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I. Introduction

Q. Please state your names and positions with Portland General Electric (PGE).

A. My name is Stephen Hawke. I am Senior Vice President of Customer Service and Delivery. My name is Bill Nicholson. I am Vice President of Distribution. Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to explain PGE's 2011 test year Transmission and Distribution O&M expenditures, and how they support PGE's goal of adding customer value through operational excellence and improvement.

Q. Please summarize PGE's Transmission and Distribution O&M costs and capital expenditures from 2008 through the 2011 test year forecast.

A. Table 1 below summarizes this information:

Table 1
Summary T&D Changes ($ Million)

	2008 Actuals	2011 Test Year
Transmission O&M Expenses	$10.8	$12.6
Transmission Capital Expenditures	$39.7	$8.1
Distribution O&M Expenses[1]	$69.3	$84.1
Distribution Capital Expenditures[2]	$127.1	$140.6

The amounts, reflected in Table 1 as capital expenditures, represent capital expenditures for the year. The amount of an expenditure that closes-to-plant in a specific year is presented in PGE Exhibit 300.

Q. Please explain why PGE's Distribution O&M increases significantly from 2008 to 2011, by approximately $14.8 million.

[1] Actual costs for the Performance Management Group are normalized to reflect shift from Distribution to A&G with no change to PGE's corporate costs.
[2] Exhibit 300 (Revenue Requirement), Table 7 lists only core Distribution activities in the Distribution amounts for 2008 ($117.4 million) and 2011 ($138.8 million). Table 1 above, includes approximately $9.7 million in 2008 and approximately $1.8 million in 2011 that are activities included in the "Strategic" amount in Table 7.

A. PGE's Distribution O&M increase, between 2008 and 2011, is due to two major factors: 1) higher costs to restore service lines, in part due to the replacement of our insurance coverage for major storms; and 2) higher information technology (IT) costs. These two items are responsible for approximately $12.5 million of the increase. We discuss these and other increases in the Distribution section later in our testimony.

Q. How is the remainder of your testimony organized?

A. After this introduction, we discuss Transmission non-labor O&M and planned capital work in Transmission. In Section III, we discuss Distribution, beginning with goals and enhancements made to our technological systems. In this section we also provide an overview of cost increases in Distribution O&M; we discuss increases in our restoration expenses, Distribution IT, Tree Trimming, FITNES, and Locating programs, and the increasing costs in these programs. Our last section contains our qualifications.

II. Transmission

A. Transmission O&M Expenses

Q. Do transmission Full Time Equivalents (FTEs) increase from 2008 to 2011?

A. No. FTEs remain at approximately 27 from 2008 to 2011.

Q. Please identify the changes in non-labor O&M costs from 2008 to the 2011 test year forecast that are associated with Transmission.

A. Transmission non-labor O&M expenses increase by approximately $1.0 million, from around $5.4 million in 2008 to approximately $6.5 million in 2011.

Q. What accounts for the $1 million increase in non-labor Transmission O&M expenses?

A. There are two major drivers of the increased cost: 1) fees and use-of-facility charges, which are expected to increase by approximately $0.5 million, and 2) the first-year cost of the intertie insulator replacement program for the 500 kV lines, equal to approximately $0.5 million.

Q. Please discuss the increases in fees and use-of-facility charges

A. Fees and use-of-facility charges are expected to increase by approximately $0.5 million from 2008 to 2011 for three reasons:

- An increase in the Captain Jack Substation and AC Intertie use-of-facility charges - $0.2 million. The BPA use-of-facilitiy (UFT) charges for the Captain Jack Substation and the AC Intertie are increasing due to revised BPA assessments of the investment values of these facilities.
- Increased payments to Open Access Technology International (OATI) - $0.13 million. OATI's monthly fees are increasing with the addition of web accounting and dynamic scheduling capabilities to PGE's transmission management software. OATI supplies

PGE with an updated FERC/North American Energy Standards Board-compliant Open Access Same-Time Information System (OASIS) and transmission management software.

- Increased fees paid to BPA for substation work - $0.17 million. BPA is increasing the fees that PGE must pay for substation work at BPA's Grizzly, Malin, and Pearl substations.

Q. What does the $0.5 million expense for intertie insulators represent?

A. This is the first-year cost of a five-year program to replace insulators in our transmission system that are approximately 40 years old.

