

**Table of Contents**

- I. Introduction..... 1**
- II. Resource Summary ..... 3**
  - A. Power Supply Resources..... 3
  - B. Transmission Resources..... 6
- III. Plant and Power Operations O&M and Capital Additions ..... 9**
  - A. Plant O&M..... 9
  - B. FTE Changes..... 22
  - C. Capital Expenditures ..... 23
  - D. Environmental Services ..... 29
- IV. Cost Efficiency in Generation ..... 43**
- V. Hydro Relicensing Update and Related Revenue Requirement..... 47**
- VI. Qualifications..... 49**
- List of Exhibits ..... 50**

## I. Introduction

1 **Q. Please state your names and positions with PGE.**

2 A. My name is Stephen Quennoz. My position at PGE is Vice President, Power Supply. I am  
3 responsible for all aspects of PGE's power supply generation and for decommissioning the  
4 Trojan nuclear plant.

5 My name is Arya Behbehani. I am the Manager of Environmental Services at PGE. I  
6 am responsible for compliance with environmental regulations as it pertains to generation  
7 and distribution of electricity.

8 Our qualifications are provided in Section VI.

9 **Q. What is the purpose of your testimony?**

10 A. The purpose of our testimony is to support Operations and Maintenance Costs (O&M) and  
11 rate base related costs associated with PGE's long-term power supply resources, both owned  
12 plants and contracts. We also update relicensing information regarding our hydro facilities.

13 **Q. What is the primary goal of PGE's plant related activities?**

14 A. The primary goal of our plant related activities is to maintain high levels of plant availability  
15 and system reliability as the composition of our production resource mix evolves over time.  
16 High availability allows our power operations group to dispatch plants whenever their  
17 variable costs are less than the market price of power, thereby keeping net variable power  
18 costs low. High system reliability ensures that we meet our obligation to serve on-demand  
19 customer loads.

20 **Q. Does your testimony explain how you are achieving this primary goal?**

21 A. Yes. In Section III-A, we discuss activities that maintain the reliability of our power plants.  
22 For example, when longer planned maintenance outages are necessary, we schedule them at  
23 times of the year when power prices are forecast to be low. Continued good plant

1 availability directly influences the test year net variable power cost forecast presented in  
2 PGE Exhibit 400, and thus directly benefits our customers.

3 **Q. How do you organize your testimony?**

4 A. We organize our testimony into the following sections:

- 5 • Section I: Introduction
- 6 • Section II: Resource Summary (Plants, Power Contracts, and Transmission)
- 7 • Section III: Plant and Power Operations (O&M, FTEs, Capital Additions, and  
8 Environmental Services)
- 9 • Section IV: Cost Efficiencies
- 10 • Section V: Hydro Relicensing Update
- 11 • Section VI: Qualifications

## II. Resource Summary

### A. Power Supply Resources

1 **Q. Have you prepared an exhibit that shows all of PGE’s power supply resources for the**  
2 **2011 test year?**

3 A. Yes. PGE Exhibit 701 lists PGE’s supply resources, their capacity, and their expected  
4 energy output.

5 **Q. Have PGE’s long-term power supply resources changed significantly since the UE 197**  
6 **and UE 209 (RAC) proceedings?**

7 A. The only significant change is the addition of the third phase of our wind resource, Biglow  
8 Canyon; we discuss Biglow Canyon phase 3 O&M in Section III-A, 3. PGE Exhibit 300  
9 discusses the overall plant. In addition to Biglow, we have expanded our dispatchable  
10 standby generation (DSG) capacity.

11 **Q. How large is PGE’s DSG capacity?**

12 A. As of January 2010, we have 23 dispatchable standby generation sites (containing 37  
13 generators) completed that can provide 48.0 MW of reliable diesel-fired capacity at peak  
14 times. By December 2010, we will have added at least 8 new sites, for a total of 31 sites (56  
15 generators) and 75.2 MW. This is a substantial increase from the end of 2007, when we had  
16 completed only 19 sites with a combined capacity of 39.0 MW.

17 **Q. Does PGE plan to add DSG capacity in the future?**

18 A. Yes. PGE is targeting an additional 15 MW of dispatchable standby capacity annually for  
19 the next 5 years. DSG projects have reduced operating costs compared to larger capacity  
20 projects of 20 MW or more. The focus on expanding DSG capacity allows PGE to obtain  
21 necessary capacity at reduced costs in today’s difficult economy.

1 **Q. Besides peak-load capacity, are there other benefits that the dispatchable standby**  
2 **generators provide?**

3 A. Yes. Because PGE can start these resources within ten seconds, they provide a block of  
4 reserve power for our system. In 2011, PGE may be required to maintain reserves equal to  
5 3% of generation and 3% of total load; of the total 6%, half must be spinning. Dispatchable  
6 standby generators do not qualify as spinning reserves, but they can help provide the  
7 remaining operating reserves – 1.5% for generation and 1.5% for total load. Thus, the  
8 existing 48.0 MW of dispatchable standby generation can provide non-spinning reserves for  
9 almost 3,200 MW of generation or total load.

10 In addition to providing non-spinning reserves, dispatchable standby generation, when  
11 operating, acts like a demand response program – it supplies most or all of dispatchable  
12 standby generation customers’ loads, effectively removing these loads from the grid.  
13 Finally, dispatchable standby generation adds some fuel diversity to PGE’s resource mix.

14 **Q. Is PGE’s need for capacity resources growing?**

15 A. Yes. As discussed in our Integrated Resource Plan (IRP) (Docket No. LC 48), PGE  
16 traditionally has had greater energy than capacity needs. With reduced access to hydro,  
17 increased reliance on wind generation, and growth in summer peaking loads, PGE’s capacity  
18 needs now exceed our energy needs.

19 **Q. Why does PGE need flexible capacity resources?**

20 A. Capacity resources have a dual purpose. First, they enable a utility to meet its obligation to  
21 provide safe and reliable power to customers during peak demand periods. Specifically,  
22 these resources help meet customer loads, sometimes under conditions which may be  
23 extreme, but of short duration during the year. For example, we might have an immediate  
24 need for power if one of our major thermal resources suddenly “trips” (shuts down or “goes

1 off-line”) or if loads increase rapidly due to an extreme temperature event. Second, capacity  
2 resources allow for the integration of intermittent renewable resources. Our increased level  
3 of intermittent resources, required to meet the Oregon Renewable Portfolio Standard,  
4 necessitates that we maintain flexibility and load following capability in our generation  
5 portfolio.

6 **Q. What criteria does PGE use in its selection of capacity resources?**

7 A. We consider two primary criteria. The first and most important is that the resource must be  
8 reliably dispatchable on demand. The second most important criterion is low fixed costs for  
9 customers. Possible margins on wholesale energy are not a driving consideration because  
10 capacity resources generally have high variable costs, making them uneconomical to run  
11 except in extreme events.

12 **Q. Do capacity resources selected by PGE have to compete with other capacity**  
13 **alternatives?**

14 A. Yes. These capacity resources must compete against other capacity-like resources. Large  
15 capacity projects (those which have durations greater than 5 years and are larger than 100  
16 MW) must participate and be selected through a specific Request for Proposal process using  
17 an independent observer, as called for by OPUC guidelines.

18 **Q. Does PGE have plans for major new power supply resources in the future?**

19 A. Yes. PGE’s latest IRP was filed on November 5, 2009. The plan includes additional base-  
20 load plant resources such as a combined cycle combustion turbine and up to 200 MW of  
21 flexible peaking capacity generation. However, none of the costs of these potential future  
22 projects are included in the 2011 test year.

**B. Transmission Resources**

1 **Q. Why does PGE require long-term transmission contracts?**

2 A. PGE is a transmission dependent utility. That is, we do not have enough PGE-owned  
3 transmission to move our generated/purchased energy to our system. Therefore, we must  
4 purchase adequate transmission capacity from third-party providers or build transmission to  
5 reliably and cost-effectively meet our customer load obligations. Our transmission  
6 dependence stems from our need to transmit energy from remote generating resources,  
7 long-term contractual delivery points, and short-term markets to meet our customers' needs.  
8 Even with efficient new resources such as Port Westward, PGE can sometimes lower costs  
9 for customers by purchasing energy on the wholesale market and then arranging to deliver  
10 that energy to our service territory.

11 **Q. What major transmission agreements does PGE have with Bonneville Power  
12 Administration (BPA)?**

13 A. PGE has three major transmission agreements with BPA. These are:

- 14 • Point-to-Point (PTP) agreements,
- 15 • AC/DC Intertie agreement (also involves PGE Transmission Services), and
- 16 • Montana Intertie agreement.

17 **Q. Please describe the PTP agreements.**

18 A. The PTP agreements provide PGE with firm transmission rights across BPA's transmission  
19 system from one point of receipt (POR) to one point of delivery (POD). This transmission  
20 can also be redirected firm (when transfer capacity is available) and non-firm from  
21 alternative PORs to alternative PODs. These agreements include eleven PTP service  
22 agreements resulting from the conversion of PGE's legacy Integration of Resources (IR)

1 agreement, which expired on December 31, 2009. PGE Exhibit 702 summarizes all of  
2 PGE’s PTP agreements.

3 **Q. Please describe the IR agreement conversion.**

4 A. PGE’s IR agreement with BPA allowed PGE to deliver 2,218 MWs of power from our  
5 thermal resources, the Mid-Columbia hydros, and a system (capacity) purchase from  
6 Spokane Energy to the PGE system and to the head of the Intertie. A renewal of the IR  
7 agreement was not possible. Therefore, PGE negotiated to replace the IR contract with  
8 eleven PTP agreements, which continue to provide PGE access to transmission for the same  
9 purposes in a more flexible manner at no additional cost.

