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September 15, 2008

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
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RE: **Docket No. UE197 – In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a general rate revision.**

Enclosed for electronic filing in the above-captioned docket is the Public Utility Commission Staff Surrebuttal Testimony.

/s/ Kay Barnes
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c: UE 197 Service List (parties)

PUBLIC UTILITY COMMISSION
OF OREGON

UE 197

STAFF SURREBUTTAL TESTIMONY OF

Carla Owings
Dustin Ball
Ed Durrenberger
Lisa Gorsuch
George R. Compton
Steve Storm
Paul Rossow

In the Matter of
PORTLAND GENERAL ELECTRIC COMPANY
Request for a General Rate Revision.

REDACTED

September 15, 2008

CASE: UE 197
WITNESS: Owings

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 800

Surrebuttal Testimony

September 15, 2008

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Carla Owings. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. ARE YOU THE SAME WITNESS THAT TESTIFIED EARLIER IN THIS PROCEEDING AS STAFF/100, OWINGS/1-29?

A. Yes. My Witness Qualification Statement is found in Staff/101,Owings/1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe the Staff position in response to PGE's rebuttal testimony regarding the following issues:

a. S-2 Research & Development
b. S-3 Workforce Issue
c. S-4 Corporate Incentives
d. S-5 Capital Expenditures
e. S-16 Revenue Sensitive Costs
f. S-19 Energy Audits
g. Case Summary

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared exhibits Staff/801-817, consisting of 49 pages.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

S-2 RESEARCH AND DEVELOPMENT (R&D)

Q. PLEASE EXPLAIN STAFF'S BASIS FOR ITS ORIGINAL ADJUSTMENT TO R&D.

A. As discussed at PGE/1900, Piro-Tooman/10, Staff relied upon PGE's response to Staff's Data Request No. 260-B-2 for its adjustment (*See* Staff/801, Owings/1-12) (*also See* PGE/1901, Piro-Tooman/5-6). In its response, PGE provides a "budget" of $1,995,000.

Q. IF PGE STATES THAT IT IS ONLY REQUESTING $1 MILLION IN THE TEST PERIOD FOR CORPORATE R&D (*SEE* PGE/500, PIRO-TOOMAN/8), WHY IS STAFF'S PROPOSED ADJUSTMENT $1.683 MILLION?

A. Staff believes that its adjustment to R&D should reflect a reduction to the test period that would bring PGE back down to R&D spending at historic levels, or approximately $350,000 for the test period. Staff believes its adjustment is appropriate for three reasons:

1. PGE provided a budget in its data response that demonstrates spending $1.995 million for R&D projects in 2009.

2. PGE states at PGE/500, Piro-Tooman/9, line 15, "PGE can use R&D funds <u>to improve the operation and maintenance of its generation and distribution system</u> and participate in opportunities to review and apply proposed improvements to its system through demonstration projects."

3. PGE does not provide ledger numbers in the 2009 budget that indicate where it intends to book its R&D costs[1], yet it demonstrates this for all other years (including 2008) in its

[1] Staff's inference here is that PGE *may* plan to book some of the projects indicated in the 2009 budget into O&M or other distribution accounts.

> response to Staff's data request. Nor does the Company isolate any project costs or give any indication which project costs it intends to pursue for the 2009 test period that add up to only $1 million.

Q. OF THE $1.995 MILLION OF PROJECTS PGE IDENTIFIES AT STAFF/801, OWINGS/12) (ALSO *SEE* PGE/1901, PIRO-TOOMAN/5-6), DOES STAFF BELIEVE THESE ARE WORTHY PROJECTS FOR PGE TO PURSUE?

A. Staff believes that many of the projects PGE identifies for the 2009 test period are projects that may be considered redundant to research being done by other entities, such as the Energy Trust of Oregon, or perhaps even the Oregon Department of Energy. In addition, since this type of research is mostly discretionary, Staff believes that this is an area that PGE could choose to reduce its costs to benefit ratepayers.

Q. DOES PGE PROVIDE EVIDENCE IN ITS REBUTTAL TESTIMONY TO SUPPORT ITS CLAIM THAT IT INTENDS TO SPEND ONLY $1 MILLION ON R&D?

A. No, it does not. PGE only states at PGE/1900, Piro-Tooman/10, that Staff has relied upon an erroneous amount and that Staff has "ignored" PGE's explanations. Although the Company states in a narrative that its intention is to spend $1 million on R&D (Id.), its response to Data Request 269-B indicating $1.995 million in 2009 R&D clearly conflicts with the narrative in PGE's testimony.

Q. PLEASE ADDRESS THE STATEMENT MADE BY PGE THAT STAFF "IGNORED PGE'S EXPLANATIONS" (*Id)* AND THAT STAFF WAS USING AN ERRONEOUS NUMBER.

A. In response to Staff's Data Request No. 447-b and c (*See* Staff/802, Owings/1-2), PGE states that it informed the Parties that both Staff and CUB were relying upon an erroneous amount for the test period by addressing the topic at the June 12th and 13th settlement discussions with Staff and Intervenors. As evidence of its efforts, PGE submitted a copy of a work paper it says it submitted as work sheet for settlement discussions that contains the following statement: "Staff's adjustment is based on a comparison to possible spending (as listed in Staff/801, Owings 11-12) rather than the forecast from our revenue requirement."

Q. WAS THE DOCUMENT PGE SUBMITS AS EVIDENCE THAT IT ATTEMPTED TO NOTIFY STAFF AND OTHER PARTIES THAT THEY WERE RELYING UPON ERRONEOUS INFORMATION SUBMITTED OR DISCUSSED IN THE JUNE 12TH OR 13TH SETTLEMENT DISCUSSIONS?

A. No, it was not. The document PGE submits in DR 447-A was never discussed at settlement because it was only *temporarily* submitted as a work sheet[2] and was **withdrawn** by PGE prior to settlement discussions and therefore, Staff did not review the work paper. At that point, PGE replaced the work sheet with an entirely different work sheet that did not contain the language PGE submits as evidence that it attempted to notify parties.

[2] Staff does not submit this document as an exhibit here because said document has information related to settlement discussions and is not appropriate to submit as an exhibit.

Q. DID PGE DISCUSS THE ERRONEOUS AMOUNT AS A TOPIC AT SETTLEMENT?

A. No it did not. PGE stated only that the amount for the test period should be $1 million not $1.995 million but gave no explanation as to why its data response would demonstrate $1.995 million if they only intended to spend $1.0 million.

Q. DID PGE MAKE ANY OTHER EFFORTS TO NOTIFY STAFF THAT IT WAS RELYING UPON ERRONEOUS INFORMATION?

A. No, it did not. In fact, PGE had many junctures at which it could have demonstrated to Staff that $2.0 ($1.995 rounded) million was **not** the amount it was requesting for the test period.

Q. DID PGE EVER INDICATE TO STAFF THAT ITS RESPONSE IN DR 269-B (STAFF/801, OWINGS/11-12) WAS ONLY A DEMONSTRATION OF HOW MUCH PGE *COULD* SPEND ON R&D?

A. No. Staff first saw this statement at PGE/1900/Piro-Tooman/10, line 14. On September 8, 2008, in response to Staff's Data Request No. 447-b (*See* Staff/802, Owings/1) PGE states that the $1.995 million is a "summation of specific topical research areas" for 2009 and was not a "specific budget calculation".

Q. DOES STAFF AGREE THAT THE $1.995 MILLION PGE SUBMITTED FOR THE 2009 TEST PERIOD WAS NOT A SPECIFIC BUDGET CALCULATION?

A. No. Staff notes PGE's original narrative response on the first page of 269-B (Staff/801, Owings/1) dated April 21, 2008. The last sentence states:"See

Attachment 269-B which provides **2008 and 2009 budgets** for R&D projects" (emphasis added). PGE makes no distinction in its response to these two budgets. Further, PGE does not distinguish which projects it intends to pursue that meet a budget of $1 million.

Q. IN ITS RESPONSE TO STAFF'S DATA REQUEST NO. 269, DOES PGE PROVIDE A BREAKOUT SHOWING WHERE COSTS WILL BE BOOKED IN REFERENCE TO ITS 2009 BUDGET?

A. No. Since there is no tie in this document to actual ledgers[3] or to ledgers that are listed in Exhibit PGE 501/Piro-Tooman/1, Staff has no reason to believe that the budget is exclusive to the ledgers in Exhibit 501/Piro-Tooman/1. PGE's method of accounting for its research and development projects may very well be tied to O&M or other accounts.

Q. WHY DOES STAFF BELIEVE THAT PGE COULD ACCOUNT FOR SOME OF ITS RESEARCH AND DEVELOPMENT PROJECTS AS O&M OR DISTRIBUTION COSTS?

A. At PGE/500/Piro-Tooman/9, line 15, the Company states "PGE can use R&D funds **to improve the operation and maintenance of its generation and distribution system** and participate in opportunities to review and apply proposed improvements to its system through demonstration projects."