Q. Why is PGE initiating a program to replace intertie insulators on its 500 kV lines?

A. PGE has tested a sampling of the insulators on several of its 500 kV lines and found evidence of age-related insulator deterioration in a significant number of those sampled. During an extreme loading event, a portion of the insulators could become loaded beyond their current (reduced) capacity, which would result in significant outages. PGE has decided that a phased replacement program is warranted to maintain adequate reliability on the transmission system. The program will replace insulators on the Grizzly-Malin 500 kV line and Grizzly-Round Butte 500 kV line.

B. Transmission Capital

Q. What transmission-related capital work is PGE planning that affects the 2011 test year?

A. PGE is planning three major capital transmission projects: (1) the Transmission and Distribution Capacity Expansion Project, (2) the Oregon California Intertie Project, and (3) the Cascade Crossing Transmission Project. None of the expenditures for the Cascade

Crossing Transmission Project close to plant in the test year. Table 2, below, summarizes the capital expenditures for these projects for 2009 through 2011:

Table 2
Transmission Capital Expenditures ($ Million)[3]

	2009 Forecast	2010 Budget	2011 Test Year
Capacity Expansion Project	$9.0	$3.6	$3.9
Oregon California Intertie Project	$3.3	$7.3	$1.4
Cascade Crossing Transmission Project	$2.8	$5.4	$2.8

Q. Please explain the Capacity Expansion Project?

A. PGE's Transmission and Distribution Capacity Expansion Project is a multi-year project to address system needs by expanding and upgrading PGE's transmission system. This project is being implemented to comply with North American Electric Reliability Corporation (NERC) regulations and to provide capacity for continuing area load growth. PGE made major land purchases and completed the majority of the Willamette Valley Conversion in 2009. By 2011, PGE will complete the conversion of the Middle Grove substation to 115 kV in the Salem area. PGE will continue to incur expenditures associated with construction of 230 kV transmission for the new Horizon substation in Hillsboro as we make progress toward a 2014 completion date.

Q. Capital expenditures for the California Oregon Intertie (COI) project total approximately $12 million for the period 2009 through 2011. What will this project accomplish?

A. The COI project is a multi-year project to upgrade its capacity. The expenditures from 2009 through 2011 correspond to the agreed upon contractual payment schedule with BPA. The COI is currently rated at 4,800 megawatts, but it frequently operates at less than full capacity due to various operating constraints. When power flows exceed the COI's operational

[3] The capital amounts in the table represent capital expenditures for the year. The amounts that represent plant in rate base are presented in PGE Exhibit 300.

transfer capability, which is the industry threshold for safe and reliable operation, transmission transactions must be curtailed to reduce power flows to acceptable levels. The COI project will install new high-voltage equipment at several critical bottlenecks in the system. This equipment will reinforce the intertie so it can operate at full capacity more frequently, and under a wider range of conditions.

Q. Why is PGE considering the Cascade Crossing Transmission Project?

A. The Cascade Crossing Transmission Project will provide an East-West connection to existing and planned thermal resources and to existing or potential renewable resources east of the Cascades. In addition to this increased access, benefits include improved grid reliability and transmission needed to meet PGE's IRP energy goals.

Q. For 2009, 2010, and 2011, capital expenditures for the Cascade Crossing Transmission Project total approximately $11 million. What are these costs for?

A. The majority of the costs are for environmental assessments, permitting, licenses, and fees. The remainder is for public outreach and initial efforts to secure options on key properties. As indicated above, none of these costs closes to plant in the test year.

III. Distribution

A. Distribution Overview

Q. How does the OPUC measure/evaluate service quality at the Distribution level?

A. PGE submits annual service quality measure (SQM) reports, which contain outage and other results. The Commission Staff audits our SQM reports and enforces defined performance levels. Two of PGE's service goals–less than 1.0 outage, and less than 3.0 momentary outages–are the most stringent for investor-owned utilities in Oregon, and PGE consistently meets the OPUC weighted-average goals for those two measures. The target outage frequency goal (outages lasting 5 minutes or more) is no more than one per customer per year. The actual results have been less than one outage per customer, per year for the last four years. The target goal for momentary outages (less than 5 minutes) is no more than three momentary outages per customer per year. The actual results have been well below that for the last four years. PGE also annually reports the results of its System Average Interruption Index (SAIDI).

Q. What is SAIDI?

A. SAIDI is the total time during a year the average customer is without power, measured in minutes. It is an indicator of system reliability. All planned and unplanned interruptions of five minutes or more are included in the calculation. Major events are excluded. PGE's goal is fewer than 90 minutes.

Q. How are major events defined by the OPUC?

A. The OPUC definition of a "major event" means a catastrophic event that a) exceeds the design limits of the electric power system; b) causes extensive damage to the electric power

system; and c) results in a simultaneous sustained interruption to more than 10 percent of the metering points in an operating area.