10 **Q. Please describe the AC/DC Intertie Agreement.**

11 A. PGE’s AC/DC Intertie rights are defined in the BPA/PGE Intertie Agreement, which is in  
12 effect as long as the facilities of the Joint AC Intertie are operable. Under this agreement,  
13 PGE Transmission Services (PGE Transmission) controls 850 MW<sup>1</sup> of southbound rights on  
14 the AC line from John Day to the California-Oregon border. PGE’s power operations<sup>2</sup>  
15 group has purchased 200 MW of rights on the southbound AC line that it uses to sell excess  
16 power to California. This 200 MW purchase was made pursuant to PGE Transmission’s  
17 open access tariff. The power operations group also has rights to 100 MW of DC Intertie  
18 pursuant to an exchange of AC for DC (resulting in a decrease in AC rights from 950 MW  
19 to 850 MW) under the BPA/PGE Intertie Agreement.

20 **Q. Please describe the Montana Intertie agreement.**

21 A. This agreement represents an exchange of firm transmission rights between PGE and BPA  
22 that enables PGE to transmit energy from our share of Colstrip Units 3 and 4 to BPA’s

---

<sup>1</sup> PGE controls 850 MW of the AC Intertie under the Intertie Agreement. The 850 MW includes 75 MW owned by Bank of America Leasing. An additional 13 MW of transmission capacity is provided (for a fee) to Bank of America Leasing to permit them to transmit 88 MW of power to San Diego Gas & Electric.

<sup>2</sup> PGE’s power operations group is also called “PGE Merchant” to distinguish it from PGE Transmission under FERC’s open access policies.

1 system at Garrison, located in Western Montana. PGE then uses BPA PTP (Garrison to  
2 PGE’s system) to move the power to our service territory. The Montana Intertie agreement  
3 provides PGE with 280 MW of firm transmission on BPA’s line from Townsend to Garrison  
4 in exchange for BPA rights of firm transmission on the Colstrip line from Townsend to  
5 Broadview, which is located approximately midway between Townsend and Garrison.

6 **Q. Do you discuss the O&M expenses and capital additions associated with PGE’s owned**  
7 **transmission resources?**

8 A. No. Mr. Hawke discusses these transmission requirements in his testimony, PGE Exhibit  
9 800.

### III. Plant and Power Operations O&M and Capital Additions

#### A. Plant O&M

1 **Q. Please summarize PGE’s plant and power operations related O&M costs from 2008 to**  
2 **the 2011 test year.**

3 A. Table 1 below provides plant O&M costs from 2008 to 2011.

**Table 1**  
**Summary Plant-Related O&M Statistics (\$millions)**

	<b>2008</b>	<b>2011</b>
	<b>Actuals</b>	<b>Test Year</b>
Coal O&M <sup>(1)</sup>	31.8	41.1
Gas O&M <sup>(2)</sup>	23.9	28.7
Wind O&M	4.0	11.8
Hydro O&M	11.0	19.4
General Plant O&M	4.7	3.5
Power Operations O&M	13.3	14.1
<b>Totals*</b>	<b>88.7</b>	<b>118.6</b>

*\* Does not include Solar or Nuclear*

*(1) Adjusted for a reduction to the Boardman budget*

*(2) Adjusted for the Coyote Springs LTSA and FTEs*

4 **Q. What are the primary drivers for the changes in O&M in Table 1?**

5 A. There are several primary drivers, including:

- 6 • \$3.2 million increase for the planned maintenance outage scheduled at Colstrip in  
7 2011, to overhaul Unit 3 and perform additional maintenance on Unit 4.
- 8 • \$2.6 million increase for costs related to the disposal of fly ash at Boardman.
- 9 • \$2.5 million increase related to changes in the IT allocation, including a new  
10 allocation for Port Westward. The increase in IT allocations is discussed in more  
11 detail in PGE Exhibit 600.
- 12 • \$1.5 million increase for materials that are related to the Coyote Springs major  
13 maintenance planned outage in 2011, but are outside the scope of the Long Term  
14 Service Agreement (LTSA).

- 1       • \$6.3 million increase in the Biglow Service Agreements related to the additions of  
2       Biglow Canyon 2 and 3.
- 3       • \$1.7 million increase related to increases in existing State, USGS, and FERC land  
4       fees at various hydro sites.
- 5       • \$2.0 million increase for the required lead abatement clean-up at Oak Grove in  
6       2011.
- 7       • \$3.0 million increase related to an increase in labor costs at the hydro sites,  
8       primarily for environmental services, licensing requirements, and new park  
9       maintenance responsibilities.
- 10      • \$0.3 million increase in Dispatchable Standby Generation to cover maintenance  
11      related to increasing MW capacity.

12           We provide detailed explanations of plant and power operations O&M cost changes  
13      below.

***1. Coal Plant O&M***

14      **Q. Please discuss the changes in coal plant O&M expenditures shown in Table 1 above.**

15      A. The 2011 coal plant budget is approximately \$9.3 million higher than 2008, primarily due  
16      to:

- 17      • Colstrip costs increase approximately \$4.6 million from 2008 to 2011. The  
18      primary driver is a major maintenance overhaul planned for Unit 3 in 2011, which  
19      results in an increase of \$3.2 million for outside services and material. This  
20      51-day outage includes the 44-day outage work and an additional 7-day chemical  
21      clean of the boiler. There was no major maintenance work in 2008. The  
22      remaining \$1.0 million is escalation, increased taxes and labor, cleaning of the

1 boiler and HP turbine, offset by classification of costs for lime chemicals to Net  
2 Variable Power Costs (Exhibit 400).

- 3 • Boardman costs increase by \$4.7 million from 2008 to 2011. There are new  
4 disposal costs estimated at \$2.6 million for fly ash, an increase in the IT service  
5 provider allocation of \$0.7 million, an increase in labor (including work related to  
6 the 2011 outage) of \$0.4 million, and approximately \$1.0 million related to  
7 materials for the storeroom and maintenance work, as well as miscellaneous items  
8 such as oil and lubricants for pumps and valves.

9 **Q. Please explain the disposal costs for fly ash at Boardman.**

10 A. Fly ash is a byproduct of coal combustion. PGE currently sells the ash to vendors, where it  
11 is used as an additive to cement and other beneficial uses. However, pending U.S.  
12 Environmental Protection Agency (EPA) regulations may classify fly ash as hazardous  
13 material. If Boardman’s fly ash is classified as hazardous, PGE will be forced to dispose of  
14 the material by shipping it to a hazardous waste disposal site; the nearest is located in  
15 Arlington, Oregon. The estimated total cost for disposal of hazardous material is  
16 approximately \$15.0 million. For 2011, we have budgeted \$4.0 million for these costs, \$2.6  
17 million of which is PGE’s share. This \$4.0 million estimate is from 2009, before current  
18 information was available. This estimate will be re-evaluated should the EPA classify any  
19 form of fly ash to be hazardous. (Note: a decision is expected in the first half of 2010).

20 **Q. Is fly ash also an issue at Colstrip?**

21 A. Yes. Boardman produces a “dry” fly ash, while the ash at Colstrip is classified as “wet” fly  
22 ash. The EPA is evaluating both dry and wet fly ash as a possible hazardous material.

23 **Q. If the wet ash at Colstrip is considered hazardous, are there potential costs?**

1 A. Yes. The potential costs have not yet been incorporated into the Colstrip budget and, thus,  
2 are not yet included in the test year. Should the EPA rule that wet fly ash is a hazardous  
3 material, Colstrip could choose to dispose of the wet ash, or they could modify their systems  
4 to produce dry ash instead of wet ash.

5 **Q. Please explain the challenges of employee turnover at Boardman.**

6 A. Boardman has experienced higher turnover in the past several years, which creates  
7 significant challenges to keep the plant staffed with experienced and fully trained  
8 employees. The turnover is a result of three things: 1) employee concern about the future of  
9 the Boardman plant, 2) a different union agreement at Coyote, which is favored by many  
10 employees and has resulted in transfers from Boardman to Coyote, and 3) many employees  
11 at Boardman are at or near retirement.

12 These vacancies result in higher overtime for employees and additional training to get  
13 new employees fully qualified. It takes 2,000 training hours, or approximately 18 months,  
14 for the average employee to become fully trained. These factors result in increased labor  
15 costs.

16 **Q. Please explain the maintenance cycles at Boardman.**

17 A. Boardman has a planned outage every spring. An overhaul of each of the three turbine units  
18 and generator is required every 10 years, resulting in a major extended outage approximately  
19 every 5 years. The outages for these major plant components are typically 6 weeks long.  
20 The outage duration in other years is typically 4 weeks, and consists of routine repairs to  
21 plant components (e.g., the boiler) that require the unit to be offline.

22 **Q. Please describe the work to be completed in the 2011 outage at Boardman.**

23 A. 2011 is considered a major outage year because the plant will install new low NOx burners,  
24 mercury controls and overfire air ports, replace one third of the boiler convection pass

1 reheater, and install a combustion monitoring system and new boiler cleaning equipment.

2 This work will all be capital work and the outage is expected to last 6 weeks. Major non-  
3 capital work that is scheduled to be completed includes the following: rebuild of  
4 superheat/reheat temperature control dampers, overhaul of the throttle and governor valves,  
5 replacement of a main feed pump volute, inspections of hot reheat elbows, inspections of  
6 snubbers for large diameter critical piping, and an air preheater high pressure wash.

7 Additionally, maintenance will be performed on coal handling equipment<sup>3</sup>.

## 2. Gas Plant O&M

### 8 **Q. Please discuss the changes in gas plant O&M expenditures shown in Table 1 above.**

9 A. Costs for our primary gas plants – Beaver, Port Westward, and Coyote Springs – increase by  
10 about \$4.8 million from 2008 to 2011.

- 11 • Costs at Beaver decrease by approximately \$45,000 from 2008 to 2011.

12 Preventative Maintenance costs decrease by almost \$500,000 in 2011 related to  
13 repairs to the Unit 7 generator rotor in 2008, and further decrease by almost  
14 \$100,000 due to CT generator inspections in 2008. However, these decreases are  
15 offset by increases in IT Services of \$200,000, and materials, outside vendor  
16 services, and labor, which increase by \$200,000. Finally, Personal Protective  
17 Equipment costs increase by \$100,000 and Clatskanie PUD site electrical and  
18 emergency station service supply, oil spill cleanup, and emergency costs, not  
19 required in 2008, increase expenses by \$50,000.

