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I. Introduction

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

2 A. My name is Alex Tooman. I am a project manager for PGE. I am responsible, along with
3 Mr. Tinker, for the development of PGE's revenue requirement forecast. In addition, my
4 areas of responsibility include affiliated interest filings, results of operations reporting, and
5 other regulatory analyses.

6 My name is Jay Tinker. I am also a project manager for PGE. My areas of
7 responsibility include revenue requirement and other regulatory analyses.

8 Our qualifications appear at the end of this testimony.

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

10 A. The purpose of our testimony is to present PGE's \$1,811.0 million revenue requirement for
11 the 2011 test period. On an average rate base of \$3,243.6 million, this revenue requirement
12 will allow PGE an opportunity to earn an 8.289% rate of return that includes a 10.50%
13 return on average common equity of 50% in 2011. PGE Exhibit 301 summarizes the
14 development of PGE's 2011 revenue requirement.

15 In addition to presenting this integrated or bundled revenue requirement, we also
16 present and discuss our unbundled revenue requirement in Section XI.

17 **Q. What increase in rates does PGE request in this proceeding?**

18 A. PGE's revenue requirement is \$125.2 million higher in 2011 than the revenues we would
19 expect based on 2010 prices, which reflect approved rates in UE 189, UE 197, UE 204,
20 UE 208, and UE 209. Therefore, PGE requests that rates be adjusted on January 1, 2011, to
21 yield \$125.2 million of additional revenues (a 7.4% increase overall) on an annualized basis.
22 PGE Exhibit 1500 describes the prices PGE proposes to allow an opportunity to recover our
23 2011 revenue requirement.

1 **Q. Does the requested increase reflects the management discretionary items described in**
2 **PGE Exhibit 100 to help limit the size of the requested increase?**

3 A. Yes. We adjusted the revenue requirement to reflect the two items described in PGE Exhibit
4 100. The approximate revenue requirement impact of the adjustments total \$23 million of
5 reductions, as follows:

- 6 • Lowering our requested ROE from 11.0% to 10.5%: \$(13) million
- 7 • Reducing our requested incentive costs to reflect the Commission's treatment in
8 UE 197: \$(10) million

9 **Q. In addition to approving PGE's proposed 2011 revenue requirement, what additional**
10 **requests does PGE have of the Commission in this case?**

11 A. PGE requests that the Commission provide several accounting orders that would help
12 temper volatility of costs and customer prices in several areas:

- 13 • Provide an accounting order that allows PGE to establish a regulatory balancing
14 account to track differences between actual major storm damage costs and an
15 accrual (or estimate) of storm damage costs. We propose that an initial estimate
16 of storm damage accrual be set at \$3.5 million for 2011. PGE Exhibit 1000
17 describes the current availability of storm damage insurance and PGE Exhibit 800
18 describes the basis for the accrual, the conditions under which actual major storm
19 damage costs will be charged to the proposed account, and the underlying basis
20 for making this request. We request that the proposed account accrue interest at
21 PGE's authorized rate of return until the Commission approves amortization of
22 the outstanding balance in a subsequent rate case. The Commission can review
23 the prudence of costs included in the balancing account during the rate case in
24 which PGE requests amortization.

- 1 • Provide an accounting order that allows PGE to establish a regulatory balancing
2 account to track differences between PGE’s estimated pension expense and the
3 actual pension expense recorded on PGE’s financial statements. The balancing
4 account for pension expense is a component of PGE’s proposed Automatic
5 Adjustment Clause (AAC) tariff for pension related costs, which includes a return
6 on contributions to the pension trust in excess of pension expense. We request
7 that the proposed account accrue interest at PGE’s authorized rate of return until
8 the Commission approves amortization of the outstanding balance in a subsequent
9 rate case. PGE Exhibit 500 explains the rationale for this request and further
10 describes how the balancing account and AAC will function. PGE Exhibit 1501
11 provides a copy of the proposed Schedule 141.
- 12 • Provide an accounting order that allows PGE to track differences between the
13 environmental mitigation and remediation costs as projected in this case for
14 certain projects and the corresponding actual costs. We request that the proposed
15 account accrue interest at PGE’s authorized rate of return until the Commission
16 approves amortization of the outstanding balance in a subsequent rate case. PGE
17 Exhibit 700 describes this request in further detail.
- 18 • Provide an accounting order that allows PGE to accrue long-term debt costs on
19 study costs of self-build options for IRP/RFP purposes. In addition, we request
20 that the Commission allow PGE to create a future regulatory asset if we select an
21 alternative project to a self-build option. Section II provides the rationale for this
22 request and further describes the proposed accounting for such costs.

- 1 • Provide an order that allows PGE to account for the costs of collateral
2 requirements related to power supply as net variable power costs (NVPC) for
3 ratemaking purposes. PGE Exhibit 1100 describes this proposal in greater detail.
- 4 • Provide an accounting order that allows PGE to smooth the impact of O&M costs
5 related to the Information Technology (IT) system replacement program (2020
6 Vision). This will allow PGE to spread the incremental development O&M over
7 the life of the project, including both the development period and the amortization
8 period and will significantly reduce the price impact of these costs as compared to
9 including them in test year forecasts as they are expected to be incurred. PGE
10 Exhibit 600 further describes the proposal and calculations.

11 ***Rate Increase Drivers***

12 **Q. Please discuss the impact of net variable power costs (NVPC) on PGE's overall request**
13 **in this case.**

14 A. PGE's initial forecast of NVPC for the 2011 test year is \$747.2 million, or \$40.3 per MWh
15 of retail cost of service 2011 calendar year load of 18.5 million MWh. PGE's final 2010
16 NVPC forecast used to set rates in UE 208 was \$784.1 million to serve 18.5 million MWh,
17 or \$42.1 per MWh of retail calendar year load. Thus, a decrease in unit NVPC is
18 responsible for a decrease in revenue requirement of \$32.6 million. The lower NVPC is
19 included in the total \$125.2 million base rate increase sought in this proceeding. NVPC are
20 further described in PGE Exhibit 400.

21 **Q. What other cost components are responsible for PGE's \$125.2 million request in this**
22 **proceeding?**

23 A. Table 1 below itemizes the major sources of PGE's \$125.2 million request in this
24 proceeding.

Table 1
(Sources of Net Rate Increase)

<u>Source:</u>	<u>Approximate Rate Impact</u>
Investment and related costs, including ROE increase	4.25%
Higher O&M costs, including the impact of negative load growth since UE 197	5.15%
Impact of NVPC	(2.0)%
Overall 2011 Rate Increase	7.4%

1 ***PGE Results if No Rate Increase is Authorized***

2 **Q. In the absence of a rate increase, what is PGE’s expected regulated ROE for 2011?**

3 A. As shown in column 1 of PGE Exhibit 301, without a rate increase we would expect PGE’s
4 ROE to be approximately 6.0% in 2011.

5 **Q. Does this level of ROE reflect the impact that Sentate Bill 408 (SB 408) would have on
6 PGE if this rate case were not filed?**

7 A. No. Absent this rate case, we would expect a significant customer refund under SB 408 due
8 to the use of rate making ratios based on prior Commission proceedings (See Docket Nos.
9 UE 197, UE 204, UE 208, and UE 209). The use of these ratios would result in presumed
10 “taxes collected” under SB 408 far in excess of PGE’s projected tax liability for 2011.
11 Under the current SB 408 methodology, this “double whammy” would further reduce PGE’s
12 earned ROE in 2011 to approximately 4.5%.

13 ***Structure of the Case***

14 **Q. Does PGE’s 2011 revenue requirement include the effect of any new generating
15 resources for 2011?**

16 A. Yes. This case includes the net revenue requirement of Biglow Canyon phase 3 in 2011.
17 We expect Biglow Canyon phase 3 to begin operation in spring 2010, with all 76 turbines in

1 the 175 MW capacity project in service by September 2010. PGE plans to file separately
2 under the Renewables Adjustment Clause (RAC) Schedule 122 to defer the net revenue
3 requirement impact of Biglow Canyon phase 3 during 2010. Section X discusses Biglow
4 Canyon phase 3 in further detail, including the net revenue requirement impact of \$29
5 million for 2011 or about 1.7%, which is a component of the overall increase of \$125.2
6 million sought in this case.

7 **Q. Does the rate case incorporate other capital investments recovered through means**
8 **other than base rates in the recent past?**

9 A. Yes. Our 2011 revenue requirement in this case also includes the costs and benefits of
10 PGE's AMI investment, which was previously reflected in docket UE 189. As a result,
11 Schedule 111, which collects the net AMI revenue requirement, will be set to zero in 2011.
12 Section III provides a summary of the status of the AMI project and supports the estimated
13 savings of \$16.5 million reflected in this case. In addition, this case includes PGE's
14 investment in the Selective Water Withdrawal (SWW) facility at the Pelton Round Butte
15 hydro project. The Commission recently approved a stipulation in a separate proceeding
16 related to this investment (UE 204, Order No. 10-020) and rates went into effect February 1,
17 2010 through Schedule 121. PGE will use Schedule 121 to collect the Commission-
18 approved revenue requirement through 2010. We will set Schedule 121 prices to zero in
19 2011 since we include those costs in our base rate proposal in this case.

20 **Q. Please summarize PGE's 2011 revenue requirement.**

21 A. Table 2 below summarizes PGE's 2011 revenue requirement by major category and
22 provides a comparison to regulated utility actual results from 2008. We also list the PGE
23 testimony that addresses the specific cost categories.

Table 2
(Revenue Requirement Summary in \$000s)

	2008	2011		
<u>Rev Req Category</u>	<u>Actuals</u>	<u>Test Year</u>	<u>Exhibit</u>	<u>No.</u>
Sales to Consumers	\$1,541,583	\$1,810,997	Rev Req	300
Other Revenue	23,181	20,961	Rev Req	399
NVPC	662,284	747,192	Power Costs	400
Production O&M	89,235	123,316	Fixed Prod	700
Transmission O&M	10,757	12,621	T&D	800
Distribution O&M	69,642	84,075	T&D	800
Customer Service	68,660	71,044	Cust Svc	900
A&G			Corp	600,
	124,335	126,207	Support/IT	1000
Depr. & Amort.	207,503	232,564	Rev Req	300
Other Taxes	83,410	100,645	Rev Req	300
Income Taxes	59,398	65,447	Rev Req	300
Operating Income	189,540	268,846	COC	1100
ROE	9.38%	10.50%	ROE	1200

1 **Q. Please describe Operating Income as used in Table 2 above?**

2 A. Operating Income consists of a return to the providers of capital to PGE, both equity and
 3 debt. The costs of obtaining capital are discussed in PGE Exhibits 1100 and 1200.

4 **Q. How did you develop the 2011 revenue requirement?**

5 A. We developed the 2011 revenue requirement based on PGE's 2010 budgets, and then
 6 escalated for inflation and known and measurable changes. PGE Exhibit 200 describes the
 7 steps taken to maximize organizational efficiency to mitigate the proposed rate increase, in
 8 addition to the management discretionary items previously described.

