enough to allow the reclosers to be used in place of the feeder breakers. The newer reclosers have considerably higher ratings as well as multiple relay functions and PQ monitoring capability and can consequently be considered in much larger substation. Results of the pilot study analysis indicated that reclosers can improve SAIDI about 14% in a non-automatic loop scheme.

Many utility engineers are intimidated by putting another device, like a recloser, out on the feeder due to coordination issues. The figure below illustrates a standardized "fuse save" approach to automatic loop schemes using the following assumptions:

- Lateral fuses are generally 65K or higher A 65T would be such a fuse.
- Feeder faults are generally above 600 amperes. PSE feeders appear to normally be relatively short so this should not be an issue
- Feeder reclosers are generally applied at feeder locations where the maximum fault level is less than 4,000 amperes.
- Coordination is impossible near the substation due to the relative speed of the fuse and breaker (recloser).

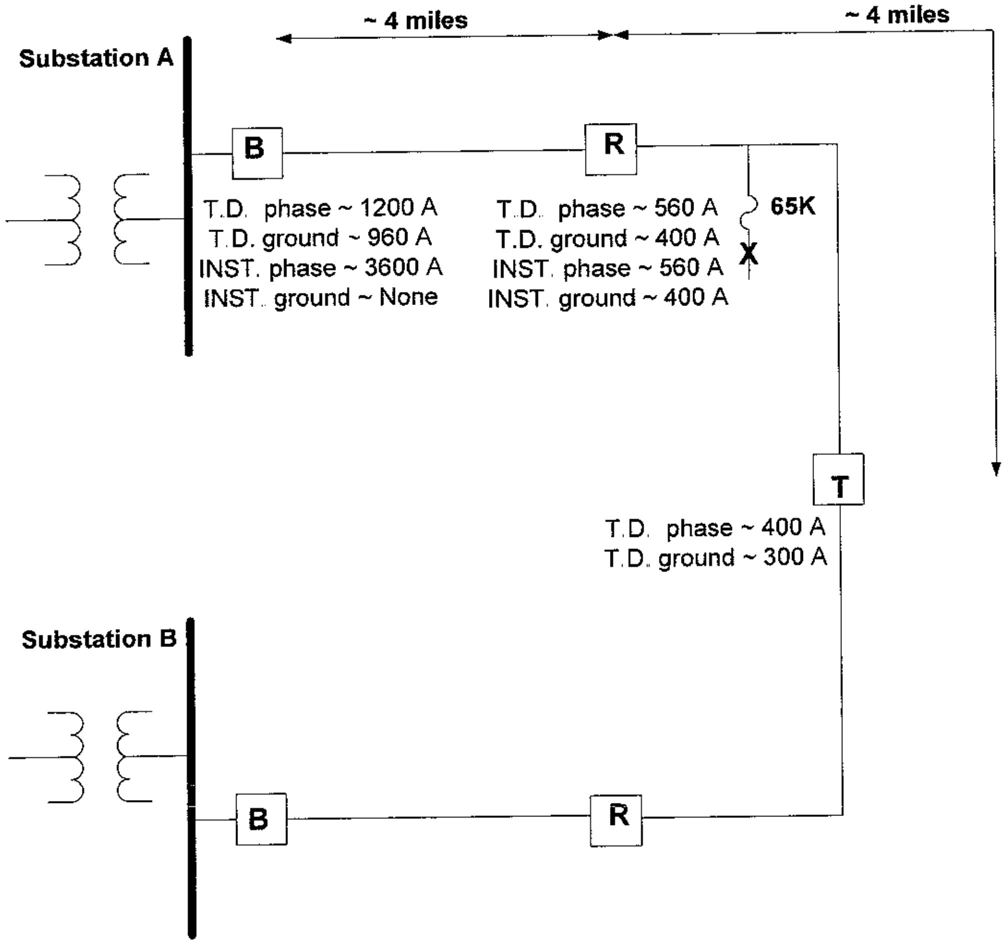

Figure A6. Standardized Settings for Reclosers

In reality, most distribution systems (using line reclosers) have similar characteristics. Most are 4-wire-multigrounded, are relatively long (>5 miles) and have short circuit levels, at the substation of about 10,000 kA. Most have the majority of their 3- phase feeder overhead. Load levels are generally limited to 600 amperes or less with the loads fairly distributed on the circuit. Most have a normally open loop. With this in mind, Figure #6 shows the general template for this typical distribution system.

The benefits of using reclosers and the ability of the newer reclosers to perform single phase switching is shown below. These times refer to those outages associated with the feeder main. Outages from lateral faults would not be affected by these designs, except that "saving the fuse" would tend to be more successful due to the settings of the additional devices.

Table A2. Effect of Reclosers on Feeder Main Reliability

	SAIFI (/yr)	SAIDI (hr/yr)
Base Case (no line reclosers)	1.6	3.3
Add Midline Recloser	1.2	2.6
Add Loop Recloser	1.0	2.1
Allow Single Phase Switching	0.8	1.8

Sequence Coordination

Some utilities use a feature on the electronic reclosers called "sequence coordination". This feature is used to improve service continuity for reclosers in series. The problem with recloser-to-recloser coordination in the standard mode is that the time-delayed operation of the downstream unit can take long enough to operate the upstream unit on its instantaneous trip mode. The purpose of sequence coordination is to prevent unnecessary fast trips of the back-up recloser (or digital relay) for faults that can be cleared by the downstream recloser. This approach could be used on PSE's longer feeders, if a "fuse save" approach is adopted some time in the future. In sequence coordination, the back-up recloser merely counts the fast trip operations of the downstream reclosers but does not trip. Its programmed sequence is then advanced to its time delayed operations. In its time-delayed mode, the back-up recloser can usually be coordinated with the time-delayed trips of the downstream unit.