- 20 • Port Westward costs increase by \$1.9 million from 2008 to 2011. \$0.95 million  
21 of the total increase is from the IT Service Provider Allocation – 2010 is the first  
22 year that Port Westward is included in the allocation. \$300,000 is related to the

---

<sup>3</sup> Maintenance on coal handling equipment will consist of work on the coal dumper and one of the stacker reclaimers.

1 repair of the KB Pipeline, and the LTSA account increases by over \$200,000 as  
2 more maintenance is required when the plant is running longer.

- 3 • Coyote Springs costs increase by \$2.8 million in 2011. \$1.5 million is related to  
4 materials and parts for the 2011 maintenance activities, and \$500,000 is related to  
5 contractors for major maintenance activities outside the GE scope. In corrective  
6 maintenance, work to replace the exhaust joints for the Heat Recovery Steam  
7 Generator (HRSG) increases costs by \$300,000 and combustion inspection labor  
8 increases costs by \$200,000. The remaining \$300,000 increase is due to increases  
9 in the IT Service Provider allocation.

10 **Q. PGE has plans to upgrade the turbine at Coyote Springs I during the 2011 outage. If**  
11 **this occurs, will any O&M costs be reduced?**

12 A. Yes. The upgrade itself is discussed in Sections III-C and IV below. If the turbine upgrade  
13 is implemented, the \$0.3 million expansion joint replacement for the HRSG will not be  
14 necessary.

15 **Q. Please explain the Coyote Springs LTSA.**

16 A. PGE has an LTSA with General Electric (GE) for maintenance of the 7F turbines at the  
17 Coyote Springs plant. LTSA pricing is based on a fixed cost per quarter (escalated yearly)  
18 and a variable cost based on gas turbine hours of operation (“factored hours”, adjusted for  
19 mode of plant operation). This pricing method results in O&M costs that vary considerably  
20 from year to year.

21 **Q. Is there a mechanism in place to smooth Coyote Springs annual maintenance costs?**

22 A. Yes. PGE established an amortization mechanism in UE 93 that was last updated in  
23 UE 180. This mechanism covers major maintenance events at the Coyote Springs plant. The

1 update in UE 180 resulted in an amortization schedule that will not be updated for the 2011  
2 test year. The amortization amount for the 2011 test year is \$2.04 million.

3 **Q. What maintenance costs will Coyote Springs incur under the LTSA in 2011?**

4 A. In 2011, Coyote Springs is forecast to operate 6,400 factored hours, resulting in a variable  
5 LTSA fee of \$4.75 million. In addition, the unit will have operated for 48,000 hours since its  
6 last major inspection, at which point the unit's second major inspection (since the original  
7 installation of the gas turbine, steam turbine, and generator) is required. This major  
8 inspection will result in unusual access to plant components and a scheduled outage of  
9 significant duration. This enhanced access is required to perform advanced inspections,  
10 along with related work including combustion turbine alignment, exhaust frame  
11 modifications, repairs to thrust bearings, the generator stator and the generator field. The  
12 cost of these inspections and repairs (approximately \$2.0 million) plus the variable LTSA  
13 fee, lead to an LTSA amount of \$6.8 million for 2011.

14 **Q. Is the \$6.8 million included in the 2011 test year?**

15 A. No. Instead, we include a levelized \$2.04 million in the test year revenue requirement and  
16 reverse the \$6.8 million O&M amount in amortization expense. This effectively substitutes  
17 the levelized \$2.04 million annual collection amount for the \$6.8 million O&M amount,  
18 thereby reducing the revenue requirement by \$4.7 million. Table 1 reflects the \$2.04 million  
19 figure for each year.

20 **Q. Is all the 2011 maintenance work at Coyote Springs covered under the LTSA?**

21 A. No. The LTSA at Coyote Springs covers a scope of work previously negotiated with GE.  
22 The scope includes work generally related to the combustion turbine and other major parts,  
23 such as inspections of the steam turbine or combustion parts on the main unit. The  
24 additional 2011 expenses are for jobs that fall outside of the LTSA scope, such as cleaning

1 and coating the selective catalytic reduction plates with new catalyst, battery replacement,  
2 lube oil and resin replacements, re-engineering of the make-up water demineralizer, and  
3 rebuilding cooling tower gear box fan wheels.

4 **Q. Is PGE planning to update the LTSA?**

5 A. Yes. PGE is negotiating an update to the LTSA with GE that will coincide with the plant  
6 upgrade in 2011.

7 **Q. What types of maintenance will the new agreement cover?**

8 A. We expect the new LTSA to cover parts, inspections, and maintenance for the gas and steam  
9 turbines. Under the preliminary agreement, planned maintenance and unplanned prepaid  
10 maintenance will be performed at pre-agreed prices, helping to insulate PGE from rising  
11 prices. The agreement will provide for discounts for extra work, include incentives and  
12 liquidated damages provisions tied to availability, and require GE to provide both on-site  
13 and remote analytical and technical support.

14 **Q. Will there be new provisions in the updated LTSA?**

15 A. Yes. We expect the updated LTSA to have improved coverage of unplanned maintenance  
16 costs and collateral damage costs. It is expected to provide increased discounted rates for  
17 parts and services for extra work, liquidated damages for parts delivery, coverage for  
18 Technical Information Letters, price surety over the life of the contract and on-site, remote  
19 monitoring and diagnostics by GE and on site GE representation. We also anticipate re-  
20 negotiated payment terms that should result in a smoother year-to-year payment schedule.

21 **Q. What do you expect the payment terms to be under the new agreement?**

22 A. We expect that the amended and restated LTSA will cover the last two payment periods of  
23 the original LTSA. As a result, the pricing for those periods should remain unchanged from  
24 the original agreement. Beginning in the fourth quarter of 2011 (according to the

1 preliminary agreement), the pricing will adjust to \$511 per factored hour (in 2010 dollars,  
2 escalated using the same indices currently used in the original LTSA). After the transition  
3 to the new pricing method, the large annual swings in maintenance charges that  
4 characterized the original LTSA should be eliminated. Annual price changes should result  
5 only from the escalation provisions in the contract, which we anticipate to be the same  
6 as those in the original contract.

### ***3. Wind Generation O&M***

7 **Q. Please explain the changes in wind O&M expenditures shown in Table 1.**

8 A. The increase in wind O&M from 2008 to 2011 is approximately \$7.8 million. Most of this  
9 increase can be attributed to the full-time operation of all three phases of the Biglow Canyon  
10 Wind Farm in 2011 compared to first-phase-only operation in 2008.

11 **Q. What are the major drivers of the increase in Biglow O&M expenses?**

12 A. There are four major drivers of the increased O&M expenses:

- 13 • Biglow Service Agreements for Biglow Canyon phases 2 and 3, plus escalation of  
14 the Biglow Canyon phase 1 agreement: \$6.3 million
- 15 • Operations (primarily additional “station service” load for Biglow Canyon phases  
16 2 and 3): \$0.6 million
- 17 • Environmental Services (compliance with all aspects of Federal and State  
18 requirements including wildlife monitoring): \$0.2 million
- 19 • Increased staffing (4 FTEs) for the two additional phases: \$0.2 million

### ***4. Hydro Plant O&M***

20 **Q. What are the major components of the changes in hydro O&M expenditures shown in**  
21 **Table 2?**

1 A. The increase in hydro O&M from 2008 to 2011 is approximately \$8.4 million. Of this  
2 amount, approximately \$1.7 million is due to increased environmental services  
3 requirements. While we mention these costs in this section, they are more fully explored in  
4 Section III-D below.

5 Table 2 below breaks out hydro O&M between labor and non-labor expenses. The  
6 increase in non-labor hydro O&M from 2008 to 2011 is approximately \$5.6 million while  
7 the increase in labor costs is approximately \$2.8 million.

**Table 2**  
**Hydro Expenses (\$ Millions)**

	<b>2008</b>	<b>2011</b>
	<b>Actuals</b>	<b>Test Year</b>
Hydro O&M Expenses	\$11.0	\$19.4
Hydro Non-Labor O&M Expenses	6.0	11.6
Hydro Labor Expenses	4.9	7.8
<b>Total Hydro Expenses</b>	<b>21.9</b>	<b>38.8</b>

8 **Q. Please explain the increase in non-labor hydro O&M expenditures shown in Table 2**  
9 **above.**

10 A. Most increases in hydro O&M fall into three general categories: hydro licensing  
11 requirements (including increases in fees), environmental services, and on-going  
12 maintenance projects for the preservation of facilities. We discuss these increases by hydro  
13 system, i.e., westside, and eastside projects.

**Westside Hydroelectric Project**

14 Four facilities are governed by the new Clackamas River Hydroelectric Project  
15 (Clackamas) License: North Fork, Faraday, River Mill Dam, and Oak Grove. The new  
16 license establishes operational and other requirements for these facilities that were not in  
17 effect in 2008. One of these requirements is participation of the Clackamas River Fish  
18 Committee in operational decisions. The Fish Committee is one of the implementation  
19 committees for the new Clackamas license. The Fish Committee includes natural resource

1 agencies, tribes, and representatives from environmental organizations. The Fish Committee  
2 is involved in the implementation of all fish passage, fish protection, and aquatic measures  
3 during the term of the new license.

4 O&M expenses at River Mill for 2011 are essentially unchanged from 2008. The  
5 drivers of cost increases for the other projects are summarized below.