9 **Q. What escalation rates did you use to escalate the 2010 budget to 2011?**

10 A. We applied the following escalation rates to the 2010 budget:

- 11 • Union labor = 3.6% effective March 1
- 12 • Non-union labor = 3.9% effective April 15 for non-officers and May 1 for officers
- 13 • Outside services (CE 21, 26, 41, 49) = 1.4% effective January 1
- 14 • Direct materials (CE 31, 36) = 1.1% effective January 1
- 15 • Employee business expense (CE 61, 68) = 2.3% effective January 1

16 **Q. What is the source of these escalation rates?**

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1 A. For outside service, direct materials and employee business expense, we use escalation rates
2 from the Global Insights, U.S. Economic Outlook dated May 2009. Union wage escalation
3 is based on the forecast of compensation costs described in PGE Exhibit 500.

4 **Q. Did you adjust PGE’s 2011 revenue requirement to reflect previous rate making**
5 **decisions and other regulatory policies?**

6 A. Yes. We made several regulatory adjustments, listed in Table 3 below.

Table 3
(Regulatory Adjustments in \$Millions)

<u>Adjustment Item</u>	<u>O&M</u>	<u>Rate Base</u>
Retail Services	\$(0.1)	\$(0.3)
Charitable Contributions	\$(1.2)	
State & Federal Lobbying	\$(1.3)	
Memberships and Dues	\$(0.1)	
MDCP	\$(7.5)	
SERP	\$(1.6)	
<u>Image Advertising</u>	<u>\$(1.0)</u>	
Total Adjustments	\$(12.8)	\$(0.3)

7 **Q. Please explain these regulatory adjustments.**

8 A. There are seven regulatory adjustments:

- 9 • Retail services: removed \$0.1 million of O&M and \$0.3 million of rate base per
10 the SB 1149 unbundling rules;
- 11 • Charitable contributions: excluded the entire \$1.2 million from cost of service;
- 12 • State and federal lobbying: excluded the entire \$1.3 million from cost of service;
- 13 • Memberships and dues: removed \$0.1 million which reflects the rate making
14 treatment received in UE 197;
- 15 • Managers Deferred Compensation Plan (MDCP): removed the entire \$7.5 million
16 from cost of service;
- 17 • Supplemental Executive Retirement Plan (SERP): removed the entire \$1.6
18 million from cost of service;

- 1 • Corporate image advertising: removed the entire \$1.0 million from cost of
2 service.

3 **Q. What comparisons of test year costs do you make in the testimonies generally?**

4 A. We compare our forecast of 2011 test year costs to 2008 actual costs. We perform these
5 comparisons because 2008 was the last full year of actual cost information available. In
6 addition, 2009 projected costs reflect unique circumstances due to economic factors and do
7 not provide a reasonable base for comparing to 2011 costs. Nevertheless, we provide
8 forecast 2009 costs in exhibits and work papers.

II. Preliminary Study Costs for Self Build IRP Options

1 **Q. What costs does PGE incur to study or evaluate self build options related to the IRP?**

2 A. PGE incurs costs associated with investigation, survey, and permitting in order to establish
3 the feasibility of self-build projects and to establish cost estimates for such projects. The
4 preliminary study activities include:

- 5 1) Analysis of the site and technology, including fueling, transmission and water
6 feasibility studies;
- 7 2) Securing land agreements;
- 8 3) An assessment of environmental site considerations and permitting feasibility to
9 obtain relevant state and federal permits; and
- 10 4) Preparation and filing of required documents for permitting.

11 **Q. What is the current accounting treatment of such costs?**

12 A. PGE currently records such costs in deferred accounts (FERC 183) on the balance sheet. If
13 PGE selects its self build option from a Request for Proposal (RFP) and the project has
14 received corporate approvals, we transfer the costs to Construction Work in Progress
15 (CWIP, FERC 107) and accrue Allowance for Funds Used During Construction (AFDC).
16 All of these costs are capitalized into the overall capital costs of building/acquiring the
17 project and are recovered over the estimated useful life of the facility. However, if PGE
18 selects an alternative resource bid into an RFP, the study costs initially recorded to the
19 balance sheet are written off to O&M.

20 **Q. How does PGE recover financing costs associated with self build study costs prior to
21 having an approved project?**

22 A. Historically we have not recovered such financing costs since the costs do not accrue AFDC,
23 nor are we otherwise compensated for these costs.

24 **Q. Does PGE development of a self build option benefit customers?**

1 A. Yes, the development of a self build option benefits customers by providing an alternative to
2 the bids of external parties.

3 **Q. Do alternative bidders in an RFP recover their costs to develop bids?**

4 A. Yes, over the long-term they must recover the costs of developing their losing bids,
5 otherwise they would not remain in business. While alternative bidders in an RFP may also
6 not be selected and hence may not recover the costs of developing a bid for a particular RFP,
7 they must recover these costs through subsequent winning bids, otherwise they would not
8 have a sustainable business. PGE seeks treatment on an equal footing with other going
9 concerns that may bid in an RFP.

10 **Q. Can't a "normalized" level of self build study costs be determined and included in your**
11 **rate request?**

12 A. No. The costs of developing a self build option are not easily forecast since they are
13 dependent on the type of resource being developed (coal, gas, wind, etc.), as well as the size
14 and operating characteristics of the potential facility. Further, PGE develops self build
15 options in conjunction with RFPs for major resources, the timing or frequency of which
16 cannot be readily predicted. Finally, such an estimate would require that we establish the
17 probability of not selecting our self-build option, which is not reasonable.

18 **Q. Is there a better regulatory response to these costs?**

19 A. Yes. PGE should be allowed to accrue financing costs associated with all self build study
20 costs from the time incurred, rather than just when a project has obtained internal approvals.
21 Historically, our investors have not been compensated for this cost. Further, PGE should be
22 allowed to recover these costs if our self build option is not selected both as a matter of
23 fairness and to eliminate the appearance of incentives to self-select projects.

1 **Q. What accounting treatment does PGE propose for self build study costs?**

2 A. We propose to continue to record any self build study costs initially in FERC 183 as
3 prescribed by the relevant Code of Federal Regulations (CFRs). However, we request that
4 the Commission allow PGE to accrue long-term debt costs on the balance of costs in FERC
5 183 based on the Commission authorized long-term debt rate. If we select an alternative
6 project to our self build option, we propose that we transfer any incurred self build study
7 costs to a regulatory asset (FERC Account 182.2), with an amortization period over 5 years
8 on a straight-line basis.

9 **Q. For study costs transferred to FERC 182.2, when would amortization of such costs
10 begin?**

11 A. Amortization of amounts transferred to FERC account 182.2 would begin the following
12 general rate case upon approval for amortization granted by the Commission.

13 **Q. If PGE recovers self-build study costs, including accrued long-term debt costs, for
14 resources not ultimately selected, does this create a potential violation of ORS 757.355
15 (i.e., the used and useful standard)?**

16 A. Our request avoids this legal issue. We propose that any amounts transferred to FERC 182.2
17 exclude any previously accrued long-term debt costs and not be included in rate base in this
18 or subsequent rate cases. As a result, the regulatory asset would not earn a “return on” in
19 any fashion.

20 **Q. Does PGE’s accounting proposal result in a change in costs that have been included in
21 the 2011 test year revenue requirement?**

- 1 A. No. PGE's incurred self build study costs for resources supported in the current IRP are still
- 2 awaiting a determination from the Commission. We have not included a forecast of
- 3 regulatory asset amortization for 2011 associated with this proposal.

III. Advanced Metering Infrastructure (AMI) Costs and Savings

A. Overview of AMI

1 **Q. Please briefly describe the AMI system.**

2 A. PGE is installing a smart-metering system that enables the automated collection of meter
3 data via a fixed network. A complete AMI system consists of solid-state electronic meters;
4 a communication system, or network, to transmit the data; and a communication server or
5 computer system that receives and stores data from the meter, and as a two-way system,
6 sends commands to the meter. This two-way capability enables the utility to send
7 commands and updates to the meter or control devices at the customers' premises as well as
8 receive signals regarding the meter's operating condition.

9 **Q. Was PGE's AMI proposal resolved in a specific OPUC Docket?**

10 A. Yes. In Docket No. UE 189, PGE, the OPUC Staff, the Community Action Partnership of
11 Oregon (CAPO), the Oregon Department of Energy (ODOE), and Northwest Natural
12 (NWN) reached a joint stipulation to adopt PGE's proposed system, which was then
13 approved by Commission Order No. 08-245. This order also included a Conditions
14 Document (Appendix A, pages 10-21) that specified certain commitments that PGE would
15 fulfill to: implement customer and system benefits, coordinate with CAPO and NWN, and
16 provide status reports and plan updates.

17 **Q. How much will the system cost compared to your initial estimates and when will it be
18 completed?**

19 A. At the time of the Joint Stipulation, PGE estimated that the fully deployed system would
20 total approximately \$132.2 million in capital costs. Based on our most recent estimate, we
21 still believe this to be the amount that will close to plant by year end 2010, when the system
22 will be fully deployed.

1 **Q. Please summarize the types of benefits the system will provide.**

2 A. The system is expected to provide two types of benefits: operating benefits and customer
3 and system benefits. We describe them briefly as follows:

4 • Operating benefits – the benefits that PGE achieves from the system as installed.

5 The primary component of this is the workforce reduction achieved by
6 eliminating most meter reading positions and many field credit representatives.

7 • Customer and system benefits – the benefits to be derived from additional

8 programs that can take advantage of the technological platform and new

9 information that the AMI system provides. These programs involve additional

10 costs and will only be implemented if and when economical to do so. The

11 primary component of this is demand response.

B. Operating Benefits

12 **Q. How much does PGE currently estimate it will achieve in operating savings due to**
13 **AMI?**

14 A. Based on our most recent estimates, PGE believes we will achieve approximately \$16.5

15 million in operating benefits in 2011, the first year after full deployment. Table 4 below

16 provides a summary of the savings in 2011.

Table 4
(Summary of AMI Operating Benefits in 2011)

Category	\$000
127.5 FTE reduction (net of incremental FTEs)	10,293
Contractor reductions	207
Overtime reductions	410
Material and supplies	441
Fuel and maintenance	1,057
Late pay fees	2,000
Power costs from remote disconnects	1,126
Additional billings from lost revenue protection	1,614
Improved Meter Accuracy	524
Power price delta	327
Incremental IT (non-labor)	(553)
Incremental system costs	(533)
Incremental communication costs	(370)
Total Operating Benefit	16,544

1 **Q. Has PGE reflected these savings in its 2011 forecast?**

2 A. The first six items in Table 4 are included in the specific O&M and other revenue categories
3 by responsibility center and PGE ledger (see work papers to this Exhibit). The power cost
4 and most of the additional billing benefits have been incorporated in the test year through
5 PGE's load forecast. Three items are currently not reflected in the 2011 forecast. First, the
6 MWh associated with \$300,000 of the \$1.6 million attributable to lost revenue protection
7 have not yet been incorporated into the load forecast discussed in PGE Exhibit 1400. PGE
8 will include this increment in the load forecast update for this filing.

9 **Q. Were any other items not included in the load forecast?**

10 A. Yes. The second item not included in the 2011 forecast relates to improved meter accuracy.
11 PGE is currently evaluating the specific difference in kWh attributable to the change in
12 meters and we expect that review to be completed before the next load forecast update. At
13 that time, we can include the latest estimate into the test year forecast. We note that the
14 UE 189 estimate is still valid absent additional information.