Q. DOES STAFF PROPOSE AN ADJUSTMENT TO ITS ORIGINAL POSITION?

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[3] Note that in the 2008 budget PGE indicates the ledger number it intends to book costs to, but does not provide this information for 2009. Staff's original question on the data request is the same question for 2008 as it is for 2009, but PGE responded using two separate methods; an *actual* budget for 2008 and a *demonstration* of a budget for 2009.

A. No. Staff recommends that the Commission take official notice of PGE's response to Staff's data request no. 269-B (*See* Staff/ 801,Owings/1-12) (also *See* PGE 1901,Piro-Tooman/5 & 6; PGE/1901,Piro-Tooman/4). Staff refers specifically to the heading at the top of the document in Staff/ 801,Owings/10. PGE states that the "budget" is specific in its time period, for all research projects funded in 2008-to date (April/2008). Also note that each category begins with a bolded heading (I.e., "N44706 Corporate R&D, Supply Energy"). Please note that the N44706 is a reference to a specific PGE ledger number and is identified (as requested in the data request) for each of the four categories PGE is forecasting for the 2008 budget. Referring now to Staff/801,Owings/11; the heading states that this budget is for 2009. It does not indicate that it is 2009/2010, or any other time period for that matter. PGE states in its rebuttal testimony that its budget is $1 million rather than $1,995,000, then PGE should be made to demonstrate which projects and what amounts on attachment 269-B *are* accurate and can be relied upon.

Further, Staff asks that the Commission observe the asterisk(*) on attachment 269-B, at the top of the document in the box that refers to R&D Research Areas. PGE states the asterisk denotes the fact that..."some *projects* will undoubtedly be funded on a multi-year basis (beginning 2009 and ending in 2010)." Some projects listed in this document do not have *any* estimate of cost. Staff believes the language referenced by the asterisk means that certain *projects* could very well be repeated, refunded or continued into future years...but that does not indicate that the *costs* budgeted for 2009 will decrease as a result of projects going forward. Additionally, there is no indication on this document that PGE has any intention of spending anything less than a dollar amount of $1,995,000 on research and development.

Q. WHAT IS STAFF'S RECOMMENDATION FOR THE R&D ISSUE?

A. Staff recommends that the Commission accept Staff's original adjustment. Staff believes that its adjustment is appropriate given the fact that PGE may very well spend these amounts for R&D and book the dollars to accounts other than those labeled as R&D as stated in its testimony. Additionally, Staff relies heavily upon PGE to respond accurately to its questions during discovery and believes that the Commission should be able to rely on the amount of $1,995,000 as the amount that PGE is requesting in the test period for R&D. Staff believes that PGE's responses to data requests should be more transparent and that the Commission should advise PGE that it needs to make a good-faith effort to be more forthcoming in its responses to Staff and other Parties during the discovery phase of a proceeding.

S-3 WORKFORCE ISSUE

Q. WHAT DOES PGE PROPOSE IN ITS REBUTTAL TESTIMONY REGARDING ITS REQUEST FOR 130 INCREMENTAL FULL-TIME EQUIVALENTS (FTE)?

A. PGE's has structured its testimony regarding this issue in an extremely convoluted manner. The summary of PGE's testimony is (1) the Company is willing to remove the 7.5 FTE associated with the FERC 890-A requirements and (2) the Commission should not accept Staff's recommendation because PGE is not *really* asking for 130 incremental FTE, it is requesting 87 incremental FTE. PGE states that it disagrees with Staff's adjustment because it removes *more* FTE than PGE is even proposing to add (Staff's original adjustment removed 121 FTE and PGE's "revised" FTE count is 87 FTE (*See* PGE/1400, Tooman-Tinker/7, lines 6 and line 10). And (3) the Company claims to be requesting only 87 FTE rather than 130.

Q. CAN STAFF PROVIDE ANY CLARITY OR INSIGHT AS TO WHAT IT BELIEVES PGE IS REQUESTING?

A. Staff can only conclude that, just as was demonstrated in its request for an increase in R&D, there is a discrepancy between what PGE has requested and what it has demonstrated in its work papers and responses to data requests.

Q. WAS PGE'S ORIGINAL REQUEST AN INCREASE FROM 2007 BASE YEAR TO THE 2009 TEST PERIOD OF 130 FTE?

A. Yes. At PGE/1400, Tooman-Tinker/13, line 18, PGE states "PGE, in contrast, correctly calculated the increase...(move to PGE/1400, Tooman-Tinker/14, line 1) as **130** in its original filing..."

Following is a demonstration from PGE's exhibit 1405: at PGE/1405, Tooman-Tinker/4, under the heading of "Actuals" for 2007, PGE has the number 2,597[4]. Further down the page, under the heading Budget/Forecast, Budgeted Straight-Time, for 2009, PGE has the number 2,733. This number, 2,733 subtracted from 2,597 equals **136**[5] and represent the level of 2007 FTE to the level of 2009 FTE requested by PGE.

And finally, in a workshop held May 8, 2008, PGE provided parties with a worksheet reconciling the number of FTE it was requesting in this case. Staff has provided a copy of that worksheet as Staff/803, Owings/1. The top of this worksheet demonstrates that PGE is requesting **130** FTE.

Q. PGE/1400, TOOMAN-TINKER/7, LINE 10, STATES THAT PGE IS REQUESTING 87 FTE. CAN YOU EXPLAIN?

A. Yes. PGE claims that it requested an increase of 130 FTE, but actually, PGE's revenue requirement reflects an increase of 87 FTE, not 130. PGE claims that this occurs because "we made several adjustments to the filing that reduced the increase by 27 FTE (*See* PGE/1400, Tooman-Tinker/7, line 11)". Further, the Company states, that 16 FTE are related to Biglow Canyon Wind Project

4 This number has been adjusted to remove 32 FTE associated with Trojan lay-offs and does not represent the number provided to Staff in Data Response 203B.

5 This number changes from 130 because PGE has adjusted the FTE level to account for Trojan layoff in this exhibit.

and Port Westward and are already approved in rates through UE 180 and UE 184 (Id, at lines 12-13).

Q. DOES STAFF AGREE THAT PGE HAS MADE ADJUSTMENTS TO ITS ORIGINAL FILING THAT REDUCE ITS REVENUE REQUIREMENT TO REMOVE FTE?

A. Yes. PGE has adjusted its revenue requirement to remove 4 FTE related to the heat pump program as well as to add 7 FTE related to FERC/NERC requirements. These adjustments were performed in PGE's April 4, 2008 errata filing and net to an increase in PGE's FTE request of 3. However, in that same errata filing, it actually adds the 7.5 FTE related to the FERC 890-A regulations. So, at the end of the errata filing, PGE's request for FTE stands at 140.5, or a net addition of 10.5 FTE.

Q. DOES STAFF AGREE THAT 16 FTE RELATE TO THE PORT WESTWARD AND BIGLOW CANYON PROJECTS?

A. Yes. Staff agrees that 16 FTE are attributable to reconciling the count of 130 FTE. However, PGE has not removed these 16 FTE from its revenue requirement request and therefore should be counted in the total overall request. However, to reconcile the number of FTE PGE is requesting in order to isolate the differences between Staff's proposal and PGE's request, we remove 16 FTE from the 140.5 FTE. This brings us to a request of 124.5 FTE. And finally, Staff agrees that PGE has also performed an adjustment to its revenue requirement to remove 7.5 FTE related to FERC 890-A (the same 7.5

FTE it added in its April 4, 2008 errata filing) in its rebuttal as indicated at PGE/1400, Tooman-Tinker/5. That makes the FTE count 117, not 87 FTE.

Q. AT PGE/1400, TOOMAN-TINKER/10, TABLE 4, PGE CLAIMS THAT IT HAS REDUCED ITS REVENUE REQUIREMENT BY APPROXIMATELY $2.0 MILLION AS AN OFFSETTING CREDIT THROUGH "UNFILLED POSITIONS". WHY DOES STAFF DISPUTE THIS ISSUE?

A. Staff disputes that this adjustment lowers PGE's FTE level for 2009 from the 2,733 FTE PGE reported for two reasons. First, the Company represented its 2009 test period with a specific wage level and a matching FTE count of 2,733. If PGE adjusted its 2009 test period to "remove" 30 positions, then the FTE count is 30 fewer than the 2,733 PGE provided Staff and the Parties in its original filing. By PGE's testimony the FTE count should be 2,703. This demonstrates yet another disparity between PGE's testimony, work papers and its data responses. Secondly, Staff disputes this because this adjustment took place in PGE's original filing. PGE made this adjustment and *then* stated its FTE count. PGE has had ample opportunity to notify Parties if it misstated its FTE count. PGE has made no such statements. Further, Staff typically relies on PGE's FTE count and its matching wage and salary amounts to perform a three-year Wage & Salary study. This study, applied to each class of employee (I.e., Officer, Hourly, Exempt & Union), compares total test period wages and salaries with the average level three years prior adjusted for inflation. If PGE were to provide an estimate of wages and salaries as though there were 2,733 FTE rather than 2,703 FTE it now says it has included in its case, then the analysis of the three-year wage and salary study is flawed due to mis-matched information. This mis-match would spread the total amount of wages and salaries among a larger pool of workers giving a false indication of lower wages per employee. This would misrepresent the amount PGE could potentially be paying each employee.