- 6 • Faraday - At the Faraday facility, a \$0.7 million increase is due to several factors,  
7 including \$0.4 million to meet new license requirements. Clackamas River Fish  
8 Committee support accounts for most of the \$0.4 million required to meet license  
9 requirements. A \$0.1 million increase is due to an increase in the IT allocation to  
10 Faraday. IT allocations are discussed in detail in PGE Exhibit 600.
- 11 • North Fork - The \$0.3 million increase includes approximately \$200,000 in  
12 incremental maintenance expenses (including \$100,000 to dredge the marina area  
13 of the reservoir and \$88,000 for work on the Migrant Fish Pipe) and \$80,000 that  
14 represents a portion of the FERC land fee increase.
- 15 • Oak Grove - The \$3.7 million increase includes \$0.4 million to meet license  
16 requirements, \$2.1 million to meet maintenance requirements, \$0.3 million for  
17 environmental services, and \$1.2 million for increases in rental payments and  
18 fees. The \$0.4 million to meet license requirements is made up primarily of costs  
19 necessary to fulfill new hydro license commitments for protection, mitigation, and  
20 enhancement measures at Timothy Lake. The \$2.1 million to meet maintenance  
21 requirements is composed of lead abatement measures (\$2.0 million) and painting  
22 projects. The lead abatement project and painting projects are discussed further in  
23 Section III-D. The environmental services cost increases are fee increases of  
24 \$177,000 and professional services cost increases of \$150,000. Environmental

1 services costs at Oak Grove are also discussed in Section III-D. The \$1.2 million  
2 increase in rental payments and fees is a portion of the FERC land fee increase.

**Eastside Hydroelectric Projects**

3 PGE's eastside hydroelectric projects are Round Butte and Pelton. PGE has a two-  
4 thirds ownership share in these plants. At Round Butte, a \$0.8 million increase in O&M  
5 expenses includes \$0.1 million for a runner repair and \$0.04 million for improved IT data  
6 and voice services. The remainder of the increase is located primarily in Environmental  
7 Services and is discussed in Section III-D. 2011 O&M expenses at Pelton are essentially  
8 unchanged from 2008.

**Hydro Labor Expenses**

9 **Q. Please explain the changes in hydro labor costs shown in Table 2.**

10 A. Increases in environmental services costs and hydro licensing requirements account for a  
11 large proportion of the increase in labor expenses. The environmental service requirements  
12 are discussed in Section III-D. Under the new Clackamas license requirements, PGE will  
13 now be responsible for the maintenance of the campground previously administered by the  
14 Forest Service. This increases PGE labor for Timothy Lake including seasonal and  
15 recurring labor, oversight of general maintenance, reservations systems, and supervision of  
16 PGE seasonal labor.

***5. General Plant O&M***

17 **Q. What are the primary reasons for the cost increases in the general plant?**

18 A. Although O&M decreases overall, there are two large increases in this area:  
19 • Preventative maintenance for (DSG) increased by \$300,000 from 2008 to 2011,  
20 primarily due to addition of more sites and capacity. As discussed earlier, PGE is  
21 targeting an additional 15 MW of DSG per year for the next five years. To help

1 mitigate this increase, PGE groups maintenance work together and carefully  
2 evaluates bids from several outside maintenance companies. Additional DSG  
3 related O&M expenses are included in PGE Exhibit 900, Section V.

- 4 • The Portland Harbor Superfund costs increase by approximately \$700,000  
5 primarily related to increases in Professional Services to support PGE’s interests  
6 and fees for the Natural Resource Damage Assessment (NRDA) and the  
7 Convening/Allocation process. The purpose of the NRDA is to perform studies to  
8 assess damage to natural resources arising from contamination in Portland  
9 Harbor. The Convening process involves potentially responsible parties to  
10 develop a damages assessment plan and assigns responsibilities to those  
11 potentially responsible parties.

***6. Power Operations O&M***

12 **Q. Power Operations O&M expenditures increase by approximately \$0.8 million from**  
13 **2008 to 2011. What accounts for this increase?**

14 A. Non-labor O&M expenses are essentially unchanged from 2008 to 2011. The increase in  
15 labor expense is the result of wage escalation and the addition of four FTEs, two of which  
16 are transfers from the Transmission & Reliability Services (T&RS) group and two new FTE  
17 positions.

**B. FTE Changes**

1 **Q. What is the increase in FTEs for plant and power operations?**

2 A. The net increase is approximately 20.

3 **Q. Please summarize the plant and power operations FTE changes from 2008 to 2011.**

4 A. From 2008 to 2011, total FTEs in plant and power operations increase based on new  
5 operational needs. As the last of the three phases of the Biglow Canyon Wind Farm  
6 becomes operational in late 2010, additional wind technicians will be needed to support the  
7 increased generation. The Generation Projects department needs additional specialists to  
8 develop and implement project controls related to Biglow Canyon phase 3, Port Westward,  
9 and Boardman environmental controls. As we increase our DSG sites, we need to add  
10 management and technical support to handle the increasing workload. Park attendants are  
11 necessary at Timothy Lake since PGE will assume maintenance responsibility for the  
12 recreation site per the requirements of the FERC license for Clackamas.

13 The Power Supply Engineering Services group, which works on engineering projects at  
14 all of our generation sites, requires additional employees to ensure that all labor, work plans,  
15 materials, vendors, and project schedules are organized and used efficiently and to focus on  
16 wind energy, renewable energy, substation design, protection engineering, and continuous  
17 emissions monitoring. PGE will require additional support related to environmental services  
18 and environmental compliance requirements, including: Selective Water Withdrawal fish  
19 facility operations, Biglow Wind Farm wildlife and oil spill monitoring, Pelton Round Butte  
20 protection mitigation enhancement, the sockeye salmon reintroduction plan, fisheries &  
21 aquatic programs, and Oregon Department of Environmental Quality (Oregon DEQ)  
22 compliance requirements.

### C. Capital Expenditures

1 **Q. Please summarize plant related capital expenditures from 2009 to the 2011 test year.**

2 A. Table 3 below summarizes these capital expenditures for 2009, 2010, and 2011. Additional  
3 information regarding the timing of the closings is included in the work papers for PGE  
4 Exhibit 300.

**Table 3**  
**Capital Expenditures (\$millions)**

	<b>2009</b>	<b>2010</b>	<b>2011</b>
	<b>Forecast<sup>(1)</sup></b>	<b>Budget</b>	<b>Test Year</b>
Operational Expenditures	\$17.7	\$21.2	\$23.2
Wind: Biglow Canyon phases 2 & 3	398.7	200.6	0
Hydro Relicensing and Construction	26.3	11.8	28.0
Other <sup>(2)</sup>	8.3	16.4	80.1
Dispatchable Generation	4.0	4.4	4.4
<b>Total</b>	<b>\$455.0</b>	<b>\$254.4</b>	<b>\$135.6</b>

*(1) 9 months actual +3 months forecast*

*(2) Contains costs for Boardman Stator Rewind (2009 only) and Air Quality Controls (2009-2011)*

5 **Q. Please explain the major capital expenditures that took place in 2009.**

6 A. The major capital expenditures in 2009 were:

- 7
- 8 • Biglow Canyon phases 2 and 3 of the Biglow Canyon Wind Farm for \$222  
9 million and \$176.6 respectively.
  - 10 • At Colstrip, capital costs of \$6.6 million represent PGE's share within the scope  
11 of the ownership agreement. Examples of work completed are mercury and NOx  
12 controls, cooling tower maintenance, and a turbine-generator overhaul.
  - 13 • At Boardman, capital costs consisted of \$6.7 million to rewind the generator  
14 stator and perform generator improvements. The stator rewind was undertaken  
15 due to indications of deterioration to the existing stator bars. Generator  
16 improvements, including a conversion to water and hydrogen cooled stator bars,  
were performed in order to extend the life of the generator and improve reliability.

- 1       • The bypass stack dampers and foundation at Beaver were replaced totaling  
2       approximately \$2.0 million.
- 3       • A spare generator rotor was purchased for \$1.0 million at Boardman. The rotor  
4       was purchased in order to mitigate the potential for an extended plant outage upon  
5       rotor failure.
- 6       • There was \$0.9 million of work to upgrade the coal yard programmable logic  
7       controller system at Boardman.
- 8       • A total of \$0.7 million in other thermal fitness capital jobs were completed.  
9       These jobs include plant modifications for safety, reliability, and minor upgrades.
- 10      • At the North Fork facility, approximately \$0.5 million in capital expenses was  
11      related to installation of a new liner in the sewage lagoon.
- 12      • The CT excitation system at Beaver unit #2 was replaced for approximately \$0.3  
13      million.
- 14      • \$6.3 million of capital expenditures was for approximately 100 additional projects  
15      at many of PGE’s generation facilities, ranging from \$1,000 to \$300,000 in size.

16   **Q. Please explain the major expenditures in 2010 and 2011 in Table 3.**

17   A. The major expenditures are:

- 18      • Biglow Canyon phase 3 costs were \$200.6 million in 2010. The details of the  
19      project are discussed in PGE Exhibit 300.
- 20      • Capital expenditures for 2010 and 2011 at Boardman include combustion  
21      controls, a combustion monitoring system, a boiler cleaning system, and Sulfur  
22      dioxide (SO<sub>2</sub>) controls. The combustion controls include Low NO<sub>x</sub> Burners and  
23      Overfire Air ports. PGE also expects capital expenditures related to mercury

1 controls at Boardman in 2011. These total approximately \$16.4 million in 2010  
2 and \$80.1 million in 2011<sup>4</sup>.

- 3 • In 2010, \$8.2 million of capital expenses are to replace a turbine at Unit 3 at  
4 Colstrip. This represents PGE's share of the generating unit and provides the  
5 maintenance to maintain or improve reliability and efficiency within the scope of  
6 the ownership agreement.
- 7 • In 2010, \$3.0 million of expenditures are for thermal fitness. These jobs include  
8 plant modifications for safety, reliability, and minor upgrades.
- 9 • In 2010, hydro and wind fitness capital jobs totaling \$2.3 million are expected to  
10 be completed. These jobs include plant modifications for safety, reliability, and  
11 other upgrades.
- 12 • In 2010, the upper 30% of the boiler reheater at Boardman will be replaced for  
13 \$2.3 million.
- 14 • In 2010, approximately \$785,000 is for riparian temperature mitigation on the  
15 Columbia River to offset Port Westward wastewater effluent heat load. The  
16 mitigation, as mandated by the Oregon DEQ permit, requires the planting of trees  
17 on approximately 2 miles of stream bed (roughly 50 acres). Land used to plant  
18 the trees is placed into a 40-year conservation easement.
- 19 • In 2010, approximately \$547,000 is for reliability and safety upgrades to the bus  
20 system and station service system at the Oak Grove Plant.
- 21 • In 2010 and 2011, approximately \$11.8 million and \$26.7 million, respectively,  
22 are for hydro relicensing activities such as construction and professional services.  
23 These are described in more detail below.