15 **Q. What is the third item that was not included in the rate case filing?**

1 A. The third item is the power cost benefit associated with changing power prices. This
2 specifically refers to the fact that the dollar benefits that we expect to achieve for the remote
3 connect/disconnect function is directly related to both the MWh savings and the price for
4 power that we avoid purchasing at the margin. In early 2008, at the time of the UE 189 Joint
5 Stipulation, power prices were estimated to be approximately \$66/MWh in 2011. Since
6 then, the recession has resulted in lower power prices and we currently estimate them to be
7 approximately \$51/MWh in 2011. Because power prices are beyond PGE's control, we note
8 this aspect of energy-related benefits as being temporarily unavailable but in the future, it is
9 fully achievable.

10 **Q. How does the current level of benefits compare to the UE 189 estimates?**

11 A. On the whole, PGE estimates that we will achieve or exceed the savings projected at the
12 time of the Joint Stipulation with the exception of two items. First, we expect to achieve the
13 estimated savings from power costs related to the remote connect/disconnect function,
14 except for the component related to power prices. As noted above, we expect this is a
15 temporary shortfall and not within PGE's control. The primary area in which we currently
16 believe that we will not achieve the projected benefits is from lost revenue protection (LRP
17 – also referred to as unaccounted for energy in UE 189).

18 **Q. Why do you believe you will not achieve these benefits?**

19 A. At the time we were evaluating AMI's impact in UE 189, we had minimal empirical
20 evidence on which to base an assumption regarding the improvement in MWhs captured
21 through LRP (determined as a percent of total load). A couple of studies indicated that a
22 wide range of LRP benefits was possible but PGE did not have a rigorous basis for choosing
23 the benefit level. In order to be conservative, PGE assumed that AMI would increase LRP
24 savings from 0.10% of total load to 0.25%. In settlement discussions, Staff indicated a

1 preference for the LRP impact to be increased from 0.10% to 0.30% of load. The combined
2 impacts were calculated at that time as an estimated benefit of \$3.6 million in 2011 based on
3 55.2 thousand MWh savings at a \$65.74/MWh price (i.e., assumed to be a power cost
4 savings based on 18.7 million MWh load with 98% ramp-up).

5 **Q. What is the basis for the benefit you are attributing to AMI?**

6 A. Based on our experience to date, PGE currently believes that this level of MWh benefits is
7 not realistic for two reasons. First, the baseline level of LRP assumed as the status quo in
8 UE 189 was also based on limited external studies and was too low. More recent evaluation
9 by PGE indicates our existing efforts are much more effective and efficient so that we
10 currently estimate the baseline to be approximately 31.9 thousand MWh rather than 18.4
11 thousand MWh. The second reason is that the LRP benefit we believe is achievable with
12 AMI is approximately 47.0 thousand MWh, which equals 0.24% of retail load. This results
13 in an AMI benefit of 15.1 thousand MWh, of which 12.3 thousand MWh are reflected in
14 current load forecast and 2.8 thousand MWh will be reflected in the load forecast update.

15 **Q. Is LRP really a power cost benefit?**

16 A. No. It represents an increase in discretely billable energy to specified customers offset by a
17 reduced line-loss factor, which keeps power costs constant. This means that the same
18 amount of power costs will be spread over a higher total load so that all customers will not
19 have to pay for the extra energy otherwise attributable to specific customers. Consequently,
20 the incremental LRP benefit totals \$1.6 million because we multiply the 15.1 thousand
21 MWh benefit times the weighted average retail rate (less the customer charge component)
22 for Schedules 7 and 32.

23 **Q. Will PGE re-evaluate the LRP benefit in the future?**

1 A. Yes. Our estimate is based on more current expectations compared to the estimate derived
2 two years ago. After we complete AMI deployment and have the advantage of evaluating
3 the LRP benefit from actual experience, we will update our load forecast with the benefits as
4 actually achieved.

5 **Q. Are there any other benefits that you can associate with AMI?**

6 A. Yes. PGE has also been awarded \$3.5 million in business energy tax credits (BETCs) for
7 reduced energy costs due to the elimination of meter reading vehicles and associated fuel
8 consumption.

9 **Q. How economical is AMI, based on the current level of estimated benefits?**

10 A. If we assume the forecasted level of 2011 benefits is extended forward at the same rate of
11 increase as calculated in the joint stipulation work papers, the net present value (NPV)
12 benefit of AMI is approximately \$21.4 million over the 20-year life of the project.¹

13 **Q. Is this a reasonable assumption?**

14 A. Yes, we believe so. First, most of the benefits are from workforce reductions that PGE has
15 incorporated in its forecast because we fully expect to realize them in 2011. Second, any
16 additional benefits derived from AMI will enhance the \$21.4 million NPV.

17 **Q. To what additional benefits are you referring?**

18 A. Achieving LRP benefits beyond the current assumption is a possibility, after we have
19 historical data to review. More significantly, however, the customer and system benefits
20 provide a significant source of additional benefits from AMI, particularly demand response.

C. Customer and System Benefits

21 **Q. What types of additional programs are envisioned as customer and system benefits?**

¹ The BETCs are included in the NPV calculation only for the five years to which they apply and correspond to 2011 in the same manner as incorporated in PGE's test year revenue requirement.

1 A. Customer and system benefits consist of the following:

- 2 • Demand response, including critical peak pricing (CPP)
- 3 • Distribution asset utilization, including:
 - 4 ○ Avoided service transformer failures
 - 5 ○ Proper transformer sizing
 - 6 ○ Early notification, to permitting agencies, of energy consumption exceeding
 - 7 customers' constructed electrical capacity (i.e., actual load exceeding safety
 - 8 margins at the customer's premises).
 - 9 ○ Delayed feeder conductor work
- 10 • Information driven energy savings (IDES)
- 11 • Outage management, including:
 - 12 ○ Avoided trouble calls
 - 13 ○ Faster one-premises outage response
 - 14 ○ Improved storm management
 - 15 ○ Faster fault location identification

16 **Q. What is the ultimate significance of the customer and system benefits?**

17 A. As noted above, AMI provides two types of benefits. Operating benefits are derived from
18 the system as installed and tend to be available first in the form of reduced O&M costs.
19 Customer and system benefits are informational savings that tend to come later and include
20 the use of the smart meter infrastructure through either the communications capability
21 and/or the interval data capability. Because the customer and system benefits have the
22 potential to be very significant, they were addressed in the UE 189 conditions document to
23 ensure their eventual pursuit.

1 **Q. Have you included any of the customer and system benefits in the 2011 test year**
2 **forecast?**

3 A. No. PGE does not expect to have any programs operating in 2011 at a level where material
4 benefits are realized.

IV. Other Revenue

1 **Q. What is PGE’s 2011 forecast of other revenue and how does it compare with prior**
2 **years?**

3 A. PGE forecasts 2011 other revenue of \$20.9 million. This compares to 2008 actual other
4 revenue of \$20.6 million

5 **Q. What are the sources of other revenue?**

6 A. The primary sources of other revenue are rent of electric property, transmission revenues,
7 joint-pole revenues, steam sale revenues, ancillary service revenues, and miscellaneous
8 charge revenues. PGE Exhibit 302 provides the sources and amounts of other revenue,
9 summarized in Table 5 below.

Table 5
(Other Revenue in \$Millions)

Other Revenue Item	2008 Actuals	2011 Forecast
Utility Property Rental	6,048	6,190
Intertie/Other Transmission	7,029	4,980
Late Payment Interest	801	2,800
Steam Sales	2,097	2,319
<u>Other Misc. Revenues</u>	<u>4,583</u>	<u>4,672</u>
Totals	20,558	20,961

10 **Q. Did you make any adjustments related to other revenue for the 2011 test year?**

11 A. Yes. We adjusted the 2011 forecast of transmission revenues received from Energy Service
12 Suppliers (ESSs). The adjusted amount reflects PGE’s current Open Access Transmission
13 Tariff (OATT) rate and the forecasted ESS activity for 2011. Due to reduced Direct Access
14 activity forecast for 2011, these revenues are approximately \$1.0 million less than 2008
15 actual revenues. Second, new Environmental Protection Agency (EPA) regulations are

1 under consideration that may prohibit the sale of fly-ash from our Boardman facility and
2 require that such ash be designated as a hazardous waste with corresponding disposal
3 requirements. To reflect this potential, we have removed approximately \$0.5 million from
4 2011 test year other revenue and we have added fly-ash disposal costs in production O&M.
5 Finally, we have added \$2.0 million in late payment revenue related to the AMI project and
6 reflected in Table 4 in the previous discussion of AMI benefits.

V. Depreciation

1 **Q. What is PGE's estimate for 2011 depreciation expense?**

2 A. We estimate \$216.3 million in depreciation expense for the 2011 test year. As previously
3 mentioned, this includes depreciation expense related to AMI and Biglow Canyon phase 3.
4 PGE Exhibit 303 summarizes the test year depreciation expense by plant type and provides a
5 comparison to actual 2008 and forecast 2009 depreciation amounts.

6 **Q. Is PGE proposing a new depreciation study as part of this rate case?**

7 A. Yes. PGE filed the study, docketed UM 1458, in November 2009. The study revised
8 estimates of lives, salvage value assumptions, and ultimately, depreciation rates by asset
9 group. PGE proposes that the new depreciation rates go into effect on January 1, 2011.

10 **Q. Please summarize the changes in depreciation method encompassed in the study filed**
11 **in UM 1458?**

12 A. PGE is proposing to extend the life span methodology, which was approved for all steam
13 and combustion plant assets in UM 1233, to all wind generation assets. The terminal date
14 for life span depreciation rate derivations will initially be set for the end of the final lease
15 extension. With an average life of 27 years, the assignment of the life span methodology
16 will initially have no impact on current depreciation rates for wind generation assets. PGE
17 also proposes that the Commission prescribe depreciation rates, consistent with the common
18 standard in the industry, rather than depreciation parameters. Finally, PGE is proposing to
19 update expected useful service lives and net salvage rates. A copy of the study filed in
20 UM 1458 is provided in our work papers.

21 **Q. Is your estimate of 2011 depreciation expense consistent with the results of the**
22 **depreciation study filed in UM 1458?**

1 A. Yes, except for one adjustment. We used the depreciation rates from the study to estimate
2 2011 depreciation expense, consistent with the forecast of plant in service amounts through
3 2011. However, we reduced the resulting 2011 depreciation expense forecast by \$10
4 million.

5 **Q. Why did you reduce the 2011 test year estimate of depreciation by \$10 million?**

6 A. Given PGE's experience in prior depreciation study proceedings, and based on preliminary
7 discussions with Staff, we believe that a likely outcome in the depreciation study docket will
8 result in modified depreciation parameters that will reduce 2011 depreciation expense.

9 **Q. Will PGE true-up estimated 2011 depreciation to reflect the final Commission Order in**
10 **UM 1458?**

11 A. Yes. PGE will update 2011 depreciation expense to reflect the Commission's decision in
12 UM 1458.

13 **Q. What impact does the new depreciation study have on 2011 depreciation expense?**

14 A. The proposed depreciation rates as filed in UM 1458, assuming Boardman's current life
15 assumption through 2040, increase depreciation expense in 2011 by \$8 million, relative to
16 the last approved depreciation study in UM 1233. The impact by asset class is provided in
17 PGE Exhibit 304.

18 **Q. What are the primary drivers of the \$8 million increase under the new study?**

19 A. The primary driver of the increase is the \$11 million related to specific studies of likely
20 hydro decommissioning costs, performed for all of PGE's owned hydro resources. Other
21 changes are largely offsetting, with lengthened asset lives reducing annual depreciation
22 expense while updates to net salvage assumptions increase annual depreciation expense.