Q. PLEASE EXPLAIN STAFF'S PROPOSAL.

A. In aid of that explanation, we must begin with the original Staff proposal. Staff's original proposal removed 121 FTE. Staff relied upon PGE's response to Data Request No. 203-B and 319-A where it reported 2,560 Actual FTE for 2007 (*See* Staff/804, Owings/1-2).

Q. DID PGE AMEND ITS ACTUAL FTE COUNT FOR 2007 OR 2009 PER ITS RESPONSE TO 203-B AND 319-A (*SEE* STAFF/804, OWINGS/1-2)?

A. No. However, in a May 9, 2008 workshop PGE pointed out that the 2007 "actual" number of 2,560 FTE is not compatible with its 2009 "forecast" of 2,733 FTE because the 2,733 FTE forecast includes a budget of 52 FTE for overtime even though those employees are exempt from overtime.

Q. WHAT IS PGE REFERRING TO WHEN IT STATES THAT IT HAS "BUDGETED" FOR EXEMPT OVERTIME FTE'S?

A. PGE would ask the Commission to consider that PGE has budgeted additional FTE in its "straight-time" "ACTUAL" FTE's even though the physical employee count is significantly lower. The Commission can relate to this concept in the sense that the Commission's Staff of analysts are exempt from overtime. However, Staff members often are traveling over weekends and working in off-hours and even on holidays to meet statutory and administrative deadlines. Let's say the Commission employs approximately 30 staff analysts. Although the Commission may not have plans to specifically request more FTE, in order to prepare its budget, and consistent with the method proposed by PGE, the Commission would submit a budget representing 35 staff analysts (FTE) even though it only employs 30 people performing the required tasks. Since the Commission pays its analysts only straight-time pay or salary, the remaining 5 positions (FTE) funded by the legislature would simply be discretionary dollars.

Q. DOES PGE SEPARATELY ACCOUNT FOR OVERTIME WHEN IT BUDGETS THE NUMBER OF FTE?

A. Yes. PGE separately accounts for 116 FTE as overtime FTE for 2007 and 93.5 FTE for 2009 (*See* Staff/805, Owings/1: "PGE 800 workpapers PGE Utility Full-Time Equivalents (FTE) by Year, by Division": *See* "**Total Utility Over Time" last column, headed 2009 test year)**. For 2009, PGE budgets an additional $14.7 million for overtime (*See* Staff/806, Owings/1). Staff makes no adjustments to these amounts per PGE's original request.

Q. IF THE COMMISSION WERE TO EXCLUDE THE ADDITIONAL 52 FTE'S THAT PGE BUDGETED INTO ITS STRAIGHT-TIME CALCULATION OF FTE'S, WHAT IS THE BASE LEVEL OF FTE FOR 2007?

A. The base level for 2007 should be the 2,560 *actual* FTE employed by PGE in 2007. This is the level that Staff bases its analysis on and this is the level provided by PGE in response to Data Request Nos. 203-B and 319-A (Staff/804, Owings/1-2).

Q. DOES STAFF PROPOSE ANY CHANGES TO ITS ORIGINAL WORKFORCE ADJUSTMENT?

A. Yes. However, the revisions Staff proposes still assume the same base level of actual employees for 2007 of 2,560 (*See* Staff/807, Owings/2). To that amount Staff originally applied a growth rate of 0.50 percent and in addition, provided an estimate of an additional 26 positions in deference to Biglow Canyon's and Port Westward's full-year status.

Staff is willing to revise its growth rate to a 1.45 percent growth rate, rather than the .50 percent growth rate used originally. Staff makes this recommendation in acknowledgment of the Trojan lay offs and the growth rate proposed by PGE. In doing so, Staff removes the adjustment to add 26 FTE due to the fact that revising the growth rate **allows PGE a growth of 75 *actual* employees between 2007 and 2009.** This revision reflects a disallowance of 98 FTE rather than 121 FTE in Staff's original proposal.

In addition, Staff is revising its loading percentage from 52.18 percent to the 48.5 percent requested by PGE at PGE/1400, Tooman-Tinker/10, line 11. And finally, Staff is willing to revise its split for the allocation of capital costs to expense from 73 percent O&M and 27 percent capital to 71.75 percent O&M and 28.25 percent capital.

The result of these revisions to Staff's adjustment changes revenue requirement by approximately $3.0 million. Staff's original adjustment was a reduction to revenue requirement by approximately $14.2 million. The revisions reduce revenue requirement by approximately $11.2 million (*See* Staff/807, Owings/1-2).

Q. ONCE STAFF MAKES THESE REVISIONS, DOES ITS ESTIMATE OF DOLLAR PER FTE CLOSELY MATCH PGE'S ESTIMATE?

A. Yes. It very closely matches PGE's estimate. Using Staff's revised amounts, Staff's dollar per FTE is approximately $77,000 (*See* Staff/807, Owings/2) compared to $75,764 used by PGE at PGE/1400, Tooman-Tinker/10/line 7. However, if indeed the Company has actually mis-stated its 2009 FTE level by representing a level of 2,733 FTE but by making an adjustment to remove 30 FTE, then Staff's estimate of cost per employee is incorrect because that estimate is based on the 2,733 FTE that are presented in PGE's case. As discussed above, removing 30 FTE without changing the level in the case skews the relationship between the number of FTE represented for the amount of wages and salaries the Company has presented. In other words, rather than the dollar per FTE being $77,000, adjusted for the proper level of FTE the amount would be $77,870 per FTE. This would have an overall effect of increasing Staff's adjustment by $125,000. In addition, Staff may want to consider another look at whether PGE's 3-year wage & salary adjustment is performed considering the proper number of FTE.

Q. CAN YOU PLEASE ADDRESS THE ISSUE RAISED BY PGE AT PGE/1400, TOOMAN-TINKER/6: "STAFF'S ADJUSTMENT MAKES NO EFFORT TO EVALUATE THE BASIS FOR THE INDIVIDUAL POSITIONS

BEING PROPOSED OR THE VALIDITY OF THE SERVICES OR REQUIREMENTS PGE IS TRYING TO ACCOMPLISH WITH THEM?"

A. Yes. Staff has based its recommendation of the appropriate number of FTE primarily on historic growth. Staff's proposed adjustment provides for an increase of 75 FTE between 2007 and 2009, or approximately 3 percent increase. Staff believes that historical growth provides a strong indication of the employee levels PGE has needed from year to year. The company can always point to "new" programs or new responsibilities in any given year; for this reason, 2008 and 2009 are hardly unique in that respect. The Commission's role should not be to micromanage the company's operations by determining the need for each and every position within the company -- that would require a full audit of not only the 130 PGE proposed positions, but all 2,597 existing positions, as well. Instead, the Commission should set revenues to allow recovery for a reasonable level of employees and leave it to the company to establish priorities.

Q. CAN YOU PLEASE SUMMARIZE STAFF'S PROPOSAL?

A. Yes. Staff proposes that the Commission disregard PGE's estimate of straight-time FTE that includes a budgeted amount of overtime for exempt employees separate from an additional 93.5 overtime employees PGE requests in its filing. Staff recommends that the Commission rely upon a base of 2,560 as established by PGE in its responses to Staff's data requests. Staff also recommends the Commission allow for a 1.45 percent growth for 2008 and 2009, for a total of 75 incremental employees above the 2007 (UE 180) actual

FTE count. This amount represents a total of 2,635 straight-time FTE for 2009 test period. The proper adjustment to reflect Staff's proposal would be a reduction to PGE's original request of approximately $11.2 million; approximately $8.0 million to O&M and $3.2 million to capital costs.

S-4 CORPORATE INCENTIVES

Q. WHAT DOES PGE PROPOSE IN ITS REBUTTAL TESTIMONY REGARDING CORPORATE INCENTIVES?

A. The Company proposes to remove incentives for officers and directors in this proceeding (See PGE/1500, Barnett-Bell/3). As a result the Company proposes to remove Officer ACI in the amount of $1.7 million and the Officer's Stock Incentive Program in the amount of $1.7 million.

Q. DOES THIS ADJUSTMENT REFLECT THE ENTIRE AMOUNT OF OFFICER ACI AND THE OFFICER'S STOCK INCENTIVE PROGRAM FOR THE 2009 TEST PERIOD?

A. For the Officer's ACI, it does. However, for the Officer's stock incentive program, it does not. Staff submits Staff/808, Owings/1, which demonstrates that the amount included in the 2009 test period for Officer's stock incentive program is $2.8 million rather than the $1.7 million for which PGE proposes in rebuttal to not pursue recovery. Staff's original adjustment already includes the removal for the entire amount of Officer ACI and Officer's stock incentive. In addition, Staff's adjustment also removes 50% of CIP and teamworks bonuses. So, this proposal by PGE to remove all of the Officer ACI and a portion of the Officer's stock incentive does not change Staff's original proposed adjustment (*See* Staff/809, Owings/1-2).