Q. What are PGE's SAIDI results for the last four years?

A. In 2007 and 2008, PGE met its service quality goal of less than 90 minutes. However, in 2006 and 2009, PGE exceeded the 90 minute goal due to circumstances outside of its control.

Q. What events affected PGE's SAIDI outcomes in 2006 and 2009?

A. PGE had a number of storms in those two years that under the OPUC definition of major events could not be excluded from our results, since they did not result in a simultaneous sustained interruption to more than 10 percent of our customers. However, these storms were large enough to affect our SAIDI results.

Q. Is PGE recommending the adoption of a new service quality standard?

A. Yes. We recommend adoption of the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366-2003 reliability reporting standard for SAIDI.

Q. How does the IEEE 1366 reliability standard distinguish between outages that occur on "normal" days and major outages?

A. The standard sets a threshold value for daily system SAIDI. On any day, if the accrued SAIDI minutes exceed the threshold, that day is considered a major event day (MED) and is analyzed separately from events occurring on days that are not MEDs.

Q. Why does PGE want to adopt this reliability standard?

A. PGE faces two challenges: providing reliable service on an "every day" basis and responding to major events that threaten overall system integrity. The 1366 Standard does a better job than the current standard in assessing how well we perform in these two areas.

Q. What are other advantages of adopting this standard?

A. Other advantages include:

- Uniform reporting among utilities. Over 40 utilities across the country have adopted the new IEEE standard, and PacifiCorp calculates and reports SAIDI using 1366 in all States it serves other than Oregon.
- Use of an objective measure with a sound theoretical basis developed by a consortium of utilities, commissions, consultants, and academics.

Q. What other OPUC requirements are included in the SQM reports?

A. The other program results included in the SQM reports are as follows:

- Substation Safety & Equipment Condition Assessment (monthly inspection of all substations).
- Overhead switch maintenance program (all overhead line switches are inspected, maintained, repaired as necessary and operated on a 5 year cycle).
- Underground switch maintenance program (same as above but for our pad mounted switches of the underground areas of our distribution system).
- Recloser maintenance program (pole top reclosers are rotated for servicing at our shops in a 5-year cycle).
- Pole top regulator program (also removed from service as they are rotated to the shops for servicing in approximately a 5-year cycle).
- Marina inspection program (all marinas with PGE electrical facilities on the docks, primarily house boat moorages, are inspected twice a year; during high water and low water, looking for National Electric Safety Code (NESC) issues.
- Safety survey (drive by inspection program for the overhead system looking for items needing attention such as unreported storm damage, accomplished in a 2-year cycle).

- 10 underperforming feeder program (the 10 poorest performing feeders are analyzed yearly for reliability improvements to reduce outages, and work is then budgeted and completed).

Program results that are not required SQMs but are voluntarily reported include:

- Transmission full pole testing (climbing inspection to determine if decay is present in wood transmission poles put in service prior to 1980) and replacement program.
- New pole quality assurance inspection (a random sample of new poles to perform a quality assurance inspection for NESC compliance, design compliance, and PGE standards compliance (1440 poles inspected in 2009).
- Pad-mounted switch gear infrared inspection (pad mounted distribution switches are inspected for infrared hot spots on a yearly basis).

These programs are in addition to annual programs such as Tree Trimming, Locating, and FITNES that we perform annually in the Distribution area.

B. Distribution O&M Expenses

Q. Please identify the changes in Distribution O&M costs and FTEs from 2008 to 2011.

A. Distribution O&M expenses increase from approximately $69.3 million to $84.1 million, an increase of approximately $14.8 million while FTEs increase by approximately 5.

Q. If labor is not a major driver of cost increases, what are the non-labor factors that increase Distribution O&M expenses?

A. As Table 3 below shows, there are three major drivers of increased non-labor O&M expenses in Distribution: 1) approximately $7 million for restoration of service lines, 2) approximately $5.3 million for Distribution IT, and 3) approximately $1.7 million for tree

trimming costs. Other minor drivers are FITNES (approximately $400,000), and locating costs (approximately $300,000).

Table 3
Distribution Non-Labor O&M Drivers of Cost Changes
from 2008 to 2011 Test Year Forecast

Cost Driver	**$ Million**
Restore Service Lines	7.0
Distribution IT	5.3
Tree Trimming	1.7
FITNES Program	0.4
Locating Cost Increases	0.3
Total of Non-Labor Cost Drivers from 2008 to 2011	**$14.7**

We explain each of these drivers in more detail below.