23 **Q. What closure date has PGE assumed for Boardman in this filing?**

1 A. We use a 2040 end of life assumption for Boardman to develop the base revenue
2 requirement in this case.

3 **Q. On January 14, 2010, PGE indicated that it is pursuing a modified operating plan for**
4 **Boardman in the IRP process (Docket LC 48) that involves implementation of more**
5 **limited pollution control equipment and closure of the plant in 2020. Why have you**
6 **instead filed for rates consistent with a 2040 closure assumption?**

7 A. As indicated in the correspondence to the Commissioners dated January 14, 2010, the
8 stakeholders in the IRP process must work together to overcome barriers for PGE's plan to
9 be feasible. Given the uncertain outcome of this matter, we believe the best assumption,
10 under current conditions, is to maintain the current 2040 end of life date for proposed rates
11 at this time.

12 **Q. What if the Commission decides to implement either PGE's proposed 2020 plan, or an**
13 **alternative shut-down plan such as 2014 closure?**

14 A. To preserve the Commission's flexibility and to allow PGE to reflect in prices the impact of
15 a Commission decision to shorten the life of Boardman (relative to the current 2040
16 assumption), we have filed a Boardman Depreciation Revenue Requirement tariff (Schedule
17 145) in this proceeding. The purpose of the tariff is to allow the Commission to authorize
18 changes in prices to reflect the incremental revenue requirement impact of a shortened
19 Boardman operating life. Base prices will reflect the revenue requirement based on a 2040
20 end of life of Boardman. PGE will collect the net effect of Commission-ordered changes to
21 this life assumption through Schedule 145 upon approval by the Commission. A copy of
22 Schedule 145 is included in PGE Exhibit 1501.

1 **Q. Can you provide an estimate of the additional revenue requirement that would be**
2 **collected through Schedule 145 if the Commission approved either a 2014 or 2020**
3 **closure date for Boardman?**

4 A. Yes. If the change were effective January 1, 2011, and based on the un-depreciated
5 Boardman investment in this case, the additional 2011 revenue requirement collected
6 through Schedule 145 would be approximately \$53 million (a 2011 rate impact of about 3%)
7 under the 2014 shut-down scenario and \$14 million (a 2011 rate impact of about 0.8%)
8 under the 2020 plan. However, in the event of a Commission determination that the
9 operating life of Boardman be reduced from 2040, we would seek to update the estimate of
10 Boardman decommissioning costs to reflect a site specific study of Boardman prior to
11 implementing Schedule 145.

12 **Q. Are there other costs associated with shutting down Boardman?**

13 A. Yes. PGE would need to replace the energy generated from Boardman with new purchase
14 power agreements or additional generating resources. The estimated rate impacts noted
15 above for proposed Schedule 145 under a 2014 or 2020 closure scenario do not contain any
16 of these costs.

17 **Q. What pollution control equipment for Boardman do you forecast in this rate case?**

18 A. PGE will install low nitrogen oxide burners² (NOx) at the Boardman facility during the
19 maintenance outage in 2011. The equipment will be in service by June 2011, after the
20 maintenance outage scheduled for Boardman. The projected close to plant amount for this
21 equipment is \$29 million.

² This case was developed assuming that mercury control equipment would be installed in 2012, consistent with the 2040 operating life assumption. If the Commission adopted a 2020 closure, this project would occur in 2011 during the maintenance outage. Incorporating this into Schedule 145 would increase rates 0.1% relative to current rates if implemented 1/1/2011.

VI. Amortization

1 **Q. What is amortization?**

2 A. Amortization, like depreciation, is a means to allocate the cost of an asset over its useful life,
3 but amortization relates to intangible assets, such as computer software and regulatory
4 assets. As with depreciation expense, the unamortized balance of assets generally appears in
5 rate base and earns a return at the allowed rate.

6 **Q. Please summarize PGE's 2011 amortization expense.**

7 A. PGE Exhibit 305 details the total 2011 amortization expense of \$16.3 million, which we
8 summarize in Table 6 below.

Table 6
(Amortization in \$millions)

<u>Amortization Item</u>	<u>2008</u>	<u>2011</u>
	<u>Actuals</u>	<u>Test Year</u>
Software Amortization	10.2	11.8
Other Intangible Amortization	4.1	6.1
Trojan Decommissioning	4.6	3.5
Other Reg Debit Amortization	16.5	4.1
<u>Other Reg Credit Amortization</u>	<u>(4.3)</u>	<u>(9.2)</u>
Total Amortization	31.2	16.3

9 **Q. Please explain the amortization of software included in PGE's 2011 amortization**
10 **expense.**

11 A. Total software amortization is \$11.8 million, which represents the amortization of
12 capitalized software, recorded in FERC Account 303 and generally amortized over a 5-year
13 period.

14 **Q. Please describe Other Intangible amortization.**

15 A. Other Intangible amortization includes hydro relicensing amortization and miscellaneous
16 other intangible plant amortization. For hydro relicensing, this represents the recognition of
17 annual costs associated with non-construction projects that have closed to plant in service.

1 Generally, these costs are amortized over the life of the new license. PGE Exhibit 700
2 further describes these capital costs.

3 **Q. Why is Other Intangible amortization approximately \$1.8 million higher in the 2011**
4 **test year than either 2008 actual or forecast 2009 results?**

5 A. PGE forecasts the closure of approximately \$65 million of capitalized costs during 2010
6 upon receipt of a new FERC license for the Clackamas hydro projects. PGE amortizes these
7 costs over a 45-year period, which contributes \$1.6 million of annual amortization. PGE
8 Exhibit 700 provides further details on our efforts to obtain a new license for the Clackamas
9 projects.

10 **Q. Are any new intangible property related amortizations included in this filing relative to**
11 **UE 197?**

12 A. Yes. PGE expects the first phase of the 2020 Information Technology system replacement
13 program (2020 Vision) to close to plant in service at various dates in 2011. PGE Exhibit
14 600 discusses the program in detail. PGE proposes amortizing this software over a 10 year
15 period in the depreciation study. The Biglow Canyon phase 1 projects increase amortization
16 expense by \$1.1 million in 2011.

17 **Q. Please summarize the outcome from the last docket in which PGE changed its Trojan**
18 **Nuclear Decommissioning Trust (NDT) collection rate (UE 180).**

19 A. In Order No. 07-015, the Commission authorized: 1) the annual amount collected in rates to
20 be reduced from \$14.04 million to \$4.65 million, 2) that PGE may return to customers \$20
21 million from the Decommissioning Trust, and 3) PGE to continue collecting funds from
22 customers until Trojan decommissioning is complete.

1 **Q. Did PGE recommend any changes in the amount to be collected from customers in its**
2 **most recent general rate case (UE 197)?**

3 A. No. We performed an analysis of the annual accrual, updated for the latest trust balances,
4 expected rate of return on trust assets, cost estimates, and other parameters. This analysis
5 indicated that no change in the UE 180 approved accrual of \$4.65 million was required.

6 **Q. Does PGE recommend any changes in the amount to be collected from customers in**
7 **this proceeding?**

8 A. Yes. We recently updated the analysis described above, and recommend that a reduction to
9 the UE 197 approved accrual be made. Based on this analysis and the considerable
10 uncertainty associated with the spent fuel at the Trojan site, PGE proposes a lower annual
11 accrual rate of \$3.5 million, a \$1.15 million reduction.

12 **Q. Please elaborate on the uncertainty.**

13 A. Costs associated with the spent fuel at the Trojan site are the largest remaining
14 decommissioning costs. The future of the spent fuel has been uncertain for years as the
15 development and opening of the Yucca Mountain repository has been subject to continued
16 delays. Recently, the Obama Administration announced that it intends to terminate the
17 Yucca Mountain project and convened a blue-ribbon commission to develop and examine
18 alternatives. This commission is expected to provide a final report detailing its
19 recommendations within 24 months³. Given the additional delay in the U. S. Department of
20 Energy taking possession of Trojan's spent nuclear fuel, PGE believes it is appropriate to
21 support an accrual rate of \$3.5 million per year.

22 **Q. What decommissioning activity has been accomplished since UE 197?**

³ <http://www.energy.gov/news/8584.htm>

1 A. PGE has completed the demolition of the containment building and early demolition of
2 seven additional structures (Trojan Central Building, Maintenance Building, Solids Settling
3 Basin, South Warehouse, Fish Rearing facility, Environmental Lab Concrete Slab, and 33-ft
4 Meteorological Tower Concrete Slab). PGE has no further planned decommissioning
5 demolition work until after the spent nuclear fuel has been removed from the site.

6 **Q. Has the Colstrip Common Facilities amortization changed for 2011?**

7 A. No. We are continuing to amortize this asset as required under prior Commission order.

8 **Q. What is the Coyote Major Maintenance Accrual and Amortization?**

9 A. In UE 93 (OPUC Order No. 95-1216), the Commission approved an accrual and balancing
10 account treatment for Coyote's major maintenance costs. The major maintenance accrual is
11 based on a multiple-year forecast of major maintenance activities with an accrual estimate
12 designed to bring the balancing account to zero at the end of the multiple-year period. In
13 UE 180, the Commission approved updating the annual accrual to \$2.0 million.

14 **Q. Do you propose to change the Coyote major maintenance accrual for 2011?**

15 A. No. The previously approved \$2.0 million accrual was recently established and should
16 provide for recovery of major maintenance costs over a multiple-year period during which
17 major maintenance activities are expected to occur. We will re-evaluate the accrual level in
18 a future case. An estimate of the 2011 average balance in the balancing account of \$4.1
19 million is also included in rate base.

20 **Q. What major maintenance activities are expected at Coyote during 2011?**

21 A. In 2011 we will perform major inspections on the gas turbine, steam turbine and generator.
22 This work occurs every 48,000 hours of operation and is the most significant of the major
23 maintenance activities that take place at Coyote.

1 **Q. Has PGE included a forecast of property sale gains for the test year?**

2 A. No. We continue to support the use of the deferral mechanism for actual utility property
3 sale gains and losses originally approved in UE 115. Since actual gains/losses will be
4 deferred and refunded/collected through a supplemental tariff, we do not include any cost of
5 service reduction in the 2011 test year.

6 **Q. What are equity issuance fees?**

7 A. Equity issuance fees are the costs associated with issuing additional shares of common
8 equity. As discussed in PGE Exhibit 1100, PGE anticipates issuing \$300 million of equity
9 in 2011. PGE estimates the fees at 3.5% of the issue total, or \$10.5 million in 2011.
10 Further, equity issuance costs are recorded on the balance sheet as reductions in shareholder
11 equity under GAAP and are not expensed for either book or tax purposes.

12 **Q. What is PGE's proposed rate making treatment of equity issuance fees in this
13 proceeding?**

14 A. PGE proposes to treat the 2011 equity issuance fees as a regulatory asset for rate making
15 purposes and amortize them over a 10-year period beginning in 2011, consistent with the
16 treatment provided by the Commission in UE 197. Thus, we have added \$1.1 million in
17 equity issuance expense and we have added a regulatory asset to our rate base to reflect the
18 average unamortized balance in 2011. Finally, to recognize the non-tax deductible nature of
19 these fees, we have added a permanent book-tax difference to the derivation of income tax
20 expense in the test year.

21 **Q. Why is PGE proposing a multi-year recovery schedule for equity issuance fees in this
22 case?**

1 A. We propose this approach here to smooth the impact of the sizable equity issuance offering
2 expected in 2011 and to better match the recognition of costs with the expected benefits of
3 the capital projects that the equity will help finance.