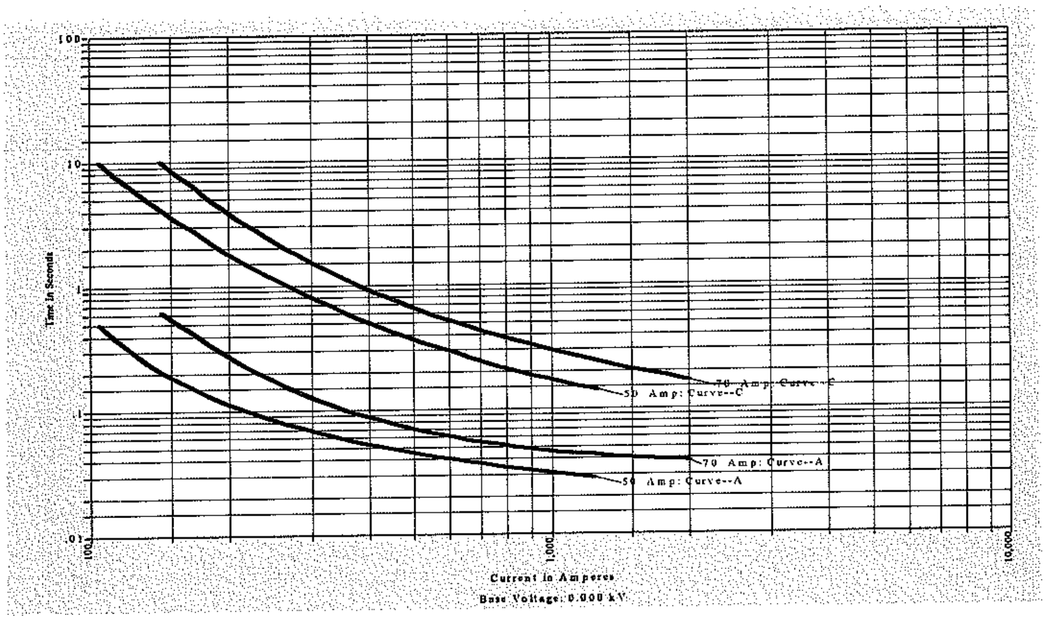

Figure A7. Sequence Coordination

Single Phase Tripping

Single-phase operation of the recloser is possible with the new electronic reclosers, shown earlier in the report, and should be considered by PSE in the future. Single-phase operation of the recloser is simple since virtually no settings have to be changed. Lockout can be either single-phase or three-phase depending on preference. Some utilities have decided that single-phase lockout is preferred unless it causes excessive neutral current. Locking out for any condition where the pre-fault load current exceeds 200 amperes on any phase can easily mitigate this condition. Single phasing should not be a problem for residential customers. For commercial and industrial customers, standard policy at most utilities has always been that they are responsible for their own protection against single phasing.

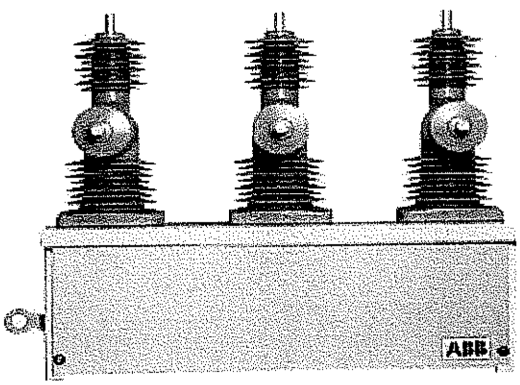

Figure A8. Electronic Recloser

Lateral Fuse Philosophy

Fusing all taps off the 3 phase main is a must (regardless of length). There is no single industry philosophy when it comes to lateral fusing but there are a number of trends and observations that can be mentioned which are as follows:

- **Standardized Fuse Size.** Most utilities pick a fuse size, a 65K seems to be the most popular, and use it for virtually all their lateral taps. These utilities are obviously not fusing on the basic of line loading. The reason given is that it's easier for the crews to deal with one size. What it also says is the lateral loads are not really important and coordination is spotty.
- **Feeder Selective Relaying (FSR or "fuse saving") / Coordination.** Some utilities pick a fuse size to allow maximum coordination with the breaker or recloser (slow the fuse to allow breaker or recloser to clear temporary faults). Utilities using 100 or 200 ampere lateral fuses might be doing it for this reason and not because of lateral loading. It is a common and successful practice for many utilities.
- **Load Level.** Some utilities fuse laterals depending on load. PSE appears to use this philosophy. You can sometimes tell this because lateral fuse sizes vary considerably, and size is not a function of short circuit level (higher fuse sizes near the substation might indicate an attempt to coordinate). Fuses used for laterals should be rated at least twice the lateral load to allow for cold load pickup, inrush, and emergency back-feed. It should be noted that fusing of laterals does little if anything to prevent overload. Fusing philosophy, here, is to take out the fault not protect for overload. Where lateral fuse sizes are still less than 25K or a 15T, there is often a problem with lightning current blowing the fuse. Most lateral fuse operations during lightning storms, however, are caused by line flashover (fault current), which will operate and fuse size. Fusing a lateral on the basis of load makes sense if there is a conductor burn down problem. This should be a rare consideration on the newer designs. On some of the older construction, using small conductors, there is little choice but to fuse as tightly as possible and this philosophy is probably the best. Small fuses on lateral taps have the advantage of operating for some high impedance faults and the disadvantage of being prone to nuisance operations due to inrush, emergency overload conditions, lightning and coordination with upstream protective devices. Small fuses make "fuse saving" very difficult, if not impossible on short feeders. The figure, shown below, illustrates the limits of coordination for some of the T links used by PSE. Approximately 85% of PSE links are 65T or below and will not coordinate above about 1398 amperes. The 100T will allow up to 2192 amperes and the 200 T up to over 6000 amperes. If PSE was to adopt a "fuse save" strategy, lateral fusing philosophy would have to be modified.