1. Restore Service Lines

Q. Costs to restore service lines increase by approximately $7 million from 2008 to 2011. What is the primary reason for this increase?

A. The primary reason for the increase, approximately $4.5 million, is due to the proposal for a balancing account that would replace PGE's expiring property insurance coverage for the transmission and distribution (poles and wires) system.

Q. Doesn't PGE currently have property insurance that covers its poles and wires?

A. Yes, but we were unable to acquire replacement insurance coverage with similar terms and conditions for our T&D system. PGE Exhibit 1000 discusses the expiring T&D insurance coverage in more detail.

Q. Please describe the proposed balancing account.

A. PGE is proposing a balancing account to track the differences between what we characterize as a "Level III outage" actual costs and amounts collected in rates. The balancing account would earn interest at PGE's authorized cost of capital and would be subject to prudence review and/or audit.

Q. What is a Level III outage?

A. Level III is our most severe customer outage level. As noted in Table 4 below, PGE classifies outages into three levels, from least to most impact on our system. A Level III outage means that we, in general, expect an impact of at least 50,000 customers, or across three to four of our regions, or several substations and feeders will be out of service.

Table 4
PGE Classifications for Outages

Level I - refers to typical daily occurrences on the distribution system. These outages will increase phone calls from customers, but should not cause a hardship on call center staff. The following activities are considered Level 1 incidents:	·Two feeders out in service territory.
	·Two thousand customers or less out of service at multiple locations.
	·Restoration can be completed in less than 24 hours.
Level II – this level increases substantially the number of calls due to outages. Typically, two or less regions are involved and restoration can be completed with PGE resources. The following activities are considered Level II incidents:	·Four or more feeders or multiple tap lines out of service.
	·20 to 30 thousand customers out of service at multiple locations.
	·Restoration can be completed in 48 hours.
	·Incident may generate media attention.
Level III – at this level, many customers will be out of service. Call center will generally require support from other areas of the company to support customer calls. Management will contact other utilities for possible assistance in restoration efforts. The following activities are considered Level III incidents:	·Multiple substations and feeders out of service.
	·Greater than 50,000 customers out of service.
	·Three or four regions are experiencing outages.
	·Greater than 72 hours to restore service.
	·Outside assistance may be required.

Q. How often would the account balance be reviewed?

A. The account would be reviewed at least every two years, at which time changes could be proposed.

Q. Is there a proposed cap on the balancing account?

A. Yes. As we noted, PGE proposes to collect $4.5 million annually. We determined this amount by reviewing actual storm history and the pattern of losses over the last 15 years. Of the $4.5 million, $3.5 million would be subject to accrual in the balancing account while the remaining $1 million would be recovered in fixed O&M.

Over two years, the amount collected in the balancing account, if there were no major Level III outage events, would be $7 million. This would effectively be a cap. Also, after the second year, the balancing account would be reviewed and the cap may reset.

Q. What costs would be included in the proposed balancing account?

A. Only a Level III outage event involving our T&D system, which receives a PGE accounting job number, would be included. However, only expenses above $1 million for each Level III outage event would be placed in the balancing account.

Q. When does PGE assign a job number to a Level III outage event?

A. We assign a job number when circumstances are expected to cause a Level III outage event that impacts our T&D system.

Q. Please give an example of how the balancing account would work over a 7-year period.

A. See Table 5 below, which shows in Year 1 (2011), PGE collecting $3.5 million in the balancing account each year and experiencing multiple Level III outage events over the following 6 year period.

Table 5
Balancing Account Example

	Level III outage event Costs	Exclusion	Net Costs	Annual Collection	Balancing Account
Year 1	6.0	(1.0)	5.0	(3.5)	1.5
Year 2	2.0	(1.0)	1.0	(3.5)	(1.0)
Year 3	0.5	N/A	0.0	(3.5)	(4.5)
Year 4	0.0	N/A	0.0	(3.5)	(8.0)
Year 5	12.0	(1.0)	11.0	(3.5)	(0.5)
Year 6	5.0	(1.0)	4.0	(3.5)	0.0
Year 6 (2^{nd} storm)	2.5	(1.0)	1.5	(3.5)	(2.0)
Year 7	1.0	N/A	0.0	(3.5)	(5.5)

For purposes of this example, interest is excluded from the calculation. In addition, the example shows one Level III outage event per year. If PGE experienced multiple Level III outage events per year that impacted our T&D system, the $1.0 million exclusion would be applied on a per-Level III outage event basis.