---

<sup>4</sup> This represents 80% of the total cost.

- 1           • PGE plans to add 15 MW of DSG capacity per year for the next five years. The  
2           cost per additional kW is approximately \$290, which equals \$4.4 million in 2010  
3           and 2011.

4   **Q. Please explain the hydro relicensing work to be completed in 2009, 2010, and 2011.**

5   A. In 2009, capital expenditures for hydro relicensing and construction are \$26 million. This  
6   includes \$7 million for relicensing construction. In 2010, \$12 million for hydro relicensing  
7   and construction is expected. The 2010 closings include \$6.7 million for relicensing  
8   construction. The relicensing costs include professional services (e.g., outside consultants,  
9   engineering, research, financial, legal, accounting, and purchasing), AFUDC, direct labor,  
10   and tax and license fees associated with our Oak Grove and North Fork hydro facilities. In  
11   2011, capital expenditures for hydro relicensing and construction is \$28 million. The 2011  
12   expenses include \$13 million for relicensing construction and \$9 million for the River Mill  
13   Downstream Migrant Surface Collector.

14   **Q. Which strategic projects are closing prior to the end of 2011?**

15   A. We expect \$535.6 million of projects to close to plant during 2010 and 2011. These projects  
16   include Biglow Canyon phase 3, Clackamas relicensing, and Low NOx Burners, Mercury  
17   and SO<sub>2</sub> controls at Boardman. A discussion of rate base, including capital additions, is in  
18   PGE Exhibit 300.

19   **Q. Please describe the Clackamas relicensing costs that close to plant in 2010.**

20   A. \$65.6 million for Clackamas relicensing will close to plant by December 2010. The  
21   relicensing costs include professional services (e.g., outside consultants, engineering,  
22   research, financial, legal, accounting, and purchasing), AFUDC, direct labor, and tax and  
23   license fees associated with our Oak Grove and North Fork hydro facilities. As discussed  
24   below in Section IV, we expect to receive the license in mid- to late-2010; however, for

1 revenue requirement purposes we have made an assumption that these costs do not go into  
2 service until December 2010.

3 **Q. What is the purpose of the Low NO<sub>x</sub> burners, mercury and SO<sub>2</sub> controls at**  
4 **Boardman?**

5 A. The Oregon Regional Haze Rule requires installation of the Low NO<sub>x</sub> burners by July 2011.  
6 NO<sub>x</sub> emission limits will be reduced by 50% in 2011. The purpose of the Low NO<sub>x</sub> burners  
7 and Overfire Air ports is to achieve the required NO<sub>x</sub> levels of less than 0.23 lb / MMBTU  
8 (annual average) and 0.28 lb / MMBTU (30-day average).

9 The mercury controls project will install a sorbent injection system upstream of the  
10 currently operating electrostatic precipitator (ESP). Mercury will be adsorbed onto the  
11 sorbent material and captured by the ESP before it can be released to the atmosphere. The  
12 Oregon Utility Mercury Rule requires mercury controls to be installed and operating by July  
13 2012. Per this rule, PGE will need to reduce the level of mercury emissions by 90% or less  
14 than 0.6 lbs/TBTU.

15 The SO<sub>2</sub> controls project will install a semi-dry flue gas desulfurization system which  
16 would cut SO<sub>2</sub> emissions by 12,000 tons per year for an 80 percent reduction. These controls  
17 must be installed by July 2014, and are not included in the 2011 test year ratebase.

18 **Q. Is PGE planning any plant upgrades at Coyote Springs in 2011?**

19 A. Yes. PGE is planning a major upgrade to Coyote Springs that will include a new compressor  
20 rotor, blades, vanes and casings, new turbine rotor, 7241 buckets, nozzles and casings, new  
21 Dry Low NO<sub>x</sub> (DLN) Model 2.6 combustion system, new casing temperature management  
22 system, and new cooling optimization package. This upgrade will result in both increased  
23 capacity and an improved heat rate. A new Mark Ve control system will also enhance  
24 system control capabilities. PGE's customers will realize significant system generation cost

1 savings as a result of the upgrade. The benefits of the Coyote Springs upgrade are also  
2 discussed in PGE Exhibit 200.

3 **Q. What is the total cost of the Coyote Springs upgrade?**

4 A. The total cost included in revenue requirement of the upgrade is \$27.2 million.<sup>5</sup>

5 **Q. What are the net system benefits of the Coyote Springs upgrade?**

6 A. The estimated present value of the net benefits over the lifetime of the operation of the plant  
7 is \$80 million. System benefits resulting from the upgrade include avoided equipment  
8 replacements, maintenance agreement savings and the value of increased generation and  
9 improved efficiency (i.e., lower heat rate). The economic analysis demonstrating the  
10 positive net present value for this upgrade is included as confidential PGE Exhibit 703C.

11 **Q. Could system benefits from the Coyote upgrade be even greater?**

12 A. Yes. The agreement with the contractor includes incentives for achieving greater increases  
13 in plant capacity and bigger improvements in plant heat rate. The \$80 million net present  
14 value figure does not include the benefits and costs associated with these possible increases  
15 in system performance.

16 **Q. Is the Selective Water Withdrawal (SWW) project complete?**

17 A. Yes. The SWW was substantially completed and all major components were connected on  
18 December 3, 2009. A settlement was reached among the parties and was approved by the  
19 OPUC on January 22, 2010 (Order No. 10-020). PGE has tested the facility and as of  
20 January 20, it was closed to plant and rates went into effect February 1, 2010.

---

<sup>5</sup> This amount is a preliminary estimate and does not include \$3.7 million in contingency costs because of time constraints.

**D. Environmental Services**

1 **Q. Why are you discussing Environmental Services in the Generation testimony?**

2 A. Environmental Services (ES) provides general support to all PGE facilities, including  
3 generation. Some examples of the activities are monitoring of wildlife, fisheries, air quality  
4 and waste management/disposal. In addition, ES has experienced significant charges in the  
5 past several years that are likely to further escalate and are discussed in detail later in this  
6 testimony.

7 **Q. What is PGE’s forecast for environmental costs in 2011?**

8 A. PGE is forecasting environmental costs to be \$6.5 million, which represents an increase of  
9 \$3.2 million since 2008. The costs consist of project specific costs and general  
10 Environmental Services support (A&G) related to PGE’s various generation facilities.  
11 Table 4 below provides a summary of environmental costs for both categories.

**Table 4**  
**Environmental Costs**  
**(000s)**

	<b>2008</b>	<b>2011</b>
	<b>Actuals</b>	<b>Forecast</b>
Pelton Round Butte	\$746.0	\$2,210.8
Generation Support	856.3	1,489.3
Cleanup Projects	623.2	1,611.9
Miscellaneous	1,026.5	1,226.1
<b>Total Environmental Services Costs</b>	<b>\$3,252.0</b>	<b>\$6,536.1</b>

12 **Q. Why have costs increased?**

13 A. There are three major components of the increase, each of which will be discussed in more  
14 detail later in this testimony. The first component is the Pelton Round Butte projects. PGE  
15 is required as part of FERC relicensing of Pelton-Round Butte to complete various projects,  
16 which account for \$1.4 million of the increase.

17

1 The second component is related to three environmental cleanup projects: Portland  
2 Harbor, Oak Grove, and Harbor Oil. Costs have increased \$1 million since 2008 to \$1.6  
3 million. Activities associated with these projects will continue to intensify beyond 2011.

4 The third component is related to Environmental Services general support at PGE's  
5 generation facilities. In 2011, generation support costs are expected to be \$1.6 million, an  
6 increase of \$0.5 since 2008.

***1. Pelton-Round Butte Projects***

7 **Q. What is forecasted in 2011 for the Pelton-Round Butte projects?**

8 A. As shown in Table 5 below, we are forecasting \$2.2 million, an increase of \$1.4 million  
9 since 2008.

**Table 5**  
**Pelton Round Butte Projects**  
**(000s)**

	<b>2008 Actuals</b>	<b>2011 Forecast</b>
Fishway Pathways	\$125.3	\$1,015.3
Round Butte Hatchery	353.1	442.3
Fish Health Funding	-	207.3
Deschutes River Gravel Study	45.2	194.5
Terrestrial Resource Mgt	71.4	142.0
Miscellaneous	151.0	209.4
<b>Total</b>	<b>\$746.0</b>	<b>\$2,210.8</b>

10 **Q. Please describe the projects at the Pelton and Round Butte hydro facilities.**

11 A. PGE has completed the Selective Water Withdrawal in the forebay at Round Butte Dam. It  
12 is designed to capture downstream migrating juvenile salmon and steelhead from the  
13 Crooked, Metolius, and upper Deschutes rivers, which will then be trucked around the three  
14 dams and released into the lower Deschutes River for the first time since 1968. In addition,  
15 we perform ongoing activities, such as monitoring fish and wildlife, water quality, and  
16 hazardous waste management and disposal. Five significant projects include: 1) Section 18  
17 Fishway Pathways and Lamprey Studies, 2) Fish Facility Operations (Round Butte

1 Hatchery), 3) ODFW Cooperative Agreement / Fish Health Funding, 4) Lower Deschutes  
2 River Gravel Study, and 5) Terrestrial Resource Management Plan.