4 **Q. Is PGE's 2009 equity issuance also reflected in this filing?**

5 A. Yes. We have continued the 10-year amortization of the 2009 equity issuance costs in this
6 case, along with the 2011 projected remaining average unamortized balance based on the
7 Commission's treatment of these costs in UE 197.

VII. Income Taxes, Taxes Other Than Income

A. Income Taxes

1 **Q. What is PGE’s 2011 estimate of income taxes?**

2 A. PGE’s 2011 test period income tax expense forecast is \$65.5 million. PGE Exhibit 306
3 details the test year calculations of income tax expense and provides a comparison to
4 previously authorized income tax assumptions. This compares to Commission-authorized
5 utility income tax expense of \$57.8 million based on approved rates. The increase in 2011
6 test year income tax expense compared to current rates primarily reflects increased taxable
7 income due to higher rate base, additional requested equity return, and a higher Oregon state
8 tax rate reflected in this case, offset partially by the effect of additional federal tax credits
9 related to Biglow Canyon phase 3.

10 **Q. What methodology did you use to establish estimated income tax expense for the 2011**
11 **test year?**

12 A. We use the “stand-alone” method to determine the test year income tax expense. This
13 method uses as inputs only those costs and revenues included in our requested test year
14 revenue requirement to determine the income tax expense for the test year. The
15 Commission has traditionally used this approach to determine the income tax expense in test
16 year rate making.

17 **Q. Does SB 408 (or OAR 860-022-0041) impact your estimate of income taxes for this**
18 **case?**

19 A. No. SB 408 requires an annual true-up between taxes collected and taxes paid, as those
20 terms are defined in the statute and OAR 860-022-0041. SB 408 itself does not require that
21 test year rate making assumptions about income taxes be changed. For PGE in particular, it

1 does not make sense to attempt to derive test year income tax expense using anything other
2 than the stand-alone approach because PGE's non-utility activity is minimal.

3 In order to implement SB 408, certain ratios must be established based on rate case
4 results to derive taxes collected for purposes of SB 408.

5 **Q. Have you calculated the updated ratios for SB 408 reflecting PGE's proposed revenue**
6 **requirement in this case?**

7 A. Yes. The updated net to gross ratio and effective tax rate to be used for SB 408 purposes in
8 2011 are shown in our work papers.

9 **Q. What income taxes does PGE pay?**

10 A. PGE pays income taxes to the federal government, States of Oregon and Montana, and to
11 local government entities such as Multnomah County.

12 **Q. What are the marginal tax rates for PGE?**

13 A. The federal marginal tax rate is 35.00%, the State of Oregon marginal tax rate is 7.60%, and
14 the State of Montana marginal tax rate is 6.75%. The State of Oregon tax rate has increased
15 from 6.60% to 7.60% as a result of legislation passed in 2009, and approved by voters in a
16 January 2010 ballot referendum.

17 **Q. What is PGE's state composite tax rate for this filing?**

18 A. PGE's composite state tax rate is 6.24%. The rate is a function of the marginal state tax
19 rates and the respective allocation factors of taxable income to different state jurisdictions.

20 **Q. Is the state composite rate different than it was in UE 197?**

21 A. Yes. In UE 197, the state composite tax rate was 5.12%. In this proceeding, we have
22 adjusted the figure upward to 6.24% to reflect the higher state tax rate in Oregon, as well as

1 adjustments to the allocation of taxable income between Oregon, Washington, and Montana
2 that reflect recent actual results.

3 **Q. What is PGE’s total composite tax rate for this filing?**

4 A. PGE’s total composite tax rate for this filing is 39.06%. It is the sum of the federal marginal
5 tax rate and the state composite tax rate, less the effect of their interaction, or:

6
$$35.00\% + 6.24\% - (35.00\% * 6.24\%) = 39.06\%$$

7 **Q. Why did you exclude tax rates from local jurisdictions from the calculation of the**
8 **composite tax rate?**

9 A. PGE collects Multnomah County Business income taxes through a supplemental tariff to
10 comply with OAR 860-022-0045 and to act as the SB 408 automatic adjustment clause for
11 local income taxes. As such, we do not include an estimate of the costs as part of our
12 revenue requirement in this proceeding.

13 **Q. Did you include state and federal tax credits in your estimate of income tax expense for**
14 **2011?**

15 A. Yes. We included \$3.2 million of state Business Energy Tax Credit (BETC), \$0.5 million of
16 non-Independent Spent Fuel Storage Installation (ISFSI) state pollution control tax credits,
17 and \$31.1 million of federal NEPA credits in the estimate of 2011 test year income tax
18 expense. Both the BETC state tax credits and the federal NEPA credits are earned from
19 PGE’s Biglow Canyon wind projects. As previously mentioned, this filing includes Biglow
20 Canyon phase 3 costs and benefits, including \$11.1 million of federal NEPA credits.

21 **Q. Why did you exclude ISFSI state tax credits from the derivation of 2011 income tax**
22 **expense?**

1 A. ISFSI tax credit amortization is excluded because PGE separately defers ISFSI tax credits
2 pursuant to UM 1186. Since these credits will be refunded to customers separately, we
3 exclude their effects on cost of service in the 2011 test year.

4 **Q. What level of Biglow Canyon project related BETC credits are included in your 2011**
5 **test year forecast?**

6 A. We include \$2.2 million in BETC credits, all of which relate to phase 1 of the Biglow
7 Canyon project.

8 **Q. Did you include BETC credits related to Biglow Canyon phase 2 or 3 in your 2011 test**
9 **year forecast?**

10 A. No. The ODOE has recently issued new administrative rules governing the eligibility of
11 renewable energy projects to receive BETC credits. At this time, the interpretation and
12 application of the rules to Biglow Canyon phases 2 and 3 is uncertain. While PGE has
13 received preliminary certification for these BETC credits, we are uncertain if Biglow
14 Canyon phases 2 and 3 will be eligible for these credits. Therefore, we excluded \$4.4
15 million from the 2011 test year.

16 **Q. If it becomes evident during the rate case process that PGE will in fact receive BETC**
17 **credits for Biglow Canyon phases 2 and 3, will PGE incorporate them in the test year**
18 **forecast?**

19 A. Yes. If it becomes apparent that either Biglow Canyon phase 2, phase 3, or both will be
20 eligible for BETC credits, PGE will incorporate the credits into the 2011 test year.

B. Taxes Other Than Income & Fees

21 **Q. What is PGE's 2011 estimate of Taxes Other Than Income and Fees?**

1 A. As shown in PGE Exhibit 307, total Taxes Other Than Income are \$100.6 million. This
2 compares to 2008 actual costs of \$83.4 million. The individual sources of increased costs
3 from the 2008 actuals to the 2011 test year are:

- 4 • Franchise Fees: from \$36.2 million to \$45.6 million;
- 5 • Payroll Taxes: from \$12.0 million to \$11.9 million;
- 6 • Property Taxes: from \$33.8 million to \$41.7 million; and
- 7 • Other miscellaneous fees: from \$1.5 million to \$1.4 million.

8 ***Franchise Fees***

9 **Q. How did PGE estimate franchise fees?**

10 A. We evaluated the expected level of franchise fees based on estimated 2011 gross revenue in
11 jurisdictions charging franchise fees and applied a 3.5% rate to those gross revenues. Based
12 on OAR 860-022-0040, cities may charge up to 3.5% of gross revenue that will be included
13 in PGE's revenue requirement and charged to all customers. Assessments up to 5.0% of
14 gross revenue are allowed, but the incremental fees above 3.5% are charged to customers
15 through a separate charge on the bill payable only by customers in the assessing jurisdiction.

16 **Q. Are franchise fees included in PGE's net to gross factor for calculating revenue**
17 **requirement?**

18 A. Yes. Consistent with the unbundling requirements of OAR 860-038-0200, we separately
19 itemize the impact of our incremental revenue needs on franchise fees in order to directly
20 assign all franchise fees to the Distribution function. The franchise fee rate used to
21 determine this revenue-sensitive cost is 2.517%, nearly identical to the rate of 2.514%
22 authorized in UE 197.

23 **Q. Why have franchise fees increased between current rates and the 2011 test year?**

1 A. Franchise fees have increased due to the impact of PGE's requested increase in this
2 proceeding.

3 ***Payroll Taxes***

4 **Q. What are payroll taxes?**

5 A. Payroll taxes represent local, state, and federal assessments on wages and salaries. The
6 federal components include FICA (Social Security), Medicare, and Unemployment. The
7 Oregon components include Worker's Compensation and Unemployment and there is a
8 local withholding for Tri-Met.

9 **Q. How does PGE estimate payroll taxes?**

10 A. PGE estimates payroll taxes by applying a 10.0% payroll tax rate to total wages and salaries.
11 We allocate a portion of payroll tax cost to capital consistent with the allocation of overall
12 capitalized wages and salaries.

13 **Q. Why are payroll taxes flat between 2008 actuals and the 2011 test year?**

14 A. Payroll taxes are essentially flat between 2008 actuals and the 2011 test year due to the low
15 wage/salary growth between those years described in PGE Exhibit 500 as well as the AMI
16 related FTE reductions.

17 ***Property Taxes***

18 **Q. Please describe PGE's obligation to pay property taxes?**

19 A. PGE holds property in three states: Oregon, Washington (KB Pipeline for gas used at
20 Beaver), and Montana (Colstrip and related transmission). As a result, PGE pays property
21 taxes in each of those jurisdictions. Each state uses its own method to determine the
22 property tax obligation.

23 **Q. How does PGE estimate property taxes?**

1 A. PGE’s estimates property taxes in each state using a highly involved process that reflects the
2 various methodologies employed by the assessing jurisdictions. The complicated nature of
3 the calculation does not lend itself well to using simplified methods, such as a CPI factor,
4 because there are so many factors requiring consideration.

5 **Q. Please explain further.**

6 A. PGE uses a unit approach because our properties are so thoroughly integrated that the
7 summation of valuing each individual property would not equal the entire utility. PGE uses
8 three indicators of value in evaluating utility valuation. In addition, jurisdictions are not
9 required to use historical valuation methodologies, but in the end, the taxing jurisdictions
10 make the final determination.

11 ***1. Calculation Methods to Estimate Property Tax***

12 **Q. What is the first method PGE uses to value utility property?**

13 A. PGE uses the Cost Approach. Value is derived using the regulatory calculation for rate base
14 with adjustments, as follows:

15 Plant in Service
16 + Construction Work in Progress
17 + Materials and Supplies
18 + Future Use
19 + Contributions in Aid of Construction (CIAC)
20 - Accumulated Depreciation/Amortization
21 = Net Value

22 CIAC is traditionally subtracted from plant in service to derive rate base. However, when
23 calculating property taxes, any contribution made by customers for bringing electrical
24 service to their property is taxable and therefore an addition to the calculation of plant in
25 service.

26 **Q. Are there other adjustments?**

1 A. Yes. The Trojan switchyard is still in use and therefore taxable, despite the fact that PGE's
2 Trojan assets were written off previously for book purposes. In addition, to be in
3 compliance with SFAS No. 143 (Asset Retirement Obligations), any assets included in plant
4 in service or accumulated depreciation for asset retirement obligations are excluded from tax
5 assessment. Lastly, PGE is required to pay reservation fees for wind turbines not yet
6 delivered. All advance payments or deposits for equipment not yet received are excluded
7 from tax assessment.