S-5 CAP EX

Q. IN YOUR ORIGINAL TESTIMONY YOU DISCUSSED HOW PGE COULD NOT ACCURATELY PREDICT WHEN LARGE CAPITAL EXPENDITURES SUCH AS THE SELECTIVE WATER WITHDRAWAL (SWW) FACILITY WOULD BE PUT INTO SERVICE. HAS PGE ADEQUATELY RESPONDED TO THESE CONCERNS IN ITS REBUTTAL TESTIMONY?

A. No, quite the opposite. In its rebuttal testimony PGE has only further confirmed Staff's concerns of the company's inability to accurately predict when these large capital items, such as the SWW, will go into service. At PGE/1300, Piro/28, the Company adjusts its revenue requirement in this case to move the SWW by one month later in the test period. PGE now believes based on updated information that the SWW will not go into service until April 2009, one month after its original in-service date. In addition, PGE states that it has "removed the hydro relicensing costs from the rate request given that it appears this project may not receive the FERC license during the test year and, hence, be completed" (*See* PGE/1300, Piro/28, lines 8-10). These costs are related to the Clackamas relicensing costs that Staff discusses at Staff/100/Owings/21. Staff asserts in its direct testimony that there is a good chance these costs will not close-to-books prior to the end of the test period. PGE has confirmed that this is, in fact, the case. Staff believes that the necessary adjustments PGE has made due to changing forecasts demonstrates why Staff recommends the Commission use caution when considering allowing large capital additions into ratebase when those additions are not projected to be placed into service until after rates have gone into effect.

Q. ONCE RATES GO INTO EFFECT ON JANUARY 1, 2009, WILL PGE ADJUST RATES FOR PLANT THAT DOES NOT CLOSE TO BOOKS AT THE TIME PGE ESTIMATES?

A. No.

Q. OVER TIME HAVE THERE BEEN SIGNIFICANT CHANGES TO THE DESIGN AND CONSTRUCTION OF THE SWW FACILITY AS WELL AS OTHER HYDRO PROJECTS STAFF IS REVIEWING?

A. Yes. PGE has changed its design structure significantly from the original proposed model for the SWW, which has caused costs to increase from an original estimate of $65 Million to expectations of $81 Million as of 2009. This is an increase of approximately 25% over original estimates (*See* Staff/810, Owings/1-5).

Q. HAS PGE PROVIDED DETAIL FOR THE SIGNIFICANT COST LEVEL INCREASES THAT THE COMPANY HAS EXPERIENCED WITH RESPECT TO THE SWW FACILITY?

A. No, not to date. Although, Staff has requested additional detail for the increase in costs of the SWW facility, PGE has provided only high-level answers that discuss the evolution of the design of the SWW facility and bulleted items for topics such as project delay, increases in contract scope, and contract additions. PGE does not have the detail organized in a manner that is easily auditable nor is it compiled in a manner that answers the questions Staff has raised. It will take Staff and the Company many hours to complete an audit of these costs.

Q. HAS PGE SHOWN AN INCREASE IN THE PELTON ROUND BUTTE MITIGATION COSTS AS WELL AS THE SWW FACILITY?

A. Yes. Staff asked PGE to provide comparisons of original estimates of costs contained within the Final Environmental Impact Statement (FEIS) in Data Request No. 369 attachment B (See –Staff/811, Owings/1-2), and PGE's reasoning behind any significant changes from these original estimates. PGE provided a comparison that showed that costs have increased overall since the FEIS by 318 percent. PGE's explanation in response to Staff's Data Requests was that costs were unknown at time of FEIS.

Q. HAS PGE PROVIDED ANY COST BENEFIT ANALYSIS THAT JUSTIFIES THE LARGE INCREASES OF COSTS THAT STAFF HAS OBSERVED FROM THE BEGINNING OF A HYDRO PROJECT TO THE CLOSING OF THE PROJECT?

A. No. In PGE rebuttal testimony, PGE/1300, Pirol/21, Lines 1-6, Mr. Piro states that projects that are "necessary by regulatory or service requirements" do not undergo cost-benefit analysis because "doing nothing is not an option." In addition, given that the marginal costs of hydro resources is significantly below that of the next available marginal resource, the incentives for PGE to exercise cost containment controls is low.

Q. PGE PROPOSES, AS AN ALTERNATIVE TO INCLUDING SWW IN RATES FOR JANUARY 1, 2009, THAT THE COMMISSION ALLOW PGE

TO TRACK IN THE LARGER CAPITAL PROJECTS SUBJECT TO CERTAIN CONDITIONS. DOES STAFF AGREE TO PGE'S PROPOSAL TO TRACK THESE LARGER CAPITAL PROJECTS?

A. At PGE/1300, Piro/28, the Company proposes that the Commission to allow it to track the costs subject to:

- The prudence of the project is already determined in the preceding general case.
- The price change will be based on the annualized revenue requirement impact of the project with all associated costs and benefits.
- No further updates will be performed until the next general rate case.

Staff recommends that the Commission *does not* accept PGE's proposal under these terms. Staff raises the issues above to demonstrate the complexity in which these large capital projects come into service often years after the inception of the project. For PGE to propose that the prudence of the project is already determined in the preceding general case is an unreasonable assumption. In the case of the hydro projects, there is some leeway to assume some prudence in that the Company first decision is to choose between relicensing compliance and abandoning the resource. However, Staff cannot assume that relicensing should come at any cost nor that all costs toward certain hydro relicensing are directly tied to license compliance. Staff believes that there is potential that PGE isn't exercising adequate cost control due to the fact that there is a high threshold between the current cost on the books for the resource and the level at which the investment becomes uneconomic.

Staff is unclear precisely what PGE proposes in its other two conditions, and is therefore unwilling to commit to the Company's proposal. However, in its rebuttal testimony[6] PGE only adjusts out the hydro relicensing that is related to the Clackamas project due to close to books in December of 2009. If it is genuinely proposing a tracking mechanism, Staff believes it should also have made adjustments to remove the projects PGE proposes to separately track.

Q. DOES STAFF PROPOSE AN ALTERNATIVE TO ADDRESS THE ISSUE OF LARGE CAPITAL COSTS BEING INCLUDED IN RATES YET NOT USED AND USEFUL THE FIRST DAY RATES ARE IN EFFECT?

A. Yes. Staff believes that they should be handled similar to the method Staff and other parties handled UE 189, Automated Meter Reading. In that case, PGE requested it be included in the UE 180 general proceeding; however, due to the complex nature of the review, PGE removed it from the general rate proceeding and it was handled as a single-issue rate case. While Staff is not in favor of all large capital projects being included in this manner, Staff believes that this is an appropriate method to handle PGE's SWW projects. In a single-issue rate case, full regulatory review takes place as opposed to a "tracking" method that is subject to pre-agreed upon outcomes.

Q. WHAT DOES STAFF PROPOSE FOR THE OTHER LARGE CAPITAL COSTS PGE HAS INCLUDED IN ITS UE 197 RATE REQUEST?

[6] *See* PGE/1300, Piro/28.

A. The Clackamas relicensing issue is resolved as PGE has agreed to remove it from its rate request in rebuttal testimony[7]. Staff believes the SWW should also be removed (as per Staff's position in direct testimony) and filed separately as single-issue rate case. The remaining capital costs are as follows:

	Close to Plant	Date to close
Boardman Costs	$6,986,000	April 30, 2009
Boardman Costs	$17,202,000	July 31, 2009
Boardman Costs	$11,812,000	December 31, 2009

Q. HAS STAFF REMOVED THESE COSTS IN ITS ADJUSTMENT?

A. Staff has made an adjustment to represent the removal of these costs from PGE's requested revenue requirement (*See* Exhibit Staff/812, Owings/1). However, since Staff does not have enough information to determine exactly what the depreciation, AFDC and any other associated costs are for each project, Staff does not believe it has accurately represented the true adjustment, only a proxy for the actual amounts. The actual adjustment would be considerably larger than what Staff submitted in its original adjustment. A Data Request has been issued to acquire the proper information.

Q. PLEASE DISCUSS THE CAPITAL COSTS ASSOCIATED WITH THE BOARDMAN PLANT?

A. As can be seen from the table above, PGE is requesting Boardman costs that are also slated to close-to-books in December of 2009. Again, given the

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[7] *Id.*

potential that a project can go beyond its original projected completion date, PGE should recognize the importance of these costs not being included in rates that will go into effect an entire year before the completion of the project. The Boardman projects due to be completed in April and in July should be tracked separately to assure prudence in cost as well as whether the project itself is prudent. Staff recommends that the Commission order PGE to remove all associated costs related to these three projects. The Company has stated in other discussions that there are several drivers that may require the Company to return sooner than it would like to another general proceeding; the Company can then request these costs be included as they will likely be closed-to-books and in service.

Q. PLEASE SUMMARIZE STAFF'S PROPOSAL.

A. PGE's rebuttal testimony proposes to remove the capital costs associated with the Clackamas relicensing. The adjustment PGE submits is considerably different than the adjustment Staff proposed in its original testimony to remove the costs associated with Clackamas. Therefore, Staff reconciles its original adjustment attributable to removing costs associated with Clackamas. Staff has issued a data request in aide of discovering the proper amounts to adjust PGE's revenue requirement request to capture all costs associated with each large capital project that Staff has identified. In the meantime, Staff's remaining adjustments attributable to SWW and Boardman costs remain as described in Direct Testimony at Staff/108, Owings/1. The result of reconciling to PGE's Clackamas adjustment and Staff's original adjustments decrease PGE's original revenue requirement request by approximately $13.2 million.