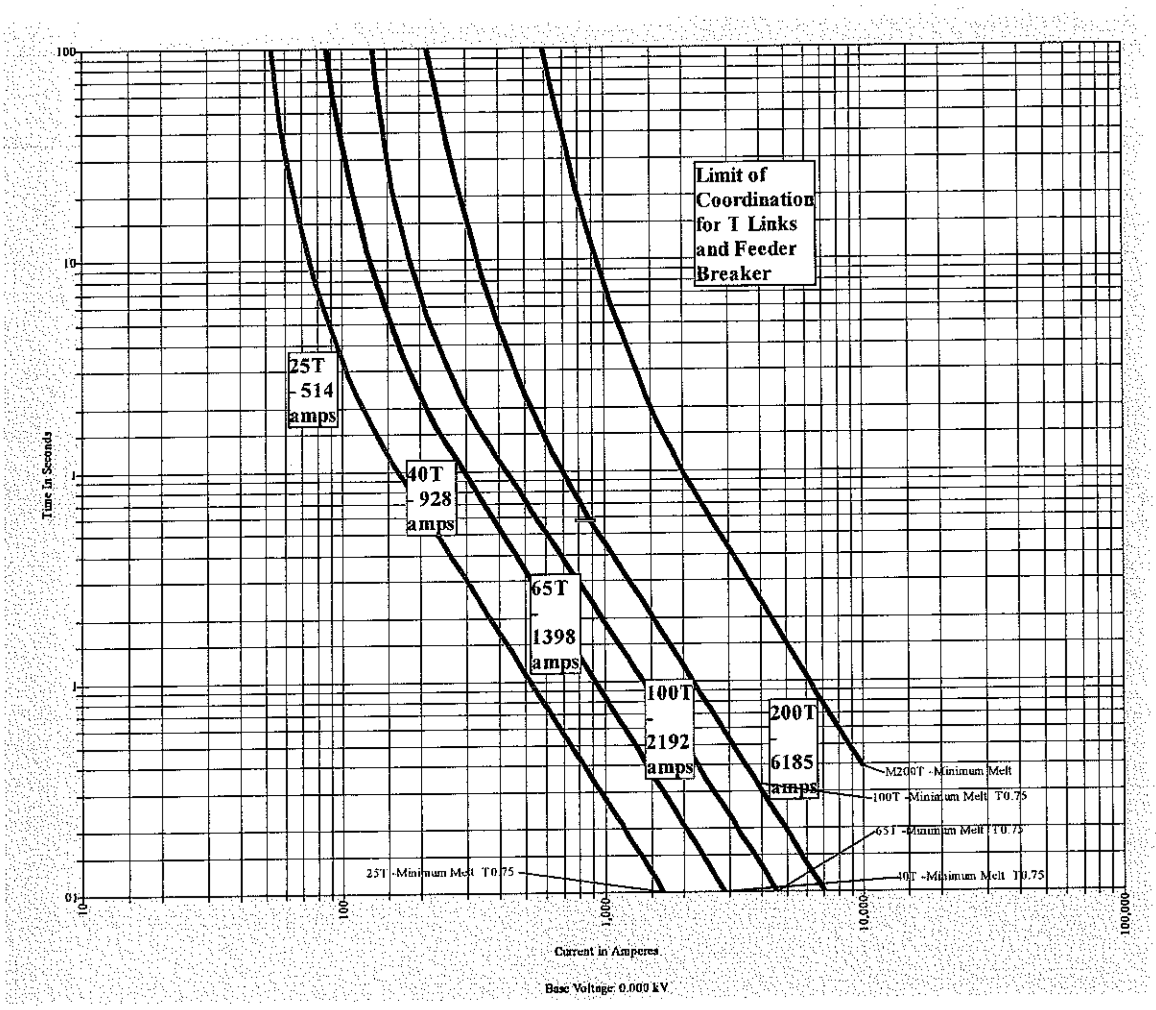

Figure A9. Limit of Coordination for PSE T-Links (5 cycle breaker and 1 cycle relay)

Distribution Transformer Fusing

The purpose of the primary fuse (using traditional arguments) is as follows:

- Isolate a transformer with an internal fault from the primary circuit so that only those customers served from the faulted transformer experience a service interruption. Ideally this isolation process will be accomplished such that the transformer does not fail in a disruptive fashion.
- Protect the transformer against the effects of through fault currents at and downstream from the secondary terminals of the transformer. Ideally the fuse should operate before the transformer is damaged thermally or mechanically.
- Protect, to whatever extent possible, the transformer for high impedance faults or arcing faults in the secondary circuits fed from the transformer.
- Coordinate with upstream protective devices

- Coordinate with downstream devices (secondary breaker), if any.
- Withstand lightning and inrush surges
- Withstand short time overloads

The "standard" methodology for minimum fuse selection is to plot the following three points and make sure the fuse damage curve is to the right hand side of these points:

1. On "Cold Load Pickup" point (3 times full load for 10 seconds)
2. Two Inrush Points:
   - 12 times full load for 0.1 seconds
   - 25 times full load for 0.01 seconds