8 **Q. What is the second method used by PGE to calculate property tax?**

9 A. The second method is the Income Approach. This approach values the utility by the
10 amount of income PGE earns. A prospective buyer would look at the capitalization of the
11 future income stream (cash flow) that PGE could produce via its utility property. The value
12 is calculated as: net operating income divided by the capitalization rate less growth. Net
13 operating income includes the probable future average annual net operating income from
14 properties that exist on the assessment date (usually January 1 of any year at 1:00 a.m.).

15 **Q. How is the capitalization rate determined?**

16 A. Cost of capital is the basis of the capitalization rate. In Oregon, PGE's capitalization rate is
17 9.1% percent and Montana is 7.5% percent for direct capitalization of net operating income.
18 A high capitalization rate would reflect a lower valued property.

19 **Q. What is the third method used by PGE to calculate property tax?**

20 A. The third method is the Sales Comparison approach. This method compares similar
21 properties that have sold recently. Very similar to the market pricing of residential homes –
22 the recent home sales in a neighborhood provide an indicator of the value of residential
23 properties. This approach is somewhat difficult to estimate due to limited sales activity in

1 the utility industry. In place of this, tax authorities estimate value by examining the market
2 value of stock and debt. This approach is also difficult to calculate because of the
3 fluctuating nature of stock prices.

4 **2. *Correlation and Allocation***

5 **Q. Once these three methods are used to arrive at a valuation, how is property tax**
6 **estimated for each state?**

7 A. We begin by reviewing the three values and allocate by state. In Oregon, the three
8 methodologies are reviewed by the Department of Revenue and they determine a value
9 based on their judgment. Montana assigns a weight to each method to come up with system
10 value. The weighting process is very subjective. Since we have very little presence in
11 Washington, the three approaches to value are not used. Washington does not determine a
12 system value.

13 **Q. How is the allocation by state determined?**

14 A. System value is allocated to the state in which the property resides. Oregon starts with total
15 system value and then deducts the market value of ‘out of state’ property. Montana uses the
16 WSATA formula (Western States Association of Tax Administrators). The WSATA
17 allocation factor uses cost, operating capacity, and production megawatt hours by state to
18 estimate a percentage to allocate to Montana. Washington value is the historical cost less
19 depreciation of Washington’s assets.

20 **Q. Can PGE negotiate with any of the states?**

21 A. Yes and we do almost every year in Oregon and Montana. Because of the straight-forward
22 valuation methodology in Washington, historically we have not appealed in Washington.

1 Also, we have very little presence in Washington (17 miles of an 18 mile pipeline), the
2 amount of property taxes is small and it is not cost effective to appeal.

3 **Q. Has PGE benefited by appealing in Oregon and Montana?**

4 A. Yes. In Oregon we achieved a reduction in asset value of approximately \$139 million,
5 which results in a \$2 million reduction in property taxes. In Montana, PGE achieved a value
6 reduction of \$2.8 million. We generally have a difficult time in Montana. Since we have
7 limited property value in Montana as compared to Oregon, the costs to appeal in Montana
8 may not be worth the savings achieved.

9 **3. Estimate of 2011 Property Tax**

10 **Q. What is PGE's forecast for 2011 property taxes?**

11 A. PGE's forecast of 2011 property taxes is \$41.7 million, an increase from actual 2008
12 expense of 23%. Because property taxes are usually paid on a fiscal year basis, PGE must
13 forecast two years' of property tax assessment rates in coming up with the 2011 forecast of
14 property tax expense.

15 **Q. Please describe PGE's special tax treatment for Biglow Canyon Wind Farm and Port
16 Westward.**

17 A. PGE was able to negotiate a property tax reduction with Sherman County in exchange for
18 funding certain Sherman County programs. Sherman County agreed to offer PGE a
19 Strategic Investment Program (SIP) benefit which consisted of a partial property tax
20 exemption (also referred to as a "property tax holiday") in lieu of PGE funding Sherman
21 County programs such as the library and schools. The SIP benefit is the difference between
22 the property taxes paid to Sherman County plus the funding to the county programs, less
23 what the property taxes would have been.

1 **Q. Please describe PGE's special tax treatment related to Port Westward.**

2 A. The Enterprise Zone program serves local governments, such as Columbia County, that wish
3 to employ incentives and other assistance available to stimulate business investment and job
4 creation in their communities. The standard enterprise zone exemption abates taxes on new
5 property for three to five years. For Port Westward no property tax will be paid in
6 2008/2009 through 2012/2013.

7 **Q. What are the primary reasons why property taxes will increase from 2008 to 2011?**

8 A. The estimated property tax expense increase from \$33.8 million in 2008 to \$41.8 million in
9 2011 is primarily due to four factors: 1) \$4.6 million increase due to Biglow Canyon Wind
10 Farm becoming operational, 2) \$1 million increase is attributable to Montana property tax
11 (as our rate base increases so do our Montana property taxes), 3) \$1 million due to Selective
12 Water Withdrawal closing to plant in January 2010, and, 4) \$1.4 million for increases in tax
13 rates in Oregon, Washington, and Montana and other miscellaneous rate base increases. Our
14 work papers provide the basis for our 2011 property tax estimate and the change from actual
15 rates.

16 **Q. Was the 2011 estimate of Biglow Canyon phase 3 property tax expense developed**
17 **assuming the Strategic Investment Program (SIP) agreement?**

18 A. Yes. The SIP was approved in December 2007. As a result, we expect property tax expense
19 for 2011 for Biglow Canyon phase 3 of \$1.3 million versus estimated \$4.8 million without
20 the SIP.

21 **Q. Did you include the SIP-related costs for 2011 funding of programs in Sherman**
22 **County?**

1 A. Yes. We included \$635,000 of program-related cost associated with the SIP to fund
2 programs in Sherman County in 2011. These costs are recorded in A&G accounts, however,
3 rather than as property tax expense. Funded programs include School Renewable Energy
4 Program, Sherman Development League Library, Community Renewable Energy
5 Association, and Sherman County Renewable Energy Projects.

6 **Q. Does your 2011 forecast of property tax expense assume a property tax holiday for**
7 **Port Westward?**

8 A. Yes, for 2011 we anticipate \$2.4 million property tax savings associated with the Port
9 Westward generating facility located within the Enterprise Zone.

VIII. Capital Expenditures

1 **Q. What are PGE’s total 2011 capital expenditures?**

2 A. As shown in PGE Exhibit 308 and summarized in Table 7 below, PGE forecasts \$364
3 million in total utility capital expenditures for 2011, compared with 2008 actual capital
4 expenditures of \$371 million.

Table 7
(Capital Expenditures in \$Millions)

Type	<u>2008 Actual</u>	<u>2011 Test Year</u>
Production	\$17.2	\$23.2
Transmission	5.1	4.6
Distribution	117.4	138.8
Intangible	7.4	5.1
General	<u>24.0</u>	<u>27.3</u>
Cap Ex – Operations	171.1	199.0
Strategic	<u>199.5</u>	<u>165.1</u>
Cap Ex – Total	\$370.6	\$364.1

5 **Q. How does PGE account for capital expenditures?**

6 A. As PGE spends capital for utility projects, we record it as CWIP, a non-rate base account.
7 Once the project is completed, PGE moves the capital expenditures (and associated AFDC)
8 from CWIP to plant in service accounts. Once moved to plant in-service accounts, the
9 project becomes part of PGE’s rate base with associated depreciation expense and property
10 tax expense recorded in the appropriate income statement accounts.

11 **Q. Are there any significant capital expenditures that you do not expect will close to plant**
12 **in service during 2011?**

13 A. Yes. We forecast capital expenditures for the Cascade Crossing transmission project that we
14 currently expect to close beyond the end of 2011. In addition, we forecast capital
15 expenditures for our proposed capacity and energy projects in the IRP that will also close
16 beyond the test year. Our work papers detail the capital expenditures in 2010 and 2011 that

1 are expected to close in 2011 (or prior) as well as those capital expenditures that are
2 expected to close after 2011.

IX. Rate Base

1 **Q. What is PGE’s 2011 average rate base and what does it include?**

2 A. The total 2011 average rate base is \$3,244 million. PGE Exhibit 309 provides the details of
3 the 2011 average rate base, which includes PGE’s investment in plant in service, net of
4 Accumulated Depreciation, Accumulated Deferred Taxes, and Accumulated Investment Tax
5 Credits (ITC). In addition, the average rate base includes Fuel and Materials Inventory,
6 Miscellaneous Deferred Debits and Credits, and Working Cash.

7 **Q. How does PGE’s 2011 rate base compare to rate base amounts approved (or pending)**
8 **in prior dockets?**

9 A. PGE Exhibit 310 shows that the average rate base approved/pending in prior dockets is
10 \$2,706 million. PGE’s average rate base increases by \$538 million to \$3,244 million, as a
11 result of several factors. The major factors include:

- 12 • The completion of Biglow Canyon phase 3, increasing rate base by \$379 million;
- 13 • The receipt of a new FERC license to operate the Clackamas hydro projects,
14 increasing rate base by \$64 million;
- 15 • The completion in 2010 and inclusion in 2011 rate base of AMI increases average
16 rate base by \$64 million;
- 17 • The completion of low NOx burners at Boardman, increasing average rate base by
18 \$14 million;
- 19 • An efficiency upgrade of the Coyote facility, increasing average rate base by \$17
20 million;
- 21 • Closure of certain Information Technology (IT) system replacement program
22 conform with increasing rate base by \$15 million;

- 1 • New regulatory debits for equity issuance fees and pension financing costs in
2 2011, increasing average rate base by \$21 million;
- 3 • Reduced working capital needs lowering average rate base by \$11 million; and
- 4 • Miscellaneous other changes, including depreciation of prior vintage plant in
5 service, capital additions, deferred tax changes, and other changes decreasing rate
6 base by \$24 million.

7 **Q. How did you develop the estimate of plant in service for the 2011 test year?**

8 A. First, we estimated year-end 2009 embedded plant using actual results as of the end of the
9 third quarter with forecasted closings through year-end. Next, we evaluated 2010 and 2011
10 capital additions. Certain larger projects were closed based on a specific forecasted closing
11 date. For example, we forecast the Clackamas relicensing project to close by December 31,
12 2010. Also, we expect the low NOx burners at Boardman and the Coyote turbine upgrade to
13 close in June 2011 and May 2011, respectively, corresponding to the end of the maintenance
14 outages at Boardman and Coyote.

15 However, we model most capital additions by evaluating CWIP balances using
16 historical experience. We then applied a forecast closing pattern to CWIP to develop plant
17 in service estimates from 2010 and 2011 capital additions. Our work papers detail the
18 development of 2011 plant in service from forecast embedded plant at year-end 2011.

19 **Q. Are there any new rate base items in 2011 relative to prior proceedings?**

20 A. Yes. We have two new deferred debit balances in the 2011 test year. The first is deferred
21 2011 equity issuance costs, which average \$10 million for the 2011 test year. The second is
22 incremental pension funding costs above the level of pension expense in 2011, which
23 average \$11 million for the 2011 test year.

1 **Q. Do you have any other observations regarding 2011 rate base?**

2 A. Yes. The overall growth in PGE's rate base relative to either authorized amounts in current
3 rates or forecasted year-end 2009 balances is the result of the specific investments described
4 above. PGE's capital additions related to operations are generally designed to maintain the
5 existing system and are at a rough steady-state with annual book depreciation.