**Section 18 Fishway Pathways and Lamprey Studies**

3 **Q. Please describe the Fishway Pathways and Lamprey Studies.**

4 A. The Fishway Pathways and Lamprey Studies implement the fish passage (section 18  
5 prescriptions) issued by the U.S. Fish and Wildlife Service (USFWS) and National Oceanic  
6 and Atmospheric Administration (NOAA) Fisheries. Prescription 1 issued by each federal  
7 agency requires PGE to implement the Fish Passage Plan. This plan includes the  
8 construction of new or reconstruction of historic fish passage facilities at Round Butte,  
9 Pelton, and the Regulating Dams. After completion, additional fishway prescriptions require  
10 that these facilities be tested, and then operated. Successful operation is measured by the  
11 proportion of anadromous salmon and steelhead smolts that enter the reservoir from the  
12 tributaries and are safely captured and transported around the hydro project. Pursuant to  
13 Prescription 18, USFWS requires the completion of a Pacific Lamprey passage evaluation  
14 and mitigation plan. This plan was approved by FERC on November 8, 2006 and is now  
15 being implemented.

**Round Butte Hatchery Project**

16 **Q. Please describe the Round Butte Hatchery Project.**

17 A. The FERC License directs PGE and the Confederated Tribes of Warm Springs (Tribes) to  
18 enter into an agreement with ODFW for the operation of Round Butte Fish Hatchery at no  
19 more than the current production levels of spring Chinook and summer steelhead during the  
20 term of the license. This agreement was approved by FERC in September 2006. The  
21 requirement to operate new and/or reconstructed fish passage facilities at Pelton Round  
22 Butte on a year-round basis has been the primary factor for increased costs projected for the

1 Section 18 Fishway Pathway program in 2010 and 2011. Another factor contributing to  
2 increased costs is the FERC license requirement to conduct several test and verification  
3 studies to evaluate the effectiveness of new fish passage facilities and the fish passage  
4 program. A majority of these operating costs had previously been capitalized prior to  
5 completion of the SWW and new fish passage facilities.

**Fish Health Funding Project**

6 **Q. Please describe the ODFW Cooperative Agreement / Fish Health Funding Project.**

7 A. The FERC license directs PGE and the Tribes to enter into an agreement with the ODFW to  
8 fund two positions. One of these positions is a Mitigation Coordinator, the other a Fish  
9 Health Specialist. PGE and the Tribes are required to develop and file with FERC a plan for  
10 a Fish Health Management Program (the Program) at Pelton-Round Butte. The Program  
11 will support the fish passage effort, monitor disease incidence in Deschutes River fish  
12 populations and potential changes in the distribution of fish disease agents. This Program  
13 was approved by FERC on January 31, 2007. The program provides for the evaluation of  
14 disease as a mortality factor in downstream and upstream migrating anadromous salmonids  
15 and procedures needed to reduce the risk of transmitting pathogens upstream of the Project.  
16 Projected costs increase in 2010 and 2011 because we were able to capitalize charges in  
17 2008.

**Lower Deschutes River Gravel Study**

18 **Q. Please describe the Lower Deschutes River Gravel Study.**

19 A. The FERC License required PGE to first file and then implement a plan to evaluate gravel  
20 mobility, supply, and use by spawning salmonids in the lower Deschutes River from the  
21 Reregulating Dam to Trout Creek confluence. This project implements the lower river

1 gravel study plan, which has a sediment transport monitoring component, an experimental  
2 gravel augmentation component, and a biological (fish use) component.

**Terrestrial Resource Management Plan**

3 **Q. Please describe the Terrestrial Resource Management Plan.**

4 A. The FERC License directs PGE to develop, file, seek approval, and implement a Terrestrial  
5 Resources Management Plan (TRMP). The TRMP is the principal instrument for  
6 management of, implementation, monitoring and adaptation of Protection Mitigation and  
7 Enhancement Measures for terrestrial resources affected by or related to the hydro Project.  
8 The TRMP was approved by FERC in November 2006 and implemented in 2009.

**2. Environmental Cleanup**

9 **Q. Please describe the cleanup activities PGE is undertaking.**

10 A. PGE is involved with three environmental cleanup projects at this time. Two of the sites are  
11 Environmental Protection Agency (EPA) designated Superfund Sites: Portland Harbor and  
12 Harbor Oil. The third site is at PGE's Oak Grove facility, located on U.S. Forest Service  
13 land. The Oak Grove facility has two components: 1) Polychlorinated biphenyl (PCB)  
14 cleanup, and 2) lead abatement at identified pipe trestles.

15 **Q. What is the forecasted environmental cost increase for Portland Harbor, Harbor Oil,  
16 and Oak Grove from 2008 to 2011?**

17 A. We are forecasting an increase of \$970,000 from 2008 to 2011 for Environmental Costs.  
18 The remediation of Oak Grove is budgeted separately. Aside from the Oak Grove cleanup  
19 costs, the majority of the increase is related to the Portland Harbor project, which includes  
20 the Downtown Reach section. Table 6 below summarizes the costs of each of these projects  
21 in 2008 and 2011. These represent investigation costs (except for Oak Grove) only and do  
22 not include remediation or actual cleanup costs.

**Table 6**  
**Cleanup Costs**  
**(000s)**

	<b>2008</b>	<b>2011</b>
	<b>Actuals</b>	<b>Forecast</b>
Portland Harbor	\$496.9	\$1,212.4
Harbor Oil	126.3	65.1
Oak Grove	0.0	334.4
<b>Environmental Costs</b>	<b>\$623.2</b>	<b>\$1,611.9</b>
Oak Grove remediation	10.0	2,044.2
<b>Grand Total</b>	<b>\$633.2</b>	<b>\$3,656.1</b>

1 We discuss these three projects below.

**Portland Harbor**

2 **Q. Please describe the Portland Harbor project.**

3 A. The Portland Harbor Superfund Site (Portland Harbor) currently extends from  
 4 approximately mile 2 through mile 12 of the Willamette River<sup>6</sup>. The EPA began an  
 5 investigation of the site in 1997, and based upon that investigation, initially sent “Notices of  
 6 Potential Liability” to 69 parties, including PGE, formally identifying them as Potentially  
 7 Responsible Parties (PRPs) under the Comprehensive Environmental Response,  
 8 Compensation, and Liability Act (CERCLA).<sup>7</sup> There are now hundreds of parties under  
 9 investigation and the EPA has assigned formal PRP status to approximately 80 parties. A  
 10 small portion of these PRPs (approximately 10) formed the Lower Willamette Group  
 11 (LWG) and are concluding a Remedial Investigation (RI) of the site and are conducting a  
 12 Feasibility Study (FS). PGE did not wish to incur significant up front costs and perform the  
 13 RI/FS and, thus, is not a party to the LWG agreement. Although costs associated with an  
 14 RI/FS must be borne by all PRPs, getting other parties to contribute must be accomplished

<sup>6</sup> For additional detail, the United States Environmental Protection Agency has posted the map in Exhibit 1 at [http://yosemite.epa.gov/R10/CLEANUP.NSF/ph/Uplands/\\$FILE/Portlandharbormaplg.jpg](http://yosemite.epa.gov/R10/CLEANUP.NSF/ph/Uplands/$FILE/Portlandharbormaplg.jpg)

<sup>7</sup> The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), commonly known as Superfund, was enacted by Congress on December 11, 1980. This law created a tax on the chemical and petroleum industries and provided broad Federal authority to respond directly to releases or threatened releases of hazardous substances that may endanger public health or the environment.

1 through an allocation<sup>8</sup> process or through expensive contribution litigation. The estimate for  
2 RI/FS costs incurred so far is \$75 million and will be allocated among the PRPs in the  
3 future; a specific date is not known at this time.

4 EPA’s investigations indicate the presence of polychlorinated biphenyls (PCBs), a  
5 chemical used in various types of electrical equipment including transformers, at the  
6 Portland Harbor site. For this reason, in January 2008, the EPA served PGE with a formal  
7 information request<sup>9</sup> that included more than 80 questions regarding “any Property you  
8 currently own, lease, operate on, or otherwise are affiliated or historically have owned,  
9 leased, operated on, or otherwise been affiliated with” from 1937 to the present, within  
10 approximately 800 feet of the Willamette River between River miles 2 through 16. PGE has  
11 operated since the 19th century on numerous properties in the area identified by the 104(e)  
12 Information Request. PGE has prepared and submitted responses to the EPA’s requests.

13 Under CERCLA, PGE’s potential liability as a PRP includes claims for site assessment  
14 costs, cleanup costs, damages to natural resources, state and federal oversight costs, and  
15 remediation and restoration costs. PGE is actively participating in developing and  
16 implementing possible settlement proposals that would divide the cost of investigating and  
17 remediating the site among all the participating PRPs. We expect this process to take  
18 several years. It has involved, and will continue to involve, substantial costs associated with  
19 internal investigations, documentation generation and evaluation, the hiring of consultants  
20 and other contractors to assist in complying with EPA and Oregon DEQ procedures, internal  
21 administration, and legal representation in the CERCLA PRP liability allocation  
22 negotiations.

---

<sup>8</sup> PRPs typically will engage in a voluntarily settlement process to allocate remediation cost and performance responsibility. This process, known as an “Allocation”, usually involves hiring an Allocator who will aid the parties in determining how to apportion the costs among themselves.

<sup>9</sup> This request was pursuant to CERCLA Section 104(e) (a “104(e) Information Request”).

1 **Q. What is PGE's involvement in Downtown Reach?**

2 A. Downtown Reach includes river miles 12 through 16 of Portland Harbor and is currently  
3 regulated by the Oregon DEQ. The Oregon DEQ has issued PGE a unilateral order  
4 requiring participation in the evaluation and possible cleanup of particular areas in the  
5 Downtown Reach. The process will involve site assessments and river sampling with  
6 possible remediation required in the uplands and in the river.

7 **Q. What processes are currently in progress?**

8 A. For Portland Harbor, the LWG is in the process of conducting the RI/FS for Portland  
9 Harbor. PGE expects the LWG to complete a draft RI in early 2010. A final RI is expected  
10 in Fall 2010. PRPs, including PGE, are currently in the process of selecting an Allocator,  
11 and with candidate interviews having been conducted. Due to lack of consensus in the  
12 LWG, the Allocator position has not yet been filled.