Q. Are there alternatives other than a regulatory mechanism?

A. Yes, possibly. PGE is open to discussions with Staff and other parties on the specific characteristics of alternative mechanisms that allow for a smooth recovery on Level III outage events that impact our T&D system.

Q. What accounts for the remaining increase of $2.5 million in non-labor costs?

A. Approximately $1.7 million of the increase is due to the effect of a 2008 credit from the insurance proceeds for the large 2008/2009 winter storm. Although there were storm costs of approximately $500,000 in 2009, the entire insurance proceeds were booked to 2008. Also, the proceeds apply to all restoration costs (i.e., labor and non-labor), PGE applied the entire amount to non-labor accounts. After normalizing for the 2008 storm, non-labor restoration costs increase by approximately $800,000 from 2008 to 2011 due to higher vehicle allocations.

2. Distribution Technology Enhancements and Distribution IT

Q. What technology enhancements has PGE completed?

A. The following technology enhancements were performed to better assist our customers during outages and to more quickly resolve safety issues such as downed wires:

- The Online Outage website: Released on PortlandGeneral.com in July 2009, this website provides customer and news media access to general information about current outages within PGE's service territory. There are two main components to these new web pages: an outage map and an outage list. The outage map aggregates outage information by zip code to give an overall status of outages in a particular area. Zip codes with more than 5 customers out of power will display a pushpin, which customers can click on to view more information. Weather information is also available on the outage map page to show how weather could be impacting the current outage status. The outage list page is aggregated by county and by zip code. Clicking on a particular county on the main list page allows the user to view a list of outages in that county sorted by zip code. Information provided on the outage list page is comparable to information provided over the Interactive Voice Response (IVR) phone system today. These web pages were developed internally by Distribution Application Services.
- The Color Coded Wire Incident Application: Displays wire down outages from Outage Management System (OMS) as pushpins in Google Earth using several layers of kml files[4]. Each pushpin represents a wire incident outage at a particular transformer location. The pushpins are color-coded based on the status of the

[4] A file format used to display geographical data. When data are taken from a database (OMS in this case) they are extracted along with latitude and longitude coordinates and can be mapped in Google Earth or other types of mapping products.

outage (unassigned, assigned, emergency, resolved). Displaying the wire incident outages on Google Earth helps the wire down desk and dispatch office to respond to outages more effectively using geographic dispatching methods and allows them to spot emergency wire situations more quickly. The result is more efficient resolution of wire incident outages in major events, which enhances public safety.

- Meter Pinging: Allows repair dispatchers and line dispatchers to ping AMI meters to determine whether they are energized. The application allows the dispatchers to search for meters by feeder, transformer number, or meter number. Once located, the application allows the user to ping the meter to determine whether we have communication with the meter. If the ping request is returned as a "pass" then the meter is energized. If the ping request is returned as a "fail," then we do not have communication with the meter and further investigation is required to determine if there is an outage. This capability will enable dispatchers to trouble shoot outages more effectively. This is especially true with single customer outages that could be resolved without dispatching a crew, resulting in savings for the company.
- Automated Vehicle Locating (AVL): Implemented AVL with over 100 vehicles (mostly assigned to single-man crews). This capability allows PGE to know where these crews are located and will help us respond to potential safety issues as well as dispatch these crews more efficiently. While access to this application is extremely limited on a day-to-day basis, during storms all dispatchers will have access and will be able to dispatch and utilize these crews more efficiently.

Q. How much are Distribution IT costs increasing from 2008 to 2011?

A. We expect costs for Distribution IT to increase by approximately $5.3 million from 2008 to 2011.

Q. What are the primary reasons these costs are forecasted to increase?

A. The primary area of increase is allocated IT charges. These IT allocations consist of costs for information systems needed to support our operations; system replacement costs; increasing cyber security requirements for hardware, software and network systems; growing data storage requirements; and higher overall costs charged by vendors for maintenance agreements on PGE's systems. These costs are discussed in more detail in PGE Exhibit 600.

3. Tree Trimming

Q. How did you estimate tree trimming costs for 2011?

A. The Tree Trimming program consists of two- or three-year cycles and is contracted on a time and material basis. PGE first determines the number of crews necessary to complete the work to meet the Oregon Administrative Rule (OAR) 860-024-0016, and to complete the program descriptions contained in PGE's SQMs, and then applies the labor rates for the crews to determine total costs.

For the work in 2011, we forecast a need for 36 tree trimming bucket crews, 2 sub transmission trimming crews, 3 backlot trimming crews, 2 one-person response crews and 1 cross country right-of-way climbing/clearing crew.