S-16 REVENUE SENSITIVE COSTS

Q. WHAT DOES PGE PROPOSE IN ITS REBUTTAL TESTIMONY REGARDING THE ISSUES RELATED TO REVENUE SENSITIVE COSTS?

A. PGE/1400 concedes to the issue raised by Staff related to the State Tax rate adjustment and PGE reduces its revenue requirement request by approximately $.6 million (*See* Staff/814, Owings/4).

Q. DOES THIS ADDRESS ALL ISSUES ORIGINALLY RAISED BY STAFF RELATED TO THE REVENUE SENSITIVE COSTS?

A. No. It does not address the issue raised by Staff regarding PGE's uncollectible rate. Staff Witness Paul Rossow will address this issue at Staff/1400.

S-19 ENERGY AUDITS

Q. PGE STATES IN ITS REBUTTAL TESTIMONY THAT IT DOES NOT PERFORM ENERGY AUDITS AND THAT STAFF MADE AN ASSUMPTION BASED ON A TWO-MINUTE NEWS SEGMENT. CAN YOU PLEASE EXPLAIN?

A. Yes. At PGE/1700, Hawke/2 PGE states that KATU News "mislabeled PGE's customer service investigation of high bill inquires as 'energy audits'. *See Id.* at lines 6 – 7. Staff based its determination of PGE's activities on PGE's response to Staff's data requests found at Staff/112. Further, Staff submits as an exhibit Staff/813, Owings/1-3. This exhibit demonstrates that both in the Dex online phone book and in the 2007-2008 edition of the Yellow Book, p. 242, PGE lists separately a phone number for its "Energy Efficiency-Energy Experts". Since PGE refers to *itself* as "Energy Experts," Staff is not persuaded by PGE's testimony that KATU "mislabeled" its customer service investigations. Staff recommends the Commission accept Staff original adjustment to remove costs associated with these audits.

CASE SUMMARY

Q. PLEASE SUMMARIZE STAFF'S ADJUSTMENTS IN THIS CASE.

A. The table below lists Staff's recommended adjustments to PGE's proposed non-NVPC revenue requirement request in this proceeding.[8]

Issue	Description	Amount ($000)	Pertinent Exhibit
S-2	Research and Development	(1,752)	Staff/800, Owings/2
S-3	Workforce Adjustment	(8,891)	Staff/800, Owings/6
S-4	Corp Incentives	(6,963)	Staff/ 800, Owings/17
S-5	Cap Ex	(13,286)	Staff/ 800, Owings/18
S-9	A&G and O&M	(8,336)	Staff/ 300, Ball
S-10	WECC, RTP & flow mitigation	(156)	Staff/ 400, Durrenberger
S-11	Fixed Plant Costs	(6,348)	Staff/ 400, Durrenberger
S-13	NERC/WECC, RCM, Misc	(520)	Staff/ 400, Durrenberger
S-14	Property Tax Adjustment	(3,001)	Staff/ 300, Ball
S-16	Revenue Sensitive Costs	(1,805)	Staff /800, Owings/25 Staff/200, Rossow
S-19	Energy Audits	(287)	Staff/ 800, Owings/26
S*	Rounding	(121)	Staff/800, Owings
	Total Adjustment	**$(51,466)**	

Staff proposes total adjustments to PGE's revenue requirement request (net of NVPC) of $51.4 million. This amount compares to PGE/1400, Tooman-Tinker/5 proposed adjustments of approximately $16.2 million and is net of the stipulated adjustments filed on August 5, 2008. The stipulated adjustments are summarized as follows:

[8] See PGE/1300, Piro/10: "PGE case before rebuttal" ($49.0 for O&M/A&G plus $29.3 million for All Other equals $78.3 million). PGE's rebuttal case included reductions of $16.2 million to this amount.

Stipulated Issues		
Issue	Description	Amount
S-0	Rate of Return	(12,906)
S-1	Other Electric Revenues	471
S-6	Lease Adjustment	0
S-7	Fuel Adjustment	0
S-8	Membership Adjustment	0
S-12	Kelso Beaver Pipeline Transmission	(1,040)
S-17	Schedule 300	0
S-18	Port West/Biglow Canyon True-up	(113)
	Total Revenue Requirement Impact	**(13,588)**

Summing Staff's proposed adjustments to the stipulated issues listed above totals approximately $65 million in reductions to PGE's original revenue requirement request of $147.3 million. These amounts exclude the Company's requests for Net Variable Power Cost Updates and address only the revenue requirement request for issues raised in the general proceeding. The remaining revenue requirement request proposed by Staff is $77.1 million (*See* Staff/814, Owings/1-2) increase to PGE's current rates net of NVPC updates. This increase considers the increase in NVPC originally requested by PGE as well as the Stipulated agreement adjusting NVPC by approximately $5.0 million. However, this amount does not include any NVPC updates from the original filing[9]. Staff exhibit Staff/806, Owings/1-5 demonstrates the revenue requirement for Staff's proposal.

Q. HOW DOES STAFF'S CURRENT POSITION COMPARE WITH ITS POSITION IN DIRECT TESTIMONY?

A. At Staff/100, Owings/4, Staff was requesting a reduction to PGE's revenue requirement request of $59.1 million related to other costs in this case compared to the $51.4 million it proposes in this testimony. PGE's original revenue requirement request *for all other costs* was approximately $92.9 million. On August 5, 2008, Staff, PGE and all other parties Stipulated to combined adjustments totaling approximately $13.6 million leaving a requested increase of approximately $78.3 million. Staff's proposal would reduce that request for an increase in costs to approximately $26.9 million, or approximately 1.6 percent.

Q. WHY DOES STAFF BELIEVE THAT THIS IS A REASONABLE INCREASE?

A. Staff believes that $26.9 million for all other costs is a reasonable increase due to the fact that PGE still has many areas it can review for cost containments. Staff believes that inefficiencies that exist prior to a utility company filing its rates can be projected forward into the next rate case due to a historical view of the company's costs (*See* CUB/100, Jenks/6-7).

Q. DOES STAFF BELIEVE IT HAS IDENTIFIED ALL POSSIBLE EFFICIENCIES IN ITS PROPOSED ADJUSTMENTS?

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[9] July 11, 2008 NVPC of $103.0 million

A. No. In order to gain better efficiencies, Staff and Intervenors would be required to audit each cost category which is not feasible during a general proceeding. At CUB/100, Jenks/8, CUB states that "PGE rates are 26% higher than PacifiCorp's and 76% higher than Idaho Power's." In response, at PGE/1300, Piro/16, lines 12-14, PGE states that CUB's view is simplistic and in order to be performed correctly, it would require research to normalize all thee components that are not directly comparable. However, PGE fails to demonstrate otherwise even though it has performed benchmarking studies of its own. In response to Staff's Data Request No. 444-f, PGE provided benchmarking studies that Staff submits here as confidential exhibits Staff/815, Owings/1 and Staff/816, Owings/1-4. Staff submits these confidential graphs to demonstrate**CONFIDENTIAL** [redacted] **CONFIDENTIAL**. In addition, Staff has created confidential exhibit Staff/817, Owings/1-2 to demonstrate**CONFIDENTIAL** [redacted] **CONFIDENTIAL** Staff believes that this study demonstrates that PGE's current residential rates range from **CONFIDENTIAL** [redacted], respectively **CONFIDENTIAL** (*See* confidential exhibit Staff/817, Owings/1). With respect to the rates PGE is proposing its residential rates would range from **CONFIDENTIAL** [redacted] **CONFIDENTIAL** (*See* confidential exhibit Staff/817, Owings/2). The burden is on PGE to show the reasonableness of its proposed cost increases. Issue after issue Staff has highlighted PGE's lack of substance to demonstrate a need for the cost increases it has requested. PGE discusses weakness in an adjustment supported by Staff or other parties, but fails to demonstrate a clear need or justification for the cost it is requesting. At CUB/100, Jenks/50, CUB proposes a $17 million overall revenue requirement reduction for cost containment. Staff recommends the Commission adopt CUB's proposed adjustment, or alternatively, require PGE to demonstrate through rigorous benchmarking studies that its current operations have no optional cost containment options.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Exhibits in Support of Surrebuttal Testimony

September 15, 2008

May 8, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated April 21, 2008
Question No. 269

Request:

Please provide a summary for each year of the amount PGE has spent on Research and Development for the years 2002 through 2007.

a. Please provide a breakout for each year identifying the major projects PGE researched and the amount spent in that category for the time period between 2002 and 2007.

b. Please identify the amount budgeted for 2008 and 2009 for in each major category PGE identifies as projects for research and development.

Response:

See Attachment 269-A that provides annual R&D projects and amounts spent for the years 2002 through 2007.

PGE did not conduct R&D projects in 2003. Company-wide efforts at cost containment were the driving factor in this decision. In the period 1994 to present, this was the only time where R&D, as a corporate function, was not pursued.