6 **Q. Does PGE propose a new lead-lag study to update working cash in 2011?**

7 A. Yes. PGE completed a new lead-lag study, a summary of which is provided as PGE Exhibit
8 311, and the study results are provided in our workpapers. The result is a working cash
9 allowance figure of 3.90% for 2011 as compared to the 5.20% figure used in UE 197.

10 **Q. What is the working cash total added to rate base in this filing?**

11 A. Applying the 3.90% working cash factor to the total forecast operating expenses in 2011 of
12 \$1,563 million yields the working cash addition to rate base of \$61 million, which is shown
13 in PGE Exhibit 301.

14 **Q. Does the lead-lag study take into account the cost of collateral deposits described in
15 PGE Exhibit 1100?**

16 A. No. With regard to purchased power and fuel, the lead-lag study evaluates the lag between
17 delivery month of fuel or power and the payment of an invoice. It does not capture the
18 financing costs associated with movements in the value of an energy/fuel position prior to
19 the month of delivery, which is the basis of collateral requirements described in PGE Exhibit
20 1100.

X. Biglow Canyon phase 3

1 **Q. Please summarize the revenue requirement of PGE's Biglow Canyon phase 3**
2 **investment.**

3 A. PGE is requesting recovery of approximately \$29.0 million of revenue requirement for the
4 2011 test year, which is a component of the overall revenue requirement provided in PGE
5 Exhibit 301. In a separate filing under the Renewables Adjustment Clause (RAC), PGE will
6 also request deferral of Biglow Canyon phase 3's 2010 revenue requirement. These
7 amounts are net of the estimated value of the energy produced by Biglow Canyon phase 3.

A. Project Description

8 **Q. Please provide an overall description of the Biglow Canyon Wind Farm.**

9 A. Biglow Canyon is located in Sherman County, near the Columbia River in north-central
10 Oregon, and is being developed in three phases. Biglow Canyon phase 1 is complete,
11 consisting of 76 wind turbines, each with a capacity of 1.65 MW, for a total capacity of
12 approximately 125 MW. Biglow Canyon phase 1 has been operating since late 2007 (see
13 Docket No. UE 188). Biglow Canyon phase 2 is also complete, consisting of 65 wind
14 turbines, each with a capacity of 2.3 MW, for a total Biglow Canyon phase 2 capacity of
15 approximately 150 MW. Biglow Canyon phase 2 has been operating since mid-2009 (see
16 Docket No. UE 209).

17 We have begun construction of Biglow Canyon phase 3, putting in roads, foundations,
18 etc. Biglow Canyon phase 3 will consist of 76 turbines, each with a capacity of 2.3 MW, for
19 a total Biglow Canyon phase 3 capacity of approximately 175 MW. We expect to complete
20 Biglow Canyon phase 3 by the end of 2010. In total, the three phases of the Biglow Canyon
21 Wind Farm will have a capacity of approximately 450 MW.

1 ***I. Turbine Supply***

2 **Q. Who is supplying the turbines for Biglow Canyon phase 3?**

3 A. PGE is using the same model of turbines for Biglow Canyon phase 3 as were used for
4 Biglow Canyon phase 2. Siemens Wind Generation, Inc. (Siemens) is supplying the
5 turbines, pursuant to the Wind Turbine Generator and Tower Supply, Installation,
6 Commission and Warranty Agreement (Turbine Supply Agreement) between Siemens and
7 PGE.

8 **Q. How did PGE select the turbines for Biglow phases 2 and 3?**

9 A. PGE initiated an invitation to bid for Biglow phases 2 and 3 on March 8, 2007, and received
10 bids from several different manufacturers. We narrowed the list of bidders and began
11 negotiations with the remaining bidders. We determined that Siemens provided the best
12 solution for our requirements.

13 **Q. Why did PGE select Siemens?**

14 A. PGE selected Siemens based on a set of criteria (e.g., price, ability to meet PGE's timetable,
15 ability to meet turbine order quantity, etc.). Additionally, PGE wanted to acquire larger
16 turbines for phase 2 and/or 3 than the 1.65 MW turbines used for Biglow Canyon phase 1 in
17 order to realize the full capacity of the Biglow Canyon wind farm site.

18 **Q. What is the warranty period?**

19 A. Under the Turbine Supply Agreement, Siemens will perform warranty service for a period
20 of five years, which includes the initial warranty period of two years and a three-year
21 extension.

22 **Q. What did PGE pay for this three-year extension?**

1 A. The guaranteed availability and warranty extension of three years was at an incremental cost
2 of approximately \$8.8 million. During the invitation to bid process, PGE sought bids with
3 approximately a five-year warranty period. This will provide PGE a period of time when
4 only Biglow Canyon phase 1 will be out of the warranty period, allowing PGE to gain
5 experience in self-providing the services previously covered by warranty. This time period
6 is of greater importance due to the change in turbine vendors.

7 **2. *Transmission***

8 **Q. Is Biglow Canyon phase 3 in BPA's system control area?**

9 A. Yes. All three phases are in the BPA control area.

10 **Q. Will PGE's Large Generator Interconnection Agreement (LGIA) with the BPA be**
11 **sufficient for Biglow Canyon phase 3?**

12 A. Yes. On September 11, 2009, BPA issued an amendment increasing the LGIA from 400 to
13 450 megawatts.

14 **Q. Please describe Biglow's interconnection with the regional grid.**

15 A. To facilitate the interconnection of Biglow Canyon, BPA expanded its 500 kV John Day
16 substation, constructed a new 230 kV John Day substation, and built a new 230 kV
17 transmission line, including a six-mile portion from Biglow Canyon to John Day.

18 **Q. Will BPA provide transmission of power from Biglow to PGE's service territory?**

19 A. Yes. For Biglow Canyon phase 1, we redirected 150 MW of our Rocky Reach to Portland
20 rights under our point-to-point (PTP) transmission agreement with BPA. PGE has
21 redirected 300 MW of our John Day to Portland rights for Biglow Canyon phases 2 and 3.

22 **Q. Do PGE's payments for BPA transmission services change with this PTP redirection?**

1 A. Yes. BPA classifies approximately \$15 million of the interconnection costs discussed above
2 as network upgrades. PGE paid for the upgrades to BPA's network and BPA must repay the
3 \$15 million, plus interest. Pursuant to the LGIA, BPA will base the repayment credits on
4 MWs of installed capacity. With the addition of approximately 175 MW of capacity, PGE
5 will recover its investment more quickly. We have included an estimate of amortization as
6 well as the BPA credit associated with Biglow Canyon phase 3 in this proceeding.

B. Revenue Requirement

7 **Q. What is the overall impact of Biglow Canyon phase 3 on PGE's 2011 revenue**
8 **requirement?**

9 A. PGE currently forecasts Biglow Canyon phase 3's 2011 net revenue requirement to be
10 approximately \$29.0 million. The 2011 energy benefits, which are included in PGE's 2011
11 Net Variable Power Cost forecast, are approximately \$22.3 million. These benefits are net
12 of the costs to shape and integrate Biglow's variable energy output which are also included
13 in PGE's 2011 NVPC forecast in this filing. PGE Exhibit 312 summarizes the development
14 of Biglow Canyon phase 3's revenue requirement.

15 Biglow Canyon phase 3's pre-tax operating income is \$26.4 million. Depreciation is
16 \$18.7 million, O&M costs are \$3.9 million, property taxes are \$1.3 million⁴, revenue
17 sensitive costs total \$1.0 million, and net variable power cost benefits of \$22.3 million. The
18 result is an overall (net) revenue requirement of \$29.0 million.

19 **Q. How do you calculate the net energy benefits?**

⁴ Property taxes are calculated based on MW of nameplate capacity. For Biglow 3 this translates into approximately \$2.68 million on an annual basis (\$15,340 per MWh times 174.8 MW). Only half of this amount is included for the 2011 test year because the property tax year begins July 1, 2011 and ends June 30, 2012. PGE had zero property tax assessed for the period of July 1, 2010 through June 30, 2011 because there was no operating asset to assess as of January 1, 2010.

1 A. For purposes of the 2011 revenue requirement, we use the output from PGE’s power cost
2 forecasting model, MONET. These 2011 net energy benefits are included in PGE’s 2011
3 NVPC forecast in this filing. From the value of Biglow’s output, we then subtract the
4 associated regulation, imbalance, integration, reserve, and royalty costs. We describe these
5 costs in detail later in this section of our testimony.

6 **Q. Will the Energy Trust of Oregon (ETO) provide funding to cover the difference**
7 **between the cost of Biglow Canyon phase 3’s power output and the cost of the same**
8 **power output purchased at expected market prices?**

9 A. No. Senate Bill 838, The Renewable Energy Act, limits the ETO’s ability to fund new
10 renewable resources to projects of up to 20 megawatts. This differs from Biglow Canyon
11 phase 1, where an agreement was reached with the ETO prior to the passage of Senate Bill
12 838.

13 *I. O&M Costs*

14 **Q. Does the 2011 O&M forecast include the cost of a turbine maintenance agreement?**

15 A. Yes. The 2011 cost of the Service and Maintenance Agreement (Maintenance Agreement)
16 is the largest component of O&M for Biglow Canyon phase 3.

17 **Q. Is PGE proposing a major maintenance accrual for Biglow similar to that for Coyote**
18 **Springs?**

19 A. No. Biglow Canyon phase 3’s Maintenance Agreement has a more levelized annual cost,
20 eliminating the need for an accrual.

21 **Q. How many full-time equivalent (FTE) employees will work at Biglow?**

22 A. Currently, Biglow Canyon phases 1 and 2 have six FTEs. We expect Biglow Canyon phase
23 3 to add two FTEs, consisting of two full-time wind technicians.

1 **Q. How are royalty costs calculated?**

2 A. PGE pays royalties to Orion Energy, LLP (Orion) and the land owners at the Biglow
3 Canyon Wind Farm site on a \$/MWh basis. Royalties for 2011 are approximately \$2.40 per
4 MWh for Biglow Canyon phase 1, approximately \$3.29 per MWh for Biglow Canyon
5 phase 2, and approximately \$3.34 per MWh for Biglow Canyon phase 3.

6 **2. Wind Integration**

7 **Q. How must PGE manage the intermittent nature of the wind power generated by**
8 **Biglow?**

9 A. Conceptually, there are three distinct services that PGE must either purchase or self-provide:

10 1) Within-Hour Balancing, which consists of *regulating margin* (the moment-to-
11 moment adjustments in generation output) and *load following* (the larger step-changes in
12 generation over the course of the hour and during generator ramping);

13 2) Generation Imbalance, which covers the deviations in output between hourly
14 schedules and actual hourly output; and

15 3) Day-Ahead and Hour-Ahead Uncertainty, which covers the system optimization
16 costs on a day-ahead and hour-ahead basis.

17 **Q. Which of these services can be purchased from BPA?**

18 A. BPA charges PGE the Wind Integration - Within-Hour Balancing Service and Generation
19 Imbalance Service rates based upon the provisions in PGE's Large Generator
20 Interconnection Agreement. As a Generator Owner/Operator within the BPA Balancing
21 Authority Area, PGE is required to submit day-ahead and hour-ahead generation schedules
22 to BPA for Biglow Canyon. These estimated generation schedules are the basis for the
23 Generation Imbalance Service charges.