Q. Comparing 2008 to 2011, are the amount of work and the number of contract crews expected to be similar?

A. Yes, we believe that they will be assuming similar weather and temperature conditions.

Q. If the amount of work and contract crews remains the same, why are tree trimming non-labor costs higher by approximately $1.7 million?

A. The increase is due primarily to the rates in the new union contract, which account for approximately $1 million of the increase. In 2009, Asplundh Tree Experts and IBEW Local 125 negotiated a new three-year contract. The negotiations lasted seven months and involved mediation. The outcome was higher wages for union employees. For PGE, which uses Asplundh, the rate for a standard two-person trimming crew increased approximately 3% per year.

The remaining amount of approximately $700,000 is related to an accounting accrual booked in 2008. The accrual, a non-budget item, is part of the year-end accounting process to properly record expense in the year that services were received. The 2008 credit amount of approximately $700,000, which is absent in 2011, indicates that the accrual amount related to December 2007 that reversed in 2008 was more than the accrual for unpaid tree trimming services that was recorded in December 2008, or in other words, we had more unpaid invoices in December of 2007 than we did in December of 2008.

Q. What is PGE doing to keep contractor costs reasonable?

A. PGE bid the tree-trimming contract in 2007, and will bid the contract again in 2010, to ensure we are receiving competitive pricing. We also manage the contract and ensure costs are reasonable and meet required specifications. PGE has a staff of seven foresters and one forester supervisor to perform this management role.

The foresters assign the work by designating trees to be trimmed or removed and they also coordinate with customers when necessary. As trimming progresses, the foresters inspect the trimming for productivity, which is determined by actual versus estimated costs, along with adherence to clearance, arboricultural, and safety specifications.

Efforts to control costs by the foresters include activities such as ensuring the contract crews are located as close to the project as possible, thereby minimizing travel time;

managing trimming debris by blowing chips back on site versus into a dump truck, thereby minimizing non-productive time spent to dump chips; requiring a project work progression plan so the crews do not have to shift job sites frequently; and requiring that the scheduling of extra resources like flagging or equipment is timely and efficient.

4. Facility Inspection and Treatment to the National Electric Safety Code (FITNES)

Q. Please describe PGE's FITNES program.

A. The FITNES program inspects, maintains, and repairs all of PGE's 280,000 poles on a 10-year cycle, and all of our underground equipment on a 4-year cycle, including PGE equipment located on large industrial campuses.

Since PGE launched the program in 1987, annual poles needing to be replaced due to decay have declined from 12% to 0.7%, saving millions of dollars in replacement costs. This is important preventive maintenance that extends equipment life, reduces costs, and increases safety. In addition, FITNES identifies potential public safety issues and resolves them before they cause outages.

Q. Why are costs increasing by approximately $400,000 between 2008 and 2011?

A. In 2008, the underground portion of the FITNES program completed the final year of the last four-year cycle, inspecting 18,200 units that year. In 2009, the current four-year cycle began. In 2011, approximately 22,000 units will be inspected if we are to maintain a four-year cycle. Over time, the number of units to be inspected will increase as residential and commercial developments add new underground facilities to our service area.

Q. Is a four-year cycle the appropriate length of time for underground inspection?

A. No. PGE has inspected its underground facilities on a 4-year cycle since 1996. Since then, we have completed multiple cycles and we believe a four-year cycle is unnecessary given the excellent condition of our underground facilities. A 10-year cycle would be more

appropriate and cost effective for our customers. We estimate that moving to a ten-year cycle would save approximately $900,000 in 2011 alone.

Q. Is a ten-year cycle supported by the OARs?

A. Yes. OAR 860-024-0011 (1) (B) (c) states the cycle length for underground facilities inspection as 10 years maximum with a recommended rate of 10% of the system per year.

Q. Do other Oregon utilities currently have a 10-year cycle?

A. Yes. Pacific Power performs underground inspections on a 10-year cycle.

5. Underground Utility Locating ("Locating")

Q. Why are costs increasing by approximately $300,000 for locating?

A. The reasons for the higher costs are due to higher contract costs, and the number of locate requests forecasted in 2011. We explain these factors in more detail below.

a. Locating Contract Costs

Q. Why are contractor costs increasing?

A. PGE's Locating contract was renewed in September 2009. As part of the negotiations, the contractor's rates increased to reflect their increased costs (according to the CPI forecast) for 2010 and 2011. This contract is bid on a unit-price basis and we have tracked the average cost per locate since 1991.