See Attachment 269-B which provides 2008 and 2009 budgets for R&D projects.

UE 197
Attachment 269-A

Research and Development Projects

See Excel File
(Projects 2002 through 2007)

2002 EPRI and EPRI Related Internal Research & Development Projects - Yearly Budget

Activity Code	Title	Type	Ledger#	Spent
ADMIN	Management of R&D Files	Research	N44709	($73.85)
BIO03	Exploiting Farm-based Methane Digester Fuel	Research	N44706	$712.50
CSV23	Proton Exchange Membrane (PEM) Fuel Cell	Research	N44708	$47,378.18
DIST12	Capstone Users Group - EPRI TC	Membership	N44707	$0.00
ENV13	Ultra-Low Sulfur Diesel and catalytic Device Testing on PGE Trucks	Research	N44707	$88.09
EPRI1	EPRI Membership	Membership	N44705	$292,745.22
GEN01	Combustion Turbine and Combined Cycle Users Organization (CTC2)	Membership	N44711	$44,108.00
GEN02	Testing Dual Fuels for Dispatchable Standby Generator	Research	N44708	$45.00
GTE11	Edison Welding Institute (EWI) Research	Research	N44711	$0.00
METT1	EPRIWEB Conference Attendance	Conference	N44709	$0.00
			Totals	$385,003.14

2003 EPRI and EPRI Related Internal Research & Development Projects - Yearly Budget

Activity Code	Title	Type	Ledger#	Spent
			Totals	$0.00

PGE did not conduct R&D projects in 2003. Company-wide efforts at cost containment were the driving factor in this decision. In the period 1994 to present, this was the only time where R&D, as a corporate function, was not pursued.

2004 EPRI and EPRI Related Internal Research & Development Projects - Yearly Budget

Activity Code	Title	Type	Ledger#	Spent
CSV24	Customer Insights Primen Research Model	Membership	N44708	$12,500.00
CSV25	Market Driven Demand Response	Membership	N44705	$10,000.00
CSV26	Energy Use Load Profiles	Membership	N44705	$50,000.00
CSV27	Power Quality Knowledge-Based Services	Membership	N44705	$20,000.00
ENV13	Ultra-Low Sulfur Diesel and catalytic Device Testing on PGE Trucks	Research	N44707	$11,279.00
ENV14	Occupational Health and Safety: Ergonomics	Membership	N44708	$33,170.60
GEN01	Combustion Turbine and Combined Cycle Users Organization (CTC2)	Membership	N44711	$40,031.00
GEN03	Capacity, Performance, Emissions and Combustor Stability Enhancements	Research	N44706	$32,940.00
GEN04	Distributed Generation - Primen Research	Membership	N44706	$9,500.00
			Totals	$219,420.60

2005 EPRI and EPRI Related Internal Research & Development Projects - Yearly Budget

Activity Code	Title	Type	Ledger#	Spent
CSV28	Demand Response Technical Demonstrations	Membership	N44705	$30,000.00
CSV29	Power Quality Knowledge-Based Services (P97) (see CSV27)	Membership	N44705	$25,000.00
CSV30	Commercial Customer Load Control Technology Test Using DSG Communications Software	Research	N44705	$11,000.00
ENV13	Ultra-Low Sulfur Diesel and catalytic Device Testing on PGE Trucks	Research	N44707	$4,223.00
ENV15	Chemical Inventory Toxicity reduction, assessment and management Pilot	Research	N44708	$31,022.00
ENV16	Selective catalytic Reduction	Research	N44708	$99,200.00
GEN02	Testing Dual Fuels for Dispatchable Standby Generator	Research	N44708	$64,038.00
GEN04	Distributed Generation - Primen Research	Membership	N44706	$9,500.00
GEN05	Distributed Generation - Primen Research	Membership	N44706	$15,000.00
GEN06	Coal Fleet for Tomorrow: Accelerating the Deployment of Advanced Coal-Based Plants	Research	N44706	$50,000.00
			Totals	$338,983.00

2006 EPRI and EPRI Related Internal Research & Development Projects - Yearly Budget

Activity Code	Title	Type	Ledger#	Spent
ADMIN	Management of R&D Files	Research	N44709	$0.00
CSV31	Smart Chip Appliance Technology	Research	N44705	$12,250.00
CSV32	Power Quality Knowledge-Based Services	Membership	N44705	$25,000.00
DIST13	GridApp Utility Consotium Membership	Membership	N44707	$5,000.00
ENV15	Chemical Inventory Toxicity reduction, assessment and management Pilot	Research	N44708	$902.00
ENV16	Selective catalytic Reduction	Research	N44708	$10,000.00
GEN07	Maintenance, Engineering and Project Management at PGE.	Research	N44706	$7,471.00
GEN08	CEA Technologies Inc/Hydraulic Plant Life Interest Group	Membership	N44706	$7,000.00
GEN09	Gasification-Based Power Plant Development and Deployment	Membership	N44706	$66,500.00
GEN10	OSU Wave Energy Research	Research	N44706	$15,000.00
GEN11	Distributed Generation - Primen Research	Membership	N44706	$18,000.00
			Totals	$167,123.00

2007 EPRI and EPRI Related Internal Research & Development Projects - Yearly Budget

Activity Code	Title	Type	Ledger#	Spent
CSV33	Smart Chip Appliance Technology Trial	Research	N44705	$0.00
DIST14	GRIDAPP Utility Consortium Membership	Membership	N44707	$50,000.00
EDA01	EPRI Deposit Account from GEN17, Tailored Collaboration.			$16,872.00
ENV17	Atmospheric Sampling of Mercury	Research	N44706	$0.00
ENV18	EPRI's Program 75 - Integrated Environmental Controls	Membership	N44706	$70,000.00
ENV19	Big Sky Carbon Sequestration Partnership	Membership	N44706	$10,000.00
GEN12	Bio-fuel & Catalytic Exhaust Treatment Research	Research	N44706	$49,779.00
GEN13	CEA Technologies Inc/Hydraulic Plant Life Interest Group	Membership	N44706	$21,000.00
GEN14	CEA Technologies Inc./Dam Safety Interest Group	Membership	N44706	$9,905.00
GEN15	Assessment of "Reliability-based" Methodologies for use in PSES	Research	N44706	$4,041.00
GEN16	OSU Wave Energy Research	Research	N44706	$25,000.00
GEN17	PS66B, Gasification-Based Power Plant Development and Deployment	Membership	N44706	$51,128.00
GEN18	EPRI, River in Stream Energy Conversion (RISEC)	Membership	N44706	$0.00
			Totals	$307,725.00

UE 197
Attachment 269-B

Research and Development Budgets
For years 2008 and 2009

Funded Research Projects in 2008 – To Date (April / 2008) *

Project	Approved Funding	
N44706 Corporate R&D, Supply Energy		
OSU Wave Energy Research	20,000	
Finite Element Modeling to Decrease Repair Costs and Increase Reliability at PGE Hydro & Thermal Plants	25,000	
Canemah Bluffs Micro-Hydroelectric Feasibility Study	10,000	
Geothermal Investigation of PGE Leased Lands NE of Mt. Hood	15,000	
Boiler Life and Availability Improvement EPRI Target 63	29,882	
Collaborative Analysis of CO2 Policy Impacts on Western Power Markets EPRI tailored collaboration	5,000	
Development and Evaluation of Grid-Support Infrastructure Application for PHEVs – EPRI Target 18.012	8,564	
Multi-pollutant Technology Evaluations and Databases – EPRI Target P75.001	12,630	
Subtotal		121,076
N44707 Corporate R&D, Delivery System		
PNNL Real-Time Appliance Load Modulation **	25,000	
Exacter Outage Avoidance System	15,000	
Subtotal		40,000
N44708 Corporate R&D, Serve Customers		
Community Geothermal & Municipal Water Heat Exchange Program	35,000	
Plug-in Electric Vehicle Initiative – Charging Station Pilot Project **	10,000	
Subtotal		45,000
N44799 Corporate Membership		
GRIDAPP Utility Consortium Membership	50,000	
Subtotal		50,000
Total	**$256,076**	$256,076

* Approximately $40,000 remains in the $304,000 2008 R&D budget at this point in time

** Also funded at this level into 2009

Summation of Specific Topical Research Areas For 2009

R & D Research Area*	Sub-Total Cost	Total Cost ($)
Distributed Standby Generation		275,000
• Testing fuel additives to extend biodiesel shelf life in support of diesel applications		
• Testing of evolving IEEE standards for DSG applications on localized electrical networks		
• Protocol development and testing of DSG with AMI		
• PNNL Real-Time Appliance Load Modulation		
Distributed Energy Storage		
Plug-in Electric Hybrid Vehicles		
• Plug-in Electric Vehicle Initiative – Charging Station Pilot Project	10,000	
• Conversion of two hybrids w/ advanced battery	75,000	
• New EV with advanced battery	75,000	
• Joint Partnership w/ manufacturer	100,000	
Sub-total	260,000	260,000
Ice Storage demonstration	125,000	125,000
Highly Efficient Community-Scale Infrastructure		
• Solar-Ready Homes	50,000	
• Geothermal Heat Pump Community Loop	50,000	
• Municipal Water Coupled Heat Pump	125,000	
• Ductless Mini-Split Applications	60,000	
Sub-total	285,000	285,000
Infrastructure Reliability, Maintenance, Sustainability		150,000
• Extending power pole life through in-field inspection and treatment		
• Specific university level research into mechanisms that decrease pole life		