13 **Q. What are the next steps in the process?**

14 A. After a draft of the Feasibility Study is submitted in Fall 2010 and once EPA settles on a  
15 final remedy, it will issue a Record of Decision (ROD), which we expect in June 2012. The  
16 ROD will indicate EPA's areas of concern, the types of remedial actions EPA expects to be  
17 implemented, and the contaminant level at which these areas would be considered  
18 remediated.

19 In the meantime, PRPs are working through the allocation process. Once an Allocator  
20 is selected, parties will share 104(e) information request responses and begin allocation  
21 discussions. PGE currently expects an Allocation Report to be generated by the Allocator in  
22 May 2012. Then, PRPs will resume discussions and submit a good faith offer to EPA,  
23 probably in the Fall of 2012. Consent Decree negotiations are expected to begin the  
24 following spring with a Consent Decree entered by EPA in December 2013. The Consent

1 Decree will indicate which PRPs are responsible for performance of the remedy, and will  
2 likely specify their allocation of the remediation costs.

3 **Q. Does PGE have control over the timing of these processes?**

4 A. No. PGE is one of many PRPs and is not a member of the LWG. The EPA and LWG are  
5 dictating the pace.

**Oak Grove**

6 **Q. Please describe the Oak Grove project.**

7 A. PGE operates the Oak Grove facility, which is located on federal lands administered by the  
8 Forest Service, pursuant to a FERC license. In August 2005, PGE retained environmental  
9 consultants to perform a site investigation of potential petroleum contamination discovered  
10 near the maintenance shop at the Oak Grove facility. The site investigation was conducted  
11 in five phases between August 2005 and April 2008. The consultants discovered petroleum  
12 contamination in the area of the maintenance shop, which PGE has remediated. The  
13 consultants also discovered PCB contamination downhill of a storm water outfall near the  
14 maintenance shop. The contamination appears to be limited to surface soils and does not  
15 extend to the nearby Clackamas River.

16 In April 2008, the Forest Service notified PGE that Forest Service oversight and  
17 approval of any cleanup under a mutually negotiated "Settlement Agreement and  
18 Administrative Order on Consent" (AOC) would be required before cleanup could  
19 commence. The Forest Service issued a 104(e) Information Request to produce all  
20 documents and certain information related to the Oak Grove PCB spill. On July 11 and  
21 August 9, 2008, PGE submitted information and documents to the Forest Service.

22 Additionally, on September 17, 2008, PGE sent formal notification to the U.S. Forest  
23 Service of potential lead contamination of the area under the Cripple Creek, Pint Creek, and

1 Canyon Creek support trestles. In 1968, 1970, and 1971 PGE sandblasted the trestles (one  
2 per year) in preparation for re-painting, and then re-painted the trestles in accordance with  
3 Oregon DEQ protocols in place at the time. In June 2005, PGE began preparation to again  
4 re-paint the trestles. However, in the process of preparing the trestles, soil testing was  
5 conducted to ensure the painting company was not contributing to any previous  
6 contamination in the area. PGE and an environmental consultant took soil samples, which  
7 were then analyzed for eight Resource Conservation and Recovery Act (RCRA) heavy  
8 metals. Testing confirmed that several samples exceeded the limit levels for Arsenic,  
9 Cadmium, Chromium, Lead, and Silver.

10 **Q. What processes are currently in progress and what are the next steps?**

11 A. Regarding the PCB cleanup, PGE has completed the Engineering Evaluation/Cost Analysis  
12 (EE/CA) for the site and submitted the results to the Forest Service. PGE expects to cleanup  
13 the site in summer 2010.

14 Regarding lead contamination, PGE has notified the Forest Service and is waiting for its  
15 determination on the site for cleanup protocol. PGE expects the Forest Service to require  
16 resolution of the lead contamination issue in a comprehensive Administrative Order on  
17 Consent (AOC) under CERCLA. PGE anticipates further investigation in 2010 and cleanup  
18 activities to occur in 2011. The cost of the cleanup (\$2 million) is included in the Oak  
19 Grove O&M expenses as shown in Table 6 above.

**Harbor Oil**

20 **Q. Please provide some background on the Harbor Oil project.**

21 A. Harbor Oil, Inc. (Harbor Oil), an oil re-refiner located in north Portland, was utilized by  
22 PGE to process used oil from our power plants and electrical distribution system from at

1 least 1990 until 2003. Harbor Oil was also utilized by other entities for the processing of  
2 used oil and other lubricants.

3 In 1974 and 1979, major oil spills occurred at the Harbor Oil site that impacted an  
4 approximately two-acre area. Elevated levels of contaminants, including metals, pesticides,  
5 and PCBs, have been detected at the site. On September 29, 2003, Harbor Oil was added to  
6 the federal National Priority List as a federal Superfund site.

7 PGE received a Special Notice Letter for RI/FS from the EPA, dated June 27, 2005, in  
8 which PGE was named as one of 14 PRPs with respect to the Harbor Oil site. The letter  
9 started a period for the PRPs to participate in negotiations with the EPA to reach a  
10 settlement to conduct or finance an RI/FS of the Harbor Oil site. On May 31, 2007, an  
11 Administrative Settlement Agreement and Order on Consent was signed by the EPA and six  
12 other parties, including PGE, to implement an RI/FS at the Harbor Oil site. The final  
13 revised work plan for the RI/FS has been submitted to the EPA, and phases 1 and 2 of the  
14 site characterization are complete.

15 **Q. What processes are currently in progress and what are the next steps?**

16 A. Risk assessments for human health and ecological risks are in progress. The RI report is  
17 scheduled to be submitted to EPA in 2010. The Feasibility study is scheduled to be  
18 completed in 2011. Once the RI/FS is completed, EPA will provide a ROD to all parties  
19 identifying the remedy and costs.

20 **Q. What is PGE's forecast for the remaining costs for this project?**

21 A. PGE's preliminary forecasts for 2010 and 2011 are included in Confidential PGE Exhibit  
22 102. These amounts are based on known and measurable costs but do not include the  
23 potentially significant costs associated with additional investigation, allocation, and  
24 remediation.

3. *General Support at Generation Facilities*

1 **Q. Please describe some of the activities that Environmental Services performs at various**  
2 **PGE plants.**

3 A. Table 7 below shows environmental costs at PGE’s generating facilities.

**Table 7**  
**Environmental Costs by Entity**  
**(000’s)**

	<b>2008</b>	<b>2011</b>
	<b>Actuals</b>	<b>Forecast</b>
Hydro Facilities	\$389.7	\$705.4
Biglow	247.6	557.8
Boardman	127.9	81.4
Beaver	12.6	74.1
Port Westward	52.1	17.9
Miscellaneous	26.4	52.8
<b>Total</b>	<b>\$856.3</b>	<b>\$1,489.3</b>

4 At Biglow Canyon Wind Farm, we are required by federal and state agencies (FERC  
5 and Oregon Energy Facility Siting Council-EFSC) to monitor wildlife and help manage  
6 hazardous waste and disposal issues. These costs increase because all phases of Biglow  
7 Canyon are expected to be operating in 2010 and 2011.

8 At PGE’s Clackamas hydro facility, we are expecting a license early 2010 and there  
9 will be several projects to do as a condition of the re-license.

10 At the Boardman plant, PGE has been working with state and federal regulators over  
11 the past three years to adopt a plan to reduce emissions from the plant. We continue to work  
12 closely with the OPUC, Oregon DEQ, and interested stakeholders as we discuss the fate of  
13 the Boardman facility. Other activities include fish and wildlife activities, water quality  
14 monitoring, and hazardous waste management and disposal.

15 At Port Westward, we are required by the federal (FERC) and state agencies (EFSC) to  
16 monitor wildlife (bald eagle nests), air quality, water quality, emissions, and temperature  
17 mitigation. We also assist with hazardous waste disposal issues.

1           The new FERC license for the Clackamas Project will require a significant  
2           increase for implementing aquatic projects and evaluating new fish facilities to ensure they  
3           meet protection standards.

***4. True-up Mechanism***

4   **Q. Environmental Services expects to spend \$6.5 million in 2011, yet there are several**  
5   **Superfund sites included whose timing and funding is uncertain. How does PGE**  
6   **propose to mitigate this uncertainty?**

7   A. PGE proposes a balancing mechanism that would track variances from Superfund (or  
8   Superfund-like) projects included in a balancing account.

9   **Q. What type of projects would be included in the balancing account?**

10   A. PGE’s proposed balancing account mechanism would include only those projects where  
11   PGE has been identified as a responsible party by a federal or state agency. These projects  
12   would be Portland Harbor, Harbor Oil, and Oak Grove (Lead Abatement and PCBs).  
13   Portland Harbor and Harbor Oil are declared by the EPA to be Superfund Sites. Although  
14   Oak Grove is not a Superfund Site, it has Superfund-like characteristics.

15   **Q. How would the balancing account work?**

16   A. The baseline amount would be included in the test year. The balancing account would track  
17   differences between actual and forecasted costs. Any amounts accrued in the balancing  
18   account would earn interest at PGE’s cost of capital and would be subject to a prudence  
19   review and/or audit.

20   **Q. How often would the balancing account be reviewed?**

21   A. The account would be reviewed at the time of a general rate case or at least every two years.

22   **Q. What are the benefits to customers of this balancing account mechanism?**

- 1 A. Environmental projects can sometimes take decades to resolve. During this time, it is very  
2 difficult to accurately forecast costs and potential insurance proceeds received that offset  
3 these costs. The balancing account minimizes volatility by enabling PGE to track actual  
4 costs versus forecasts, and review (and reset, if necessary) the account on a regular two-year  
5 cycle.