Q. How does PGE's current cost per locate compare to 1991?

A. PGE is paying less per locate today than in 1991; approximately 6% less per locate, unadjusted for inflation. When adjusted for inflation, PGE is paying approximately 41% less per locate than in 1991.

b. Locating Requests ("Locates")

Q. How does PGE forecast the number of locates for the 2011 test year?

A. PGE considers actual numbers of locates for the last three to five years to forecast the anticipated number of locates for 2011. Over the last three years (2006-2008), the average growth in locates was 6.5%. Over the last five years (2004-2008), the average growth was 6.3%. Thus, the growth has been fairly stable. We decided to use a 6% growth rate for 2010 and 2011 to reflect these historical averages.

Q. How much have locates increased from 2008 to 2009 year-to-date?

A. The number of locates is nearly flat when comparing 2008 to 2009. However, 2008 was a high year for locate requests, up 14.2% from 2007.

Q. If 2008 was a high year for locates and locates have not increased in 2009, why is PGE forecasting 6% growth for the 2011 test year?

A. PGE believes that trending the last three to five years of locates gives us the best forecast for the 2011 test year, allowing for the peaks and valleys of requests we actually receive. This method has routinely kept us within budget in the past, but may not accurately forecast growth in locates beyond 2011.

While past activity may be a reasonable indicator of future growth for programs such as Tree Trimming or FITNES (where there is a set amount of work during each cycle and growth in our system can be reasonably forecasted), that is not the case in locating. PGE is required to perform locates upon request and the amount of locating work is dependent upon the amount of requests received. There are other factors that can increase the amount of locates that historical trends cannot accurately reflect.

Q. What other factor might increase the number of locates beyond 2011?

A. Increased public awareness increases the number of locates. PGE is actively involved with local and national committees to effectively educate the public on calling 811 before digging. Local examples of increasing public awareness are: 811 billboards on I-5; training

over 800 Oregon contractors on safe digging practices; training over 3,000 Home Depot employees in Oregon stores to remind customers with digging projects to call 811 first; and the airing of Public Service Announcements (PSAs) on both TV and radio.

National examples of increasing public awareness are: partnering with corporate Home Depot to spread the Oregon pilot nationally; the partnership of Williams Pipeline and the Common Ground Alliance (CGA) to create a children's educational video, curriculum and distribution plan to begin to educate the importance of calling 811 before you dig at the elementary school level. All of these examples occurred in 2009, building on the many examples of public awareness over the years. CGA is currently working with a sponsor to display the 811 logo on their NASCAR in three different locations.

Q. What is the purpose of 811?

A. The 811 number is federally mandated to provide a single point of contact to call for digging projects anywhere in the U.S. Nationwide, there are more than 60 one-call numbers (centers that notify the various local utilities or their contractors to mark underground lines). 811 routes calls to the appropriate one call center, similar to 911 calls, eliminating the need to know the various 1-800 numbers.

The consolidated efforts and ease of the Call 811 campaign reaches millions of people through multiple media methods, as noted above, resulting in greater public safety from dig-ins and reduced damages to underground utility infrastructure.

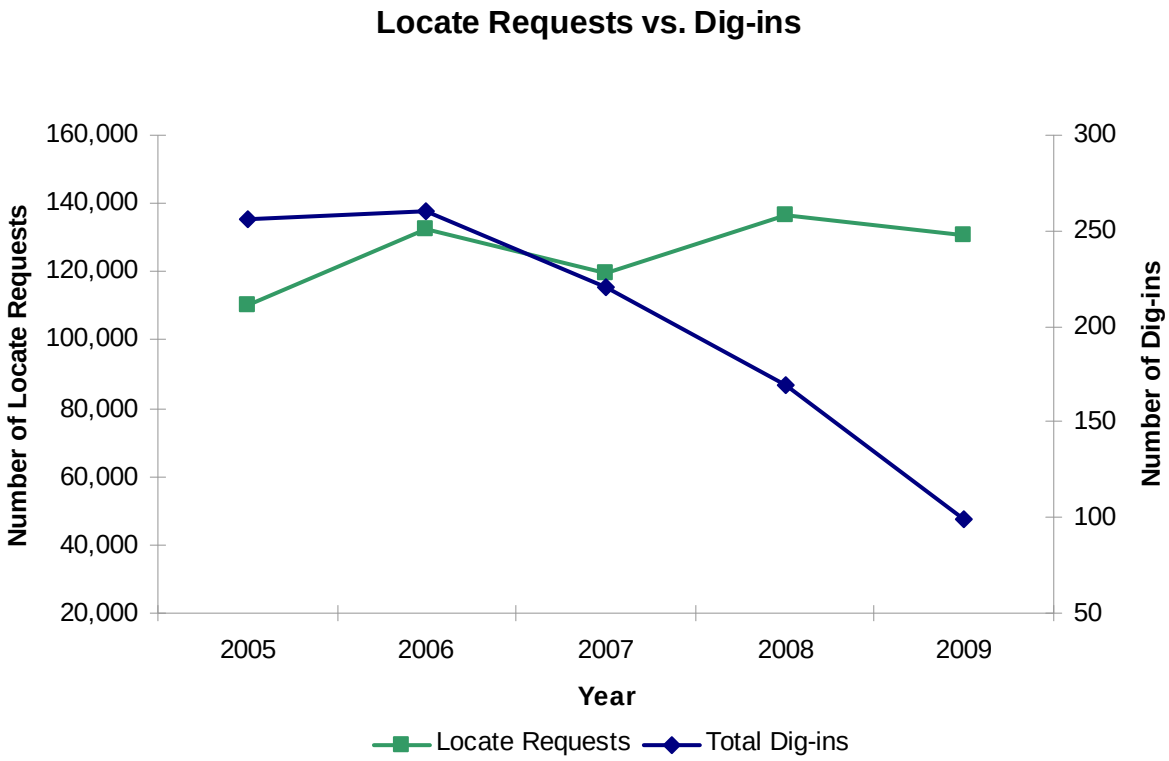
Q. Have underground utility damages decreased since the implementation of 811?