Most utilities recognize that the transformer fuse is really intended for 2 major things:

- Separate a failed transformer from the system to minimize its impact on other parts of the system
- Keep the cover from blowing

Utilities using "standard methodology" for transformer fuse selection, as PSE apparently does, will normally find that they have a very high incidence of nuisance fuse operations (due to lightning and multiple inrush currents) because the fuses are too small. Many utilities subscribe to the "philosophy" that the purpose of the primary fuse is to isolate the failed transformer from the rest of the system and "keep the lid on". Secondary faults are considered to be "self clearing" and protection of the transformer from overload is not a consideration. A much simpler approach which solves a lot of the problems associated with the traditional approach is to choose a fuse size that is 2 times or greater than the full load current of the transformer. This approach has the following advantages:

- It greatly reduces the number of nuisance fuse operations caused by multiple inrushes during reclosing (which the traditional practice does not do).
- It reduces the number of nuisance fuse operations due to saturation of the transformer caused by lightning.
- It minimizes the effect of inrush currents higher than those shown above.
- It's easy since it assumes that overload protection is not the purpose of the fuse, which is true.

PSE apparently does not use CSP transformers for most residential applications, which is good. The CSP transformer was introduced by Westinghouse in 1934. At that time the secondary and service conductors were open wires. The secondary breaker incorporated in the CSP transformers is able to clear secondary faults, which were not uncommon with open wire secondary conductors. Such secondary faults often have sufficient impedance to prevent their clearance by the transformer primary fuse. The CSP breaker was designed to open before heating could damage the transformer. This was significant because, before the introduction of the CSP units, open-wire secondary faults often resulted in transformer failure due to overheated windings. The secondary breaker also improved the overload protection for the transformer winding.

In present-day electric distribution utilities there are concerns about several features of the CSP transformer. These concerns involve economic, power quality, and safety factors. Both CSP and conventional transformers have wide acceptance. Studies of CSP's show the following:

- Additional load losses of CSP transformers
- Limited interrupting capacity of CSP internal weak-link fuses (usually less than 2000 amperes)
- Additional line outages due to animal contacts on CSP high voltage bushings. Transformers with internal fuse protection can cause animal contacts to be cleared by upstream devices such as tap fuses or line reclosers.
- Larger CSP transformers, 50 to 100 kVA, have weak-links which may require larger tap fuses than externally fused conventional units.
- Installed cost of a typical (25 kVA) transformer is almost equal for a CSP unit or a single bushing conventional unit with tank mounted arrester and an external fuse.
- Transformer load losses are 4 to 8% higher for the CSP, resulting in an approximately 8.5% life-cycle cost

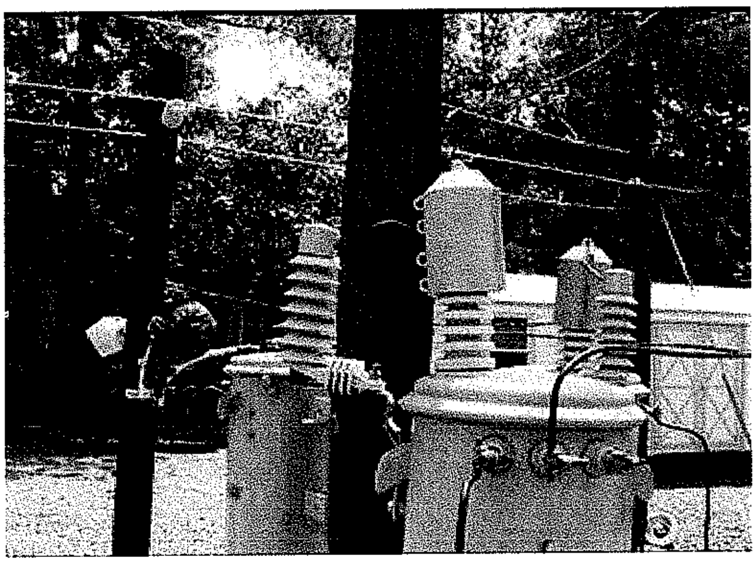

Figure A9. Distribution Transformer

Fault Impedance Pitfalls

PSE protection schemes are based on protection for low level faults. Some utilities use the standard default fault impedance of 40 ohms (or 30, 10 or 5) to account for minimum fault conditions. This method (not used by PSE) is incorrect. Data taken for the past 30 years has concluded that the fault impedance for a downed conductor is much higher, as shown below and hence these faults are not detectable with normal protective schemes. If the fault is detectable, there is no fault impedance, i.e. the lines either touch or arc to one another (bolted).