* Some of these projects will undoubtedly be funded on a multi-year basis (beginning 2009 and ending in 2010)

R & D Research Area*	Sub-Total Cost	Total Cost ($)
• Continuing research in minimizing our system infrastructure impacts on wildlife and local ecology		
• Updating PGE's very progressive forest management plan to include the latest management thinking		
• Testing and demonstrations for transmission and distribution upgrades that allow early failure detection and prevention		
Anticipating Carbon / Greenhouse Gas Regulation		
• Carbon Capture from Flue Gas	225,000	
• Biotic Capture & Storage from Flue Gas	75,000	
• Geologic Carbon Storage from Flue Gas	150,000	
• Other Biotic Carbon Storage Opportunities	150,000	
• Capture or mitigation of other GHGs	100,000	
• Tree Planting as an Ecological Service	50,000	
Sub-total	750,000	750,000
Renewable Power Or Highly Efficient Generation		150,000
• Testing "drop-off" sensitivity to grid frequency variation for solar photovoltaic inverters		
• Test and demonstration of various solar array, environmental conditions and energy storage combinations		
• Complimentarity assessments for co-located wind and solar powered resources		
• Compatibility and complimentarity studies of co-located eco-roofs and solar PV installations		
• Formal studies of physical and infrastructural limitations for large scale solar PV and solar hot water penetration in PGE's service territory		
Total		**$1,995,000**

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 802

Exhibits in Support of Surrebuttal Testimony

September 15, 2008

September 8, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated September 2, 2008
Question No. 447

Request:

a. **Please provide documentation demonstrating that PGE provided an explanation to Staff that they were using an erroneous number related to the budget amount provided by PGE in response to Staff's data request no. 269-B-2.**

b. **Please provide the date that PGE provided any information related to an explanation that Staff was using an erroneous number related to the R&D budget.**

c. **Please demonstrate how Staff ignored PGE's attempts to notify Staff that they were relying upon an erroneous number.**

Response:

a. PGE did not provide Staff with an erroneous number related to the budget amount for R&D projects. Attachment 447-A was provided to all parties at the settlement discussions on June 12 and June 13, 2008. **Attachment 447-A is confidential and subject to Protective Order No. 08-133.**

In addition, Exhibit 500, Page 8, discusses PGE's forecast of approximately $1.0 million in R&D costs. PGE Exhibit 501 lists $1 million. Staff/100/Owings/16, lines 10-18 refers to the $1 million R&D amount.

b. PGE discovered a discrepancy in both Staff (S-2) and CUB proposed settlement adjustments and addressed the topic at the June 12th and 13th settlement discussions with Staff and intervenors. PGE notified Staff and intervenors of the discrepancy and advised that PGE's Response to OPUC Data Request No. 269, Attachment B-2, provided a "summation of specific topical research areas" for 2009, and was not a specific budget calculation. PGE indicated through a footnote, that "some of the projects will undoubtedly be funded on a multi-year basis…". See also PGE's response to part (a).

c. In Staff's Direct Testimony, Staff Exhibit 104, dated July 9, 2008, Staff continued use of the $1,995,000 figure as PGE's 2009 budgeted amount, even though PGE informed parties of the error as discussed above. PGE then reiterated the discrepancy and difference in calculations through its Rebuttal Testimony, Exhibit 1900, Page 10, and Exhibit 1901 (PGE's Response to OPUC Data Request No. 269 Attachment B-2).

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CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 803

Exhibits in Support of Surrebuttal Testimony

September 15, 2008

Reconciliation of Incremental FTEs in UE 197 General rate Case

	FTEs		Sources: Exhibits	Staff DRs	CUB DRs	Other
Incremental FTEs per UE 197 Work Papers		130	800/5, Table 2		2, 3, 4	
FTE Adjustments:						
Heat pumps moved "below the line" (Outboard and Errata)		-4	200 WP and Errata			
Unfilled distribution (Outboard)		-20	200 WP		4	
Unfilled customer service (Outboard)		-10	200 WP		4	
FERC 890-A (Outboard)		7.5	400/15-16	103, 104, 167		
Additional FERC/NERC/WECC compliance costs (Errata)		7	500/24-25	103, 104		
Subtotal		-19.5				
Adjusted Incremental FTEs		110.5				
Drivers of FTE Increase:						
Covered in prior rate cases:						
Partial year 2007 to full year 2009 (from 12 FTEs to 23 FTEs) - Port Westward	11					UE 180, Order 07-015
Biglow Canyon	5	16		164		UE 188, Order 07-573
System growth - distribution		12	600/9-10	177		
Customer growth - customer services (in line with customer growth)		14	700/4			
Business growth						
Legal	3		501	224		
Governmental Affairs	1		501	224		
Contract Services/Purchasing	1		501	224		
Human Resources	1		501	224		
Finance and Accounting	1		501	224		
Other A&G	2		501	224		
Customer services	1		-			
Generation project managers - Boardman emission controls, Biglow 2 and 3	3		400/19			
Generator simulator at Boardman	2		400/18			
Power Operations	1		400/15	165		
IT	5	21	500/20			
Cost savings and efficiency - IT (CIS and WebSphere)		7	500/20	101, 264, 271, 273		
Compliance						
FERC 890-A	7.5		400/15-16	103, 104, 167		
Additional FERC/NERC/WECC compliance costs	7		500/24-25	103, 104		
Business Continuity and Emergency Management	4		500/13-14	103, 104, 172		
Environmental Services	3.5		501			
Transmission engineers	2	24	600/4	174		
Succession planning						
Transmission	1		600/4-5	175		
Boardman	1	2	400/18			
Generation Support						
Boardman Support	4		400/18	169		
Additional thermal, hydro, and wind generation support	11	15	400/18-19			
Total		111				

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 804

Exhibits in Support
of Surrebuttal Testimony

September 15, 2008

UE 197
PGE's Response to OPUC Data Request No. 203
Attachment 203-B

FTE by Employee Class

	Exempt	Hourly	Officer	Union	Grand Total
2002 Actual	1,165	564	15	852	2,596
2003 Actual	1,124	574	14	826	2,538
2006 Actual	1,169	573	14	798	2,554
2007 Actual	1,153	584	13	809	2,560
2008 Budget	n/a	n/a	n/a	n/a	2,692
2009 Forecast	n/a	n/a	n/a	n/a	2,733

FTE by Employee Class - (2008 and 2009 are Calculated Estimates)

	Exempt	Hourly	Officer	Union	Grand Total
2002 Actual	1,165	564	15	852	2,596
2003 Actual	1,124	574	14	826	2,538
2006 Actual	1,169	573	14	798	2,554
2007 Actual	1,153	584	13	809	2,560
2007 Ratio*	45%	23%	*	32%	
2008 Budget**	1,213	615	12	852	2,692
2009 Forecast**	1,232	624	12	865	2,733

* Officer totals are estimated separately for 2008 and 2009.

** PGE's response to OPUC Data Request No. 203 stated that PGE does not budget by employee class. PGE applied the ratios from 2007 actuals to the 2008 and 2009 forecasts in this attachment.

http://www.portlandgeneral.com/about_pge/regulatory_affairs/filings/data_requests/UE197/OPUC/docs/[DR_319_Attach_A.xls]OPUC DR 319 A

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 805

Exhibits in Support
of Surrebuttal Testimony

September 15, 2008

PGE Utility Full-Time Equivalents (FTE)
by Year, by Division

Utility Straight-Time Division	2005 Actual	2006 Actual	2007 Forecast	2008 Budget	2009 Test Year
Administrative and General	612	635	639	656	665
Customer Accounts	498	503	510	526	535
Customer Service	70	73	75	76	81
Generating - Beaver	64	57	53	54	54
Generating - Biglow	0	0	0	5	5
Generating - Boardman	69	70	74	77	81
Generating - Coyote	12	12	13	14	14
Generating - Other	221	238	244	248	260
Generating - Port Westward	0	0	10	19	19
Generating - Trojan	22	15	14	13	12
Transmission and Distribution	937	937	962	1,003	1,007
Total Utility Straight-Time	**2,504**	**2,540**	**2,594**	**2,692**	**2,733**

Utility Over Time Division	2005 Actual	2006 Actual	2007 Forecast	2008 Budget	2009 Test Year
Administrative and General	2	2	2	2	2
Customer Accounts	10	13	10	10	10
Customer Service	0	0	0	0	0
Generating - Beaver	2	3	3	3	3
Generating - Biglow	0	0	0	0	0
Generating - Boardman	8	8	10	10	10
Generating - Coyote	2	1	2	4	4
Generating - Other	2	4	5	2	2
Generating - Port Westward	0	0	2	4	4
Generating - Trojan	1	1	1	0	0
Transmission and Distribution	72	95	68	57	58
Total Utility Over Time	**97**	**126**	**103**	**92**	**93**
Total Utility FTE	**2,602**	**2,666**	**2,697**	**2,784**	**2,827**