1 **Q. How have you modeled regulation, imbalance, and integration costs in the MONET**
2 **estimate of net variable power costs?**

3 A. PGE used its best estimate of the cost to purchase and self-provide these services during the
4 2011 test year. Our estimate is based on figures provided in regional discussions, the
5 knowledge of PGE's real time and structuring groups, and BPA's charges for the imbalance
6 and integration services. This is the same approach used for Biglow Canyon phases 1 and 2.

7 **Q. Do you incorporate the cost of operating reserves?**

8 A. Yes. Though not an itemized cost, PGE has updated the operating reserves calculation in
9 MONET to reflect the need to support Biglow Canyon phase 3.

10 **3. Taxes**

11 **Q. Are there tax credits associated with Biglow Canyon phase 3?**

12 A. Yes. We include Production Tax Credits (PTC) of \$11.1 million in the 2011 test year. These
13 credits are incorporated into PGE Exhibit 312 as 'Federal Tax Credits.'

14 **Q. What are the key features of the renewable energy tax credit?**

15 A. The Emergency Economic Stabilization Act (HR 1424) of 2008 extended the National
16 Energy Policy Act (NEPA) tax credits for renewable energy resources, including a one-year
17 extension of the PTC for wind resources and an eight-year extension of the ITC for solar
18 projects. In February 2009, the American Recovery and Reinvestment Act (Reinvestment
19 Act) further extended the PTCs for wind by three years, through December 31, 2012. The
20 Reinvestment Act also provides the option of claiming a 30% ITC instead of the PTCs.
21 Should a taxpayer claim the ITC, the Reinvestment Act allows for the ITC to be exchanged
22 for an equivalent grant from the Treasury Department.

1 **Q. Did PGE evaluate the Reinvestment Act to determine if any additional benefits are**
2 **available that would reduce Biglow Canyon phase 3's costs?**

3 A. Yes. As previously mentioned, the Reinvestment Act provides an option to select between
4 production tax credits, investment tax credits, or Treasury grants. Based on our review, the
5 PTCs result in the greatest value to our customers because the ITCs and Treasury grants
6 would be subject to IRS normalization requirements. As a result of these requirements,
7 shareholders (rather than customers) would benefit from the amortization of the ITC/grants,
8 thereby diminishing their value to customers. The revenue requirement provided in this
9 testimony includes PTCs for Biglow Canyon phase 3.

10 **Q. What value do the PTCs provide for customers?**

11 A. Tax credits based on Biglow's production will begin when the plant becomes operational
12 and will continue for 10 years. We estimate \$22/MWh in our 2011 revenue requirement. If
13 appropriate, we will incorporate any change to the PTCs in our final test year estimate in this
14 proceeding.

15 **Q. Will Biglow Canyon phase 3 receive Business BETC?**

16 A. Possibly. In November 2009, the Oregon Department of Energy (ODOE) issued temporary
17 rules regarding facilities that qualify for BETC credits that put into question whether or not
18 PGE will receive BETC credits for Biglow Canyon phase 3. As a result, PGE has excluded
19 them from the 2011 revenue requirement. If PGE receives clarification during this
20 proceeding, PGE will include the BETC credits in its forecasts.

21 **Q. Does Biglow Canyon phase 3's average rate base include unutilized tax credits?**

22 A. Yes, in the amount of \$11.1 million for 2011. PGE does not expect to have enough taxable
23 income to make use of the entirety of the tax credits associated with Biglow Canyon phase

1 3, so the deferred tax credits have been added to rate base. PGE expects to use these credits
2 in the future and will amortize them from rate base as they are used.

3 **Q. Does Biglow Canyon qualify for special property tax treatment?**

4 A. Yes. In November 2007, PGE, Sherman County, and the State of Oregon reached an
5 agreement that applies to up to 450 MW of the Biglow Canyon wind farm. In lieu of normal
6 property taxes, PGE pays taxes on the basis of installed megawatts at the project plus
7 specified additional contributions to county projects such as a library, community
8 college, etc.

9 **Q. Does PGE plan to update estimates of Biglow costs and benefits during this
10 proceeding?**

11 A. Yes, for a number of reasons. First, the value of the expected energy from the Biglow
12 project will change as the expected market price of electricity changes and/or as the project
13 begins generating. Second, as the project proceeds through the construction phase, PGE will
14 have better estimates of the total construction costs of the project. Third, if PGE confirms
15 that it will receive BETCs, we will update the 2011 revenue requirement accordingly. For
16 these reasons, we believe updating Biglow's expected revenue requirement is appropriate.

17 **Q. Has the Commission already issued orders to allow the development of the Biglow
18 Canyon wind farm?**

19 A. Yes. Commission Order No. 06-293 (UP 234) allowed PGE to grant a lien to Orion, the
20 original developer of the site, on certain substation property and allowed Orion the right to
21 repurchase certain assets from PGE, if PGE decides not to fully develop the project. Order
22 No. 06-419 (LC 33) allowed PGE to “seek inclusion of the acquisition of the Biglow Wind
23 Project in its rate base at cost, rather than in its revenue requirement at market price” (Order

1 at 1). Order No. 07-573 (UE 188) allowed PGE to recover its costs and earn a return on its
2 investment in Biglow Canyon 1. In Order No. 08-246 (LC 43) the Commission, though not
3 acknowledging the entirety of PGE’s 2007 Integrated Resource Plan, did find PGE’s
4 renewable resource actions reasonable, which includes the development of Biglow Canyon
5 phases 2 and 3. In Order No. 09-398 (UE 209), the Commission approved recovery of
6 PGE’s investment in Biglow Canyon phase 2.

XI. Unbundling

1 **Q. Have you unbundled the 2011 revenue requirement pursuant to OAR 860-038-0200?**

2 A. Yes. PGE Exhibit 313 summarizes the results of unbundling the integrated revenue
3 requirement, as required by OAR 860-038-0200, into the required functional areas or
4 revenue requirement categories. Table 8 below summarizes the unbundled revenue
5 requirement for 2011.

Table 8
(Unbundled Revenue Requirement - \$Millions)

Production	\$1,189.3
Transmission	36.5
Distribution	487.3
Metering	5.1
Billing	27.7
Other Consumer Services	59.7
Ancillary Services	5.3
<u>Public Purposes</u>	<u>Collected by separate tariff</u>
Total	\$1,811.0

6 The sum of the unbundled revenue requirement for these services equals the integrated
7 revenue requirement as presented in PGE Exhibit 301.

8 **Q. How did you develop the revenue requirement after unbundling costs and rate base?**

9 A. We used traditional revenue requirement methodology – recovery of cost plus a return on
10 rate base – to calculate the revenue requirement for each unbundled service in accordance
11 with OAR 860-038-0200(9)(d).

12 **Q. How did you unbundle PGE's 2011 expenses and other revenue?**

13 A. We unbundled expenses and other revenue by analyzing each ledger within those categories.
14 First, we determined which ledgers could be directly assigned to one of the functional
15 categories listed in Table 8 above. Second, we evaluated those ledgers that could not be
16 clearly assigned to determine a basis for allocation.

1 **Q. Were most of the expense and other revenue ledgers assigned or allocated?**

2 A. The majority of ledgers have a direct relationship with a single functional area and we
3 assigned these ledgers based on OAR 860-038-0200(9)(b)(A) through (E). The largest
4 category of allocated costs is A&G, which we allocated to the functional areas based on
5 labor dollars for those areas. Other costs, such as property taxes, payroll taxes, and income
6 taxes, relate to factors such as net plant, labor, net income, or total revenue. We allocated
7 these costs based on the respective share of those factors per functional area in accordance
8 with OAR 860-038-0200(9)(c)(B)(i) through (ii). For other expenses, such as depreciation
9 and amortization, we “functionalized in the same manner as the respective plant accounts” –
10 see OAR 860-038-0200(9)(c)(A).

11 **Q. Did you allocate any expense or other revenue to retail or non-utility?**

12 A. Yes, for retail and no for non-utility. First, we allocate costs to retail based on labor charges
13 to the ledgers assigned to retail. Second, while we forecast labor costs in non-utility,
14 “below-the-line” accounts, these ledgers already receive allocations for corporate
15 governance (i.e., A&G/Support costs) and service providers (i.e., facilities, IT, and
16 print/mail services). Therefore, unbundling A&G (or other support costs) to non-utility
17 ledgers would apply these costs twice.

18 **Q. How did you unbundle rate base?**

19 A. There are two categories of rate base that we evaluated for unbundling: 1) plant in service
20 with associated depreciation reserve, accumulated deferred taxes, and accumulated
21 investment tax credits; and 2) other rate base. For plant in service, we assigned most assets
22 and their associated contra accounts in accordance with OAR 860-038-0200(9)(a)(A)
23 through (F). These assets clearly relate to specific functional areas (e.g., thermal and hydro

1 generating plants, transmission towers and conductors, distribution poles, conductors,
2 substations, transformers, and service drops). Some general and intangible plant was
3 directly assigned, but the majority of these categories consist of many smaller assets without
4 a clear functional attribute so we allocated them based on labor.

5 **Q. How did you unbundle other rate base?**

6 A. We assigned or allocated other rate base using the criteria established in OAR
7 860-038-0200(9)(a)(G). Specifically, we evaluated other rate base on a ledger-by-ledger
8 basis and directly assigned where applicable (e.g., fuel inventories were assigned to
9 Production). For other categories, we allocated costs on an appropriate basis (e.g., deferred
10 credits related to post-retirement medical and life insurance are allocated based on labor).

11 **Q. Did you assign franchise fees to the Distribution function?**

12 A. Yes. Pursuant to OAR 860-038-0200(9)(c)(B)(i)(IV), PGE assigned franchise fees directly
13 to the Distribution function. We also assigned OPUC fees and writeoffs for uncollectibles
14 directly to the distribution function.

XII. Qualifications

1 **Q. Mr. Tooman, please state your educational background and experience.**

2 A. I received a Bachelor of Science degree in Accounting and Finance from the Ohio State
3 University in 1976. I received a Master of Arts degree in Economics from the University of
4 Tennessee in 1993 and a Ph.D. in Economics from the University of Tennessee in 1995. I
5 have held managerial accounting positions in a variety of industries and have taught
6 economics at the undergraduate level for the University of Tennessee, Tennessee Wesleyan
7 College, Western Oregon University, and Linfield College. Finally, I have worked for PGE
8 in the Rates and Regulatory Affairs department since 1996.

9 **Q. Mr. Tinker, please state your educational background and experience.**

10 A. I received a Bachelor of Science degree in Finance and Economics from Portland State
11 University in 1993 and a Master of Science degree in Economics from Portland State
12 University in 1995. In 1999, I obtained the Chartered Financial Analyst (CFA) designation.
13 I have worked in the Rates and Regulatory Affairs department since 1996.

14 **Q. Does this complete your testimony?**

15 A. Yes.

List of Exhibits

<u>PGE Exhibit</u>	<u>Description</u>
301	2011 Results of Operations Summary
302	Summary of Other Revenue Sources
303	Summary of Depreciation Expense by Plant Type
304	Impact of Depreciation Study by Plant Type
305	Summary of Amortization Expense
306	Summary of Income Taxes
307	Summary of Taxes Other Than Income
308	Summary of Capital Expenditures
309	Summary of Rate Base
310	Reasons for Changes in Rate Base since UE 197 et. al.
311	Lead Lag Summary Results
312	Biglow 3 2011 Net Revenue Requirement
313	Unbundled Results of Operations Summary