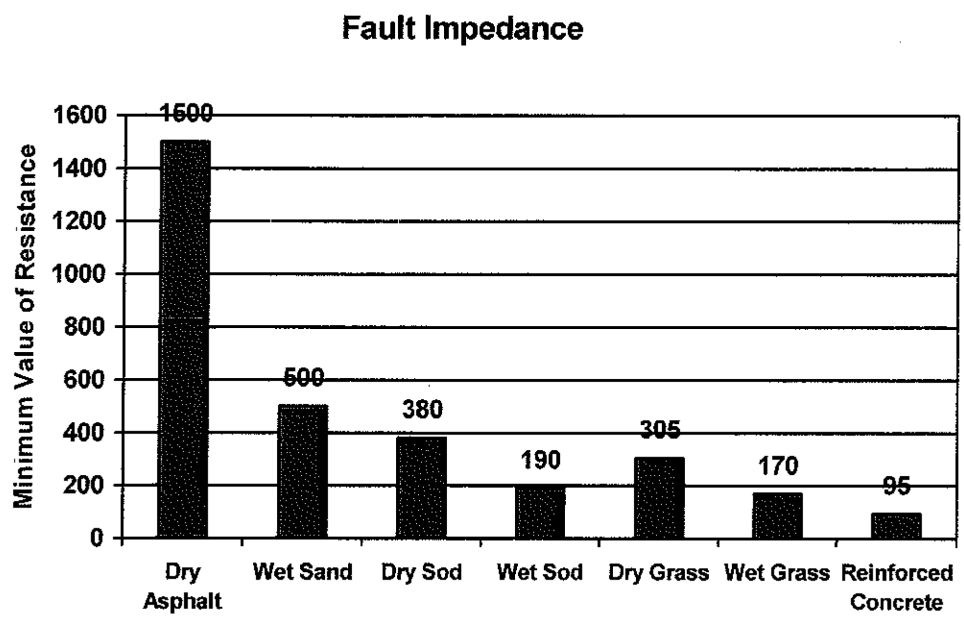

Figure A10. Fault Impedance for a Downed Conductor

Fault Recording Advantages

The ability of electronic reclosers and relays to record fault characteristics can go a long way in helping a utility find the proper overcurrent philosophy For example, a utility using 34.5 kV found that the instantaneous reclosing time was too short to allow the fault path to de-ionize on a temporary fault and solved this by adding a 1 second time delay Other utilities have found that cutting back on the number of reclosures does not negatively impact system reliability and protects equipment. Others have found that fault impedance is 0 ohms and eliminate any fault impedance from there calculations. Finally, many utilities have found that the available data allows them to locate faults. Utilities, like Progress Energy, report fault location accuracy of 80% within a 0.5 mile range, with the remaining 20% within approximately a mile (many feeders exceed 10 miles in length) Significant reductions in CAIDI have been achieved (Progress Energy indicates that CAIDI was reduced by 25%) as a result of this analysis. Also, analysis of data has been used to identify improper conductor spacing, malfunctioning protective equipment, protective equipment that did not coordinate, incorrect relay settings, areas needing vegetation management and animal mitigation, and feeders that were experiencing harmonic issues.

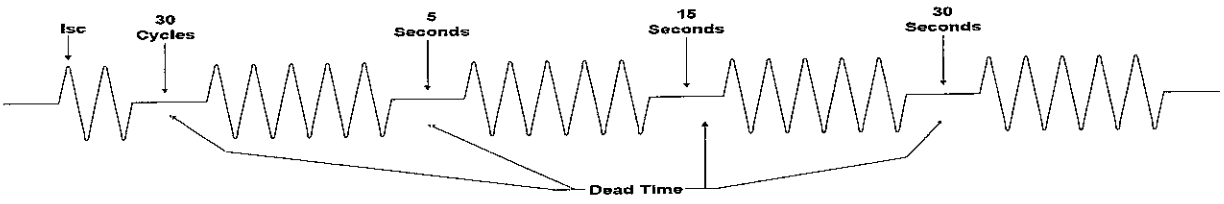

Figure A11. Typical Breaker Reclosing Sequence

TripSaver

One interesting new device that could have a significant impact on a utilities overcurrent protection practices is the TripSaver Dropout Recloser, manufactured by S&C. This device is made for laterals experiencing frequent momentary faults, accommodates a "fuse blow" philosophy The device can eliminate some of the sustained interruptions which can result when lateral fuses operate for temporary faults as well as momentaries to other parts of the feeder. The device will also eliminate the feeder momentary interruptions needed to save the lateral fuse during temporary faults This device, which essentially has the characteristics of a very fast single phase recloser may be ideal for PSE. The first opening of the device is 1.5 to 2 cycles (total clearing time). It has a 5 second reclosing time interval The second opening operation of the device uses a time-current characteristic equivalent to either a K or T speed fuse to allow it to coordinate with downstream fuses. It should be noted that the TripSaver interrupting rating is 4,000 amperes which is not sufficient for most areas within about a mile from the substation. It should also be noted that the instantaneous trip relay of the breaker or recloser would have to be delayed (a few cycles) to insure that it does not pick up during the 1.5 to 2 cycle clearing time of the TripSaver Instantaneous relays generally pick up in about 1 cycle.

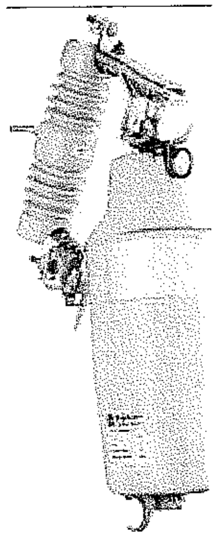

Figure A12. TripSaver Device to Reduce Both SAIDI and MAIFI

Fault Indicators

Fault indicators have been used for over 40 years and have proven to be effective when properly applied and purchased from a knowledgeable manufacturer. Generally, these devices are applied to single phase underground taps. Studies show they can improve the lateral contribution of SAIDI up to about 15% depending on URD design. When applied to URD, they are normally placed at each transformer. FCI's can also be used on 3 phase feeders both overhead and underground with some success. Results of the study on the pilot area indicated that an improvement of approximately 15 minutes was achievable with and investment in FCI's of approximately $4600 per feeder.

Figure A13. Faulted Circuit Indicator (FCI)

Appendix B – Typical PSE Feeder

Using system data supplied by PSE, and estimate of what a typical substation would look like was attempted. The figure, shown below, illustrates this typical feeder.