#### IV. Cost Efficiency in Generation

1 **Q. Has PGE implemented cost efficiency programs in the generation plants?**

2 A. Yes. As summarized in PGE Exhibit 200, PGE has taken several steps toward cost savings  
3 and cost efficiency in the generation plants.

4 • Union Contract Negotiation: Although unions usually limit a worker's job  
5 description, in its most recent 3-year contract with IBEW Local 125, PGE  
6 negotiated to expand the roles and responsibilities of Port Westward and Coyote  
7 Springs union employees. Thus, instead of hiring additional workers to complete  
8 extra tasks, PGE can assign those tasks to existing employees. This keeps our  
9 workforce leaner and reduces hiring, labor, and labor related costs.

10 • Biglow Warehouse Heating: In the coldest winter months, the cost to heat the  
11 Biglow warehouse with propane averaged \$600-900 per week. The Biglow staff  
12 teamed up with PGE's Power Supply Engineering Services to install a waste oil  
13 burner in early 2009, which burns used motor oil and waste oil from the turbines.  
14 The system will not only pay for itself in less than four years, but is also an  
15 environmentally safe and friendly way of disposing of the waste oil.

16 • DSG: By the end of 2010, PGE will have 31 DSG sites with a total capacity of  
17 75.2 MW. These resources are most useful during extreme temperature changes  
18 and emergencies, when PGE's system is under strain and provides needed  
19 reserves. To meet the load without these DSG sites, PGE would be forced to buy  
20 power in the market, and when demand is high and supply is low, prices escalate  
21 quickly. Therefore, the DSG sites provide low-cost power when PGE customers  
22 need it most.

- 1           • Turbine upgrade at Coyote: As discussed above in Section III-C, this 2011  
2 upgrade will increase the efficiency of operations at the Coyote plant. The  
3 upgrades include:

- 4                     ▪ A new compressor and turbine rotor  
5                     ▪ Higher temperature nozzles, blades and seals for the power turbine  
6                     ▪ New compressor and turbine casings  
7                     ▪ A new dry low NOX combustion system  
8                     ▪ A Mark Ve control upgrade

9           These upgrades will result in 15MW of additional capacity and an improved heat  
10 rate. The upgrades will reduce inspection requirements, extend the life of the  
11 rotors, and promote more reliable operation. The new control system permits a  
12 larger plant operating range and more dispatch flexibility which can aid in the  
13 integration of wind resources into the PGE system. This project was discussed  
14 above in Sections III-A-2 and III-C.

- 15           • Generation Excellence: In 2006, PGE started the Generation Excellence program,  
16 which focuses on plant efficiency, reliability, and continuous improvement. A  
17 major part of this program is Reliability Centered Maintenance (RCM), which  
18 works to increase plant availability and reliability through optimized planned  
19 maintenance. Once plant management identifies critical systems with frequent  
20 failures or costly reactive maintenance, the RCM group can begin a study of the  
21 system's operation and maintenance to determine the optimal preventative  
22 maintenance schedule. Through the analysis of critical plant components, we are  
23 able to optimize the maintenance for these systems, reduce breakdowns and  
24 increase reliability and availability. By reducing breakdowns that lead to forced

1 outages, we also reduce replacement power costs – PGE is not forced to buy from  
2 the wholesale market when a plant is suddenly unavailable.

3 **Q. Has the RCM program identified specific preventive maintenance projects that led to**  
4 **savings?**

5 A. Yes. There are several examples of RCM success in the past few years.

- 6 • In 2006, RCM analysis was performed on the sootblower system and the  
7 pulverizers at the Boardman coal-fired plant. The sootblowers use water and  
8 steam to clean the ash that adheres to the tube surfaces. The ash build up on the  
9 tube surfaces affects heat transfer and the efficiency of the system. The analysis  
10 of the system caused us to increase the number and frequency of inspections,  
11 catch potential failures before they occurred, improve performance and reduce  
12 corrective maintenance costs.
- 13 • The pulverizer grinds coal into a fine powder for combustion in the boiler – an  
14 important part of the generation process. The analysis helped us to identify the  
15 maintenance activities that would prevent the most common failures in the  
16 pulverizers. In 2007, the labor and material costs for the pulverizers between  
17 January and July were about \$350,000. In 2009, the same costs in the same  
18 period were much lower, approximately \$100,000.
- 19 • The RCM group performed an analysis on the reheater section of the boiler at  
20 Boardman. A reheater leak can take the plant offline for up to four days, costing  
21 the plant as much as \$2 million, or \$500,000 per day in replacement power alone.  
22 Through the RCM analysis, we were able to forecast expected reheater tube leaks  
23 in the coming years and make a cost-effective decision to replace the upper  
24 section of the reheater.

1 **Q. How expansive is the RCM program?**

2 A. As of early 2010, RCM analysis has been performed on generation equipment at seven  
3 different plants, in addition to the sootblower and pulverizer at Boardman. At Port  
4 Westward, RCM has been used to analyze the circulating water system, the feedwater  
5 system, the wastewater system, the gas turbine lube oil, and the heat-resistant steam  
6 generator. At Coyote Springs, studies have been performed for the gas turbine, the gas  
7 turbine auxiliaries, and the ammonia system. RCM has also analyzed the 4160V breakers at  
8 the Beaver Plant. At Westside Hydro, RCM analysis has been performed on Units 1 and 2  
9 at North Fork, and Units 1 and 2 at Oak Grove. Finally, the RCM group analyzed Round  
10 Butte Units 1, 2, and 3.

**V. Hydro Relicensing Update and Related Revenue Requirement**

1 **Q. What is the status of the relicensing process for PGE’s hydro projects - Willamette**  
2 **Falls, Pelton Round Butte, and Clackamas?**

3 A. PGE has obtained FERC licenses for the Willamette and Pelton Round Butte projects, and is  
4 in the process of obtaining a long-term license for the Clackamas projects.

5 **Q. What is the status of PGE’s Clackamas Project relicensing process?**

6 A. We received a Water Quality Certification for the Clackamas River in June 2009. This is  
7 one of the final steps before a new license can be issued. We anticipate a FERC-issued  
8 license for the Clackamas projects in mid-2010.

9 **Q. What licensing structure supports operation of the Clackamas Project prior to**  
10 **issuance of a new long-term license?**

11 A. The four facilities included in the Clackamas Project were previously covered by two  
12 separate long-term licenses for the Oak Grove and North Fork Projects. These licenses  
13 expired on August 31, 2006. An “annual license” allows the four plants to continue  
14 operation under the terms of the Oak Grove and North Fork Project licenses while FERC  
15 considers the new long-term Clackamas Project application.

16 **Q. Do the hydro O&M expenses you discussed in Section III-A-4 of your testimony**  
17 **include costs associated with protection, mitigation, and enhancement measures**  
18 **required by the new long-term licenses?**

19 A. Yes. For example, the hydro O&M figures in Table 1 above include costs required for Fish  
20 Committee support at Faraday and protection, mitigation and enhancement measures at  
21 Timothy Lake.

22 **Q. At the time PGE decided to pursue new long-term hydro licenses, OPUC Order No.**  
23 **89-507 governed the integrated resource planning process. This order directed utilities**

1        **to consider both cost and risk in their resource decisions. Do PGE’s hydro relicensing**  
2        **decisions meet the Order No. 89-507 criteria?**

3        A. Yes. With respect to expected costs, PGE’s UE 180 testimony, PGE Exhibit 300, Section III  
4        (included as PGE Exhibit 704) explained that the estimated costs of relicensing hydro  
5        resources compared very favorably to the costs of other alternatives at the time PGE decided  
6        to seek new long-term licenses. With respect to risk, relicensing compares very favorably  
7        with other alternatives. The costs incurred to meet the license conditions will almost all be  
8        fixed, whereas the costs of other resource alternatives will be subject to much more variation  
9        over time – changing market electric prices, changing fuel prices, possible changes related to  
10       CO<sub>2</sub> standards, etc.

**VI. Qualifications**

1 **Q. Mr. Quennoz, please describe your qualifications.**

2 A. I hold a Bachelor of Science degree in Applied Science from the U.S. Naval Academy and  
3 hold Masters Degrees in Operations Analysis from the University of Arkansas, Mechanical  
4 Engineering from the University of Connecticut, Nuclear Engineering from North Carolina  
5 State University, and an MBA from the University of Toledo. Prior to working for PGE, I  
6 held positions as Plant Superintendent at the Davis-Besse Nuclear Station for Toledo Edison  
7 and General Manager at the Arkansas Nuclear One Station for Arkansas Power and Light. I  
8 also coordinated restart of the Turkey Point Nuclear Station for Florida Power and Light. I  
9 joined PGE in 1991 and served as Trojan Plant General Manager and Site Executive. I  
10 assumed responsibilities for thermal operations in 1994 and hydro operations in 2000. I was  
11 appointed Vice President, Nuclear and Thermal Operations in 1998, and Vice President  
12 Generation in 2000. I've held my current position of Vice President, Power Supply since  
13 August 2004. My responsibilities include overseeing all aspects of PGE's power supply, as  
14 well as the decommissioning of the Trojan nuclear plant. I am a registered Professional  
15 Engineer (P.E.) in the State of Ohio.

16 **Q. Ms. Behbehani, please describe your qualifications.**

17 A. I received a Bachelor of Science degree in Architectural Engineering from Roger Williams  
18 University in 1982, and am enrolled in the Master of Business Administration program at  
19 Marylhurst University. I have worked on Nuclear, Coal, Gas, Hydro and Wind facilities for  
20 almost my entire career. In 1997, I joined PGE as a Civil Engineer in Power Supply  
21 Engineering and began serving as Manager of Environmental Services in 2007.

22 **Q. Does this conclude your testimony?**

23 A. Yes.

**List of Exhibits**

<b><u>PGE Exhibit</u></b>	<b><u>Description</u></b>
701	Generating Resource Summary
702	IR and PTP Transmission Resource Summary
<b>703C</b>	<b>Coyote Turbine Upgrade Economic Analysis – Confidential</b>
704	Section III of PGE Exhibit 300 in Docket UE 180