A. Yes. The 811 number went live in May 2007 and as of 2008 the estimated total number of underground utility damages occurring in the U.S. decreased to 200,000 from an estimated 456,000 in 2004, according to the latest CGA Damage Information Reporting Tool.

Q. Has PGE experienced decreased underground utility damages?

A. Yes. PGE damage incidences have decreased from 256 in 2005 to just 99 in 2009. Figure 1 below, shows the significant drop in damages to our system from 2005 to 2009.

Figure 1



The above graph shows the relationship between the number of locate requests received by Portland General Electric and the number of respective dig-in damages that were recorded from 2005 through 2009.

Q. Does PGE's 2011 test year budget reflect the decrease in the number of dig-ins?

A. No. The cost of repair is billed to the person who caused the dig-in, so while decreasing dig-ins is very important from many viewpoints, such as safety and reliability, the decrease does not impact our Distribution O&M expenses.

Q. Does PGE expect the number of locates to increase in 2011?

A. Yes, for two reasons. First, greater public awareness results in more locate requests. A survey conducted by CGA just prior to the 811 Campaign launch in 2007 concluded that only 33% of people with digging projects requiring a utility locate actually called. With

educational efforts continuing into the future, we expect to see a continuing increase in the percentage of people calling for locate requests.

Second, the economy is showing a slight recovery and should continue to strengthen through 2010 and 2011. Improved economic conditions will result in more construction activities that result in more locate requests.

IV. Qualifications

Q. Mr. Hawke, please describe your educational background and qualifications.

A. I received a Bachelor of Science Degree in Electrical Engineering and a Bachelor of Science Degree in Mathematics from Oregon State University. I received a Master of Business Administration from Portland State University. I completed additional graduate work at Portland State University in Systems Science and graduated from the Public Utilities Executive course at the University of Idaho. I am a registered professional engineer in the State of Oregon. My employment with PGE started in 1973, as an Assistant Distribution Engineer. I have held positions such as Engineering Supervisor, Chief Underground Engineer, Chief Field Engineer, Sales Manager, Regional Manager in both the Southern and Western regions, Manager of Response and Restoration, General Manager of System Planning and Engineering, and Vice President of System Planning and Engineering. In August 2004, I became Vice President of Customer Service and Delivery. I began my current position of Senior Vice President of Customer Service and Delivery in August of 2006.

Q. Mr. Nicholson, please describe your educational background and qualifications.

A. I received a Bachelor of Science Degree in Nuclear Engineering from Oregon State University. I completed the Harvard University Program on Negotiation and graduated from the Public Utilities Executive course at the University of Idaho. I am a registered professional engineer in the State of Oregon and I belong to the American Society of Mechanical Engineers and the National Society of Professional Engineers. My employment with PGE started in 1980 as an engineer at the Trojan Plant and I have served in a variety of capacities in Distribution Operations, Generation Engineering and Resource Development.

In May 2007, I became Vice President of Customers & Economic Development, before assuming my current role as Vice President of Distribution in August of 2009.

Q. Does this conclude your testimony?

A. Yes.