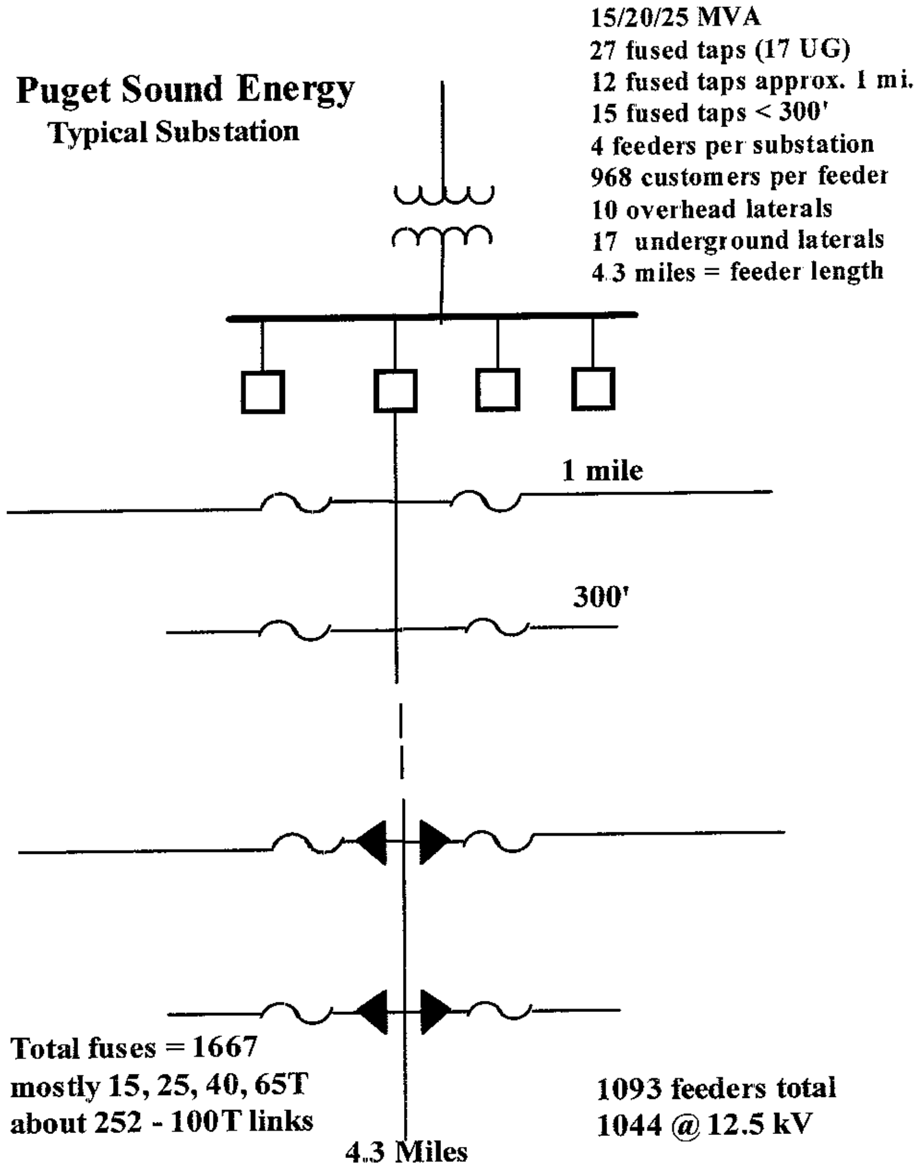

Figure B1. Typical PSE Feeder

Appendix C – Reliability Metrics

Reliability indices are statistical aggregations of reliability data for a well-defined set of loads, components, or customers. Most reliability indices are average values of a particular reliability characteristic for an entire system, operating region, substation service territory, or feeder. This section describes the most commonly used reliability indices, discusses the important issues of storm exclusion, and concludes with a discussion about benchmarking.

The reliability index definitions provided follow the IEEE standard 1366-2003. This standard has not been universally adopted by U.S. utilities, but is growing in popularity and provides a document to which individual utility practices can be compared.

C.1 Reliability Indices

The most widely used reliability indices are averages that weight each customer equally. Customer-based indices are popular with regulating authorities since a small residential customer has just as much importance as a large industrial customer. They have limitations, but are generally considered good aggregate measures of reliability and are often used as reliability benchmarks and improvement targets. Formulae for customer-based indices include (unless otherwise specified, interruptions refer to sustained interruptions):

System Average Interruption Frequency Index:

$$\text{SAIFI} = \frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}} \qquad \text{/yr}$$

System Average Interruption Duration Index:

$$\text{SAIDI} = \frac{\sum \text{Customer Interruption Durations}}{\text{Total Number of Customers Served}} \qquad \text{hr/yr}$$

Customer Average Interruption Duration Index:

$$\text{CAIDI} = \frac{\sum \text{Customer Interruption Durations}}{\text{Total Number of Customer Interruptions}} \qquad \text{hr}$$

SAIFI is a measure of how many sustained interruptions an average customer will experience over the course of a year. For a fixed number of customers, the only way to improve SAIFI is to reduce the number of sustained interruptions experienced by customers.

SAIDI is a measure of how many interruption hours an average customer will experience over the course of a year. For a fixed number of customers, SAIDI can be improved by reducing the number of interruptions or by reducing the duration of these interruptions. Since both of these reflect reliability improvements, a reduction in SAIDI indicates an improvement in reliability.

CAIDI is a measure of how long an average interruption lasts, and is used as a measure of utility response time to system contingencies. CAIDI can be improved by reducing the length of interruptions, but can also be reduced by increasing the number of short interruptions. Consequently, a reduction in CAIDI does not necessarily reflect an improvement in reliability.

The increasing sensitivity of customer loads to brief disturbances has generated a need for indices related to momentary interruptions. Two momentary indices have become standard. One is based on the frequency of momentary interruptions and the other is based on the frequency of momentary events. Formulae for these indices are:

Momentary Average Interruption Frequency Index:

$$\text{MAIFI} = \frac{\text{Total Number of Customer Momentary Interruptions}}{\text{Total Number of Customers Served}} \quad /\text{yr}$$

Momentary Event Average Interruption Frequency Index:

$$\text{MAIFI}_E = \frac{\text{Total Number of Customer Momentary Events}}{\text{Total Number of Customers Served}} \quad /\text{yr}$$

A momentary interruption is counted each time a short interruption occurs. A momentary interruption event is counted once for all momentary interruptions that occur within a short period of time (the IEEE standard is five minutes). If a short interruption or a sequence of short interruptions occur and are then followed by a sustained interruption, no momentary interruption or momentary interruption event is counted.

C.2 Exclusion of Storms and Major Events

When electric utilities compute reliability indices, they often exclude interruptions caused by storms and other major events. In the U.S., comparisons of reliability indices between utilities are difficult since more than 80% exclude major events but definitions of major events vary widely. Examples of major event definitions include:

- A severe storm, flood or civil disturbance that requires three or more days to restore service.
- The following criteria are met: (1) the National Weather Service has issued a severe watch or warning for the area. (2) Extensive mechanical damage has been sustained. (3) More than 10% of customers are out of service at some time during or immediately after the storm. (4) At least 1% of customers are out of service 24 hours after the beginning of the storm.
- An event resulting in more damaged sites than available crews to be dispatched to these sites.
- A certain percentage of customers in a specific dispatch area experience an interruption.

There are differing views about the appropriateness of excluding major events from reliability index calculations. From a customer cost perspective, it should not matter whether interruptions occur during mild or severe weather and reliability targets should be set to maximize societal welfare. From a utility perspective, distribution systems are not designed to withstand extreme weather such as earthquakes, floods, forest fires, hurricanes, ice storms and tornadoes. Since doing so would require substantial rate increases, reliability measurements and improvement efforts should focus on non-storm performance. In addition, customers tend to be more tolerant of interruptions during severe weather since the cause of the interruption is apparent and utility response is highly visible.

C.3 IEEE 2.5 Beta Method

Since utilities have a wide range of approaches to storm exclusion for normal reliability index calculation, reliability index comparisons across utilities can be confusing. To address this concern, the IEEE has recommended a statistical-based approach to storm exclusion in Standard 1366. A utility, of course, is free to compute reliability indices using its traditional storm exclusion criteria, but the IEEE recommends that a utility also compute indices with its proposed approach for benchmarking purposes.

The IEEE storm exclusion process as detailed in Standard 1366 is called the "2.5 Beta Method." This is because the exclusion criterion is based on the lognormal parameter beta. [Note: Standard 1366 does not used the term "exclusion." Rather, it suggests that interruptions associated with an identified major event be classified as such and separately analyzed. Of course, this data is still effectively excluded from non-storm reliability index calculations.]

The 2.5 Beta Method works by classifying each day as either a normal day or a major event day (MED). A major event day is a day in which the daily system SAIDI exceeds a threshold value, T_{MED}. Even though SAIDI is used to determine the major event days, all indices should be calculated based on removal of the identified days.

The threshold value of T_{MED} is computed at the end of each year for use in the following year. The process of computing T_{MED} is as follows:

<u>Major Event Exclusion Using the 2.5 Beta Method</u>

1. Collect the last five years of historical data including the daily SAIDI for each of these days.
2. Throw out all days that did not have any interruptions.
3. Take the natural logarithm for each remaining daily SAIDI value.
4. Compute the average value of these natural logarithms and set this equal to alpha (α).
5. Compute the standard deviation of these natural logarithms and set this equal to beta (β).
6. Compute the major event day threshold: $T_{MED} = \exp(\alpha + 2.5\ \beta)$
7. Any day with a daily SAIDI greater than T_{MED} that occurs in the future year's reporting period is classified as a major event day and not included in normal reliability index calculations.

The 2.5 Beta method has been carefully formulated based on a balance of simplicity and actual results for a large body of historical utility data. Essentially, the IEEE found that utility SAIDI days, for the most part, follow a lognormal distribution. When utilities identified the days that they would consider major events based on other criteria, it was found that these days generally fall above the 2.5 Beta threshold point as described above.

The 2.5 Beta method is intended to be applied to a specific area to identify when the operational response to this area is stressed. Therefore, the same area used to compute T_{MED} should be the area tested for exclusion. The value for T_{MED} should not be computed for a large area and then used as the threshold for a smaller area. This is because SAIDI volatility increases for smaller area, resulting in a larger number of exclusions than intended by the methodology.

In the past several years, PSE has been computing T_{MED} for the entire system and then using this threshold for county-level exclusions. That is, if the daily SAIDI for a county exceeds T_{MED}, the day is excluded for that county. These numbers are potentially useful for PSE, but cannot be fairly compared to other utilities or used for benchmarking purposes. Therefore, PSE has recomputed SAIDI for all counties using the entire system to compute T_{MED} and using total system daily SAIDI to identified excluded days. Using this method, all counties have the same excluded days. These values are in the roadmap for benchmarking and target setting.

QUANTA TECHNOLOGY

Appendix D – Project Team

The Quanta Technology project team that produced this report includes the following:

Primary Team Members
Richard Brown, Technical Lead
James Burke, Overcurrent Protection and Reclosing
Luther Dow, Aging Infrastructure
Edmund Phillips, Reliability Modeling
Julio Romero Aguero, Reliability Modeling
Bill Snyder, Storm Hardening
John Spare, Roadmap Development
Robert Uluski, Automation
Le Xu, Historical Data Analysis

Richard Brown, PhD, PE. Dr. Brown is Vice President of Operations for Quanta Technology and also serves as an Executive Advisor. His areas of expertise are power system reliability, performance improvement, and asset management. He has published more than 80 technical papers in these areas, is author of the book *Electric Power Distribution Reliability*, and has provided consulting services to most major utilities in the United States and many around the world. Dr. Brown has been on the leadership team of three successful startup businesses. He is an IEEE Fellow, vice-chair of the IEEE Planning and Implementation Committee, and a registered professional engineer. Dr. Brown has a BSEE, MSEE, and PhD from the University of Washington, Seattle, and an MBA from the University of North Carolina, Chapel Hill. Over his 18 year career, Dr. Brown has worked (chronologically) at Jacobs Engineering, ABB, KEMA, and Quanta Technology.

James Burke. Throughout his career spanning over forty-one years, Mr. James Burke has advised a large number of electrical utility customers worldwide and has been a prolific author and instructor in the area of power distribution engineering. Mr. Burke has taught thousands of students throughout the world, has authored over 100 technical papers (including 4 prize papers), and is author of the book Power Distribution Engineering: Fundamentals and Applications, now in its 13th printing. Mr. Burke is a Fellow of the IEEE, and has chaired many key IEEE Working Groups, Task Groups and Subcommittees pertaining to voltage quality, overcurrent protection, neutral grounding, and faulted circuit indicators. He is the recipient of several prestigious IEEE awards including both the "Distribution Award for Excellence" in 1996 and the "Herman Halperin Award for Transmission and Distribution" in 2005. Mr. Burke received his BSEE from the University of Notre Dame, his MSIA from Union College, and is a graduate of the General Electric Power Systems Engineering Course (PSEC).

Luther Dow, PE. Mr. Dow has extensive electric utility engineering and operating experience. His areas of expertise are distribution planning, asset management, system condition assessment, and aging infrastructure management. He has been involved with and led numerous organizational and process change efforts. Mr. Dow has a BSEE and MBA from California State University, Sacramento and is a registered professional engineer. Over his 35 year career, Mr. Dow has worked at Pacific Gas & Electric, Doble Engineering, EPRI, and Quanta Technology.

Edmund Phillips, PE. Mr. Phillips has expertise in areas such as Power Generation, Distribution and Transmission system operation, and System Stability. He recently held the position of Systems Engineer where he coordinated both transmission and distribution system operations and planning. He also held the position of Project Manager, where he was instrumental in designing/building Automatic Voltage Regulators for Power Companies both in North and South America. Edmund received his BSEE and MSEE from Florida International University, and is both Licensed Professional Engineer and NERC certified.

Julio Romero Aguero. Dr. Romero Aguero is an expert in knowledge-based modeling and computational intelligence applications in distribution systems. He has over 11 years of experience in operation, maintenance, regulation and planning of distributions systems. He is the author of the first publication on type-2 fuzzy logic applications in distribution systems. In Honduras, he was Commissioner at the Electricity Regulatory Board, Distribution Operations Manager at the National Power Utility, and Adjunct Professor at the Department of Electrical Engineering of the National University. He is a Senior Member of IEEE, and former Chairman of IEEE Honduras Section. He is ex-grantee of the German Academic Exchange Service (DAAD), author of several technical papers and presentations, and a reviewer of international journals and conferences.

Bill Snyder. Mr. Snyder has a unique background in utility operations, management and change initiatives resulting from over 28 years experience in the electric utility industry. He has successfully led consulting engagements to review and evaluate operational processes and standards, conducted evaluations of asset condition and value, and led major process change identification and implementation programs in the engineering and operations functions. His experience in power engineering and his understanding of management needs and challenges to continuously improve operational performance provide him a unique insight into utility company operations, culture and improvement opportunities. As both a utility manager and as a consultant, he has experience working with senior officers to develop and implement operational strategy to achieve new levels of operational efficiency, service reliability and cost savings. Bill earned a BS degree in Engineering from North Carolina State University and MBA degree from Wake Forest University and is a member of IEEE.

John Spare, PhD, PE. Dr. Spare specializes in power distribution planning, reliability engineering, and underground systems. He was with PECO Energy for 22 years serving as a senior generation/transmission/distribution planner, having the responsibility for corporate load forecasting, spatial load forecasting and its use in distribution system planning, and as a supervisor of distribution reliability engineering. Before joining Quanta, he had been consulting for 12 years with KEMA, working on UG urban-core power systems, distribution planning and distribution performance projects around the world. Dr. Spare has a BSEE from Carnegie Mellon and MSEE and PhD-EE degrees from the University of Pennsylvania. Dr. Spare is a Senior Member of the IEEE and 20-year member of its Distribution Planning Working Group. He is registered professional engineer in Pennsylvania

Robert Uluski, PE. Throughout his thirty-four year career, which included positions with New England Electric System (now National Grid USA), KEMA, and EnerNex Corporation, Mr. Uluski has advised a large number of North American and international electrical utilities on a broad range of issues pertaining to the planning and implementation of substation automation, distribution feeder automation, and automatic metering. Mr. Uluski is a widely recognized expert in developing the business case for electric utility automation, and has developed software tools for analyzing the costs and benefits of these investments. He has authored dozens of technical papers on the topic of T&D automation and has conducted numerous seminars on the topic at leading