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 806

Exhibits in Support
of Surrebuttal Testimony

September 15, 2008

SUMMARY OF COMPENSATION COST ($000)

Compensation category / program		2005 Actual	2006 Actual	2007 Forecast	2008 FOM	2009 Rate Cs
Benefit Compensation						
Health & Dental Plan		26,867	25,930	27,809	28,705	31,555
Employee Wellness Program		138	237	275	273	397
Health Reimbursement Account		1,203	1,454	1,615	1,815	1,531
Short Term Disability Insurance		227	314	404	476	634
Long Term Disability Benefits		1,487	(202)	1,505	1,355	1,358
Group Life Insurance		1,131	1,153	1,131	794	828
Employee Assistance Program		53	48	51	62	64
Retirement Savings Plan		14,593	12,224	13,620	14,228	14,656
Pension Plan	a	2	3,915	2,203	-	-
Education Plan		459	495	464	453	485
Recreation Program		23	19	13	25	26
Misc. Employee Benefits		191	163	319	395	544
Benefits Administration		347	409	497	341	427
Supp. Exec. Pension (SERP)	b	-	-	-	-	-
MDCP Pens/Savings Makeup	b	-	-	-	-	-
Benefit Compensation Total		46,722	46,158	49,904	48,923	52,505
Wages & Salaries						
Straight Time		164,989	172,818	181,765	198,410	209,610
Overtime		11,751	15,598	13,045	11,994	12,909
Wages & Salaries Total		176,741	188,416	194,810	210,404	222,519
Incentive Compensation						
Boardman Tmwrks (PGE share)		98	53	127	108	108
Coyote Springs (PGE Share)		193	286	141	168	174
Port Westward		-	-	349	277	285
Pelton CIP (PGE Share)		2	2	2	2	2
Trojan (PGE share of PGE O&M)		-	-	-	-	-
PGE CIP		3,563	3,720	6,606	5,150	5,983
Boardman ACI (PGE share)		55	36	69	60	60
Pelton ACI		21	54	(9)	17	17
Wholesale Marketing		588	751	1,583	906	933
PGE ACI		1,741	2,236	2,464	2,365	2,434
Officer ACI		1,357	1,087	4,260	1,686	1,737
Stock Incentive Plan		-	717	2,449	3,211	2,813
Notable Achievement Awards		193	256	314	200	200
Retention/Signing Awards		37	-	-	-	-
Miscellaneous Awards		-	-	365	27	27
Total Incentives		7,847	9,199	18,720	14,178	14,773
Total Compensation		**231,310**	**243,774**	**263,435**	**273,506**	**289,797**
				13,782		
a credits set to zero		4.44%	4.88%	9.61%	6.74%	6.64%

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 807

Exhibits in Support of Surrebuttal Testimony

September 15, 2008

Portland General Electric
UE 197/UE 198
Test period ending December 31, 2009
(000)

Staff proposes to adjust FTE count. Staff reviewed PGE's historical FTE level and compared it to the proposed level for 2009 test period. Staff proposes to normalize the growth of FTE in line with the historic levels as well as allowing an additionaly 26 FTE in acknowledgment of incremental programs.

Staff Proposed Workforce Adjustment

	PGE	Staff	Adjustment
PGE			
2009 FTE Count	2,733	2,635	(98)
			Workforce Adjustment
Wages & Salaries w/PTO	**$223,794**	**$212,545**	**($11,249)**
Percentage O&M	PGE/1403 per PGE rebuttal	71.75%	**($8,071)**
Percentage Capital - from Corp Incentives Worksheet		28.25%	**($3,178)**
Depreciation Adjustment	Gross Plant	5,173,537	
Annual Depreciation		175,781	
% Depreciation to RB		3.398%	**($108)**

Staff Initiator:
Carla Owings

Staff/807
Owings/1

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
WORKFORCE ADJUSTMENT WORKPAPERS

FTE by Employee Class
Straight Time Employees Only
Data Response 203-B and UE 180 DR

Class	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2007Budget UE180
Exempt	1,124	1,134	1,150	1,169	1,153	n/a
Hourly	574	574	570	573	584	n/a
Officer	14	13	13	14	13	n/a
Union	826	810	795	798	810	n/a
Grand Total	2,538	2,531	2,529	2,554	2,560	2,629
Adjusted for Trojan		22	25	15		15
		2,509	2,504	2,539	2,560	-2,614

Delta Employees Budget to Actual	**69**	Exhibit 800/wkp 8
Delta Employees Exhibit 800 to Actual	**128**	2688

2008 Budget	2009 Budget	
1,213	1,232	(2,560)
615	624	
12	12	
852	865	
2,692	2,733	

	2003 Actual	2004 Actual	2005 Actual (From Actuals above)	2006 Actual	2007 Actual	**Overall Average Change**
% Change						
Average Annual Change	**-2.29%**	**-0.28%**	**-0.08%**	**0.98%**	**0.23%**	**-0.29%**

3-Yr Average Change
0.38%

Staff Proposed Adjustment
1.45%

Staff Proposed Adjustment:

	Base Year of 2007 Actuals	PGE Proposed # of FTE	Impact of Additional FTE per PGE		
2007 Base Year FTE ST	2,560				
Adjust using 3 year Average	1.45%		222,944,010	2009 Total Comp.	See Table 1 Exhibit 800/2
2008 Budgeted FTE	2,597	2,692	425,000	Errata Filing	
Adjust using 3 year Average	1.45%		12,909,269	Overtime	See Table 1 Exhibit 800/2
2009 Budgeted FTE	**2,635**	75	210,459,741		
Staff Proposed Incremental FTE	**0**		48.50%	Loadings	
	2,635	2,733	312,532,715	Fully loaded	See Table 2 Exhibit 800/5
			2,733	2009 Budgeted FTE	
Disallowed Number of FTE	**98**		114,355	per Employee	
Fully Loaded Cost per Employee	**114,355**		77,007	w/out Loadings	
Staff Proposed Adjustment	**11,249,321**		37,348	PTO per Employee	

FTE Counts	
2,733	Original Request
2,706	PGE rebuttal testimony
27	
2,612	Staff's Original Proposa
2,635	Staff's Rebuttal
23	
2,706	PGE rebuttal testimony
2,635	Staff's Rebuttal
71	

Loadings per PGE Rebuttal Testimony PGE/1400/Tooman-Tinker/10/line 11

29.09%	Benefits	59.98%
9.27%	Payroll Taxes	19.11%
6.95%	Incentives	14.33%
3.19%	Employee Support	6.57%
48.50%	**Total Loadings**	

Staff Proposed FTE	2,635
PGE 2009 W&S adj to include Errata	**210,884,741**
Overtime	12,909,269
ted PGE proposed W&S (includes OT)	223,794,010

Staff Proposed W&S	$199,635,420		
Overtime	12,909,269	2,058,393	18 FTE
Staff Proposed W&S	**$212,544,689**	3,430,655	30 FTE

Incentive Portion of loadings=7.48%

2,597	CIP per employee
98	adjusted FTE
255,435	See Corp Incentive Adjustment S-4

(11,249,321) Workforce Adjustment

($11,249,321) check

-5.29% Percentage Adjustment

Staff/807
Owings/2

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 808

Exhibits in Support
of Surrebuttal Testimony

September 15, 2008

Staff/808
Owings/1

SUMMARY OF COMPENSATION COST ($000)

Compensation category / program		2005 Actual	2006 Actual	2007 Forecast	2008 FOM	2009 Rate Cs
Benefit Compensation						
Health & Dental Plan		26,867	25,930	27,809	28,705	31,555
Employee Wellness Program		138	237	275	273	397
Health Reimbursement Account		1,203	1,454	1,615	1,815	1,531
Short Term Disability Insurance		227	314	404	476	634
Long Term Disability Benefits		1,487	(202)	1,505	1,355	1,358
Group Life Insurance		1,131	1,153	1,131	794	828
Employee Assistance Program		53	48	51	62	64
Retirement Savings Plan		14,593	12,224	13,620	14,228	14,656
Pension Plan	a	2	3,915	2,203	-	-
Education Plan		459	495	464	453	485
Recreation Program		23	19	13	25	26
Misc. Employee Benefits		191	163	319	395	544
Benefits Administration		347	409	497	341	427
Supp. Exec. Pension (SERP)	b	-	-	-	-	-
MDCP Pens/Savings Makeup	b	-	-	-	-	-
Benefit Compensation Total		46,722	46,158	49,904	48,923	52,505
Wages & Salaries						
Straight Time		164,989	172,818	181,765	198,410	209,610
Overtime		11,751	15,598	13,045	11,994	12,909
Wages & Salaries Total		176,741	188,416	194,810	210,404	222,519
Incentive Compensation						
Boardman Tmwrks (PGE share)		98	53	127	108	108
Coyote Springs (PGE Share)		193	286	141	168	174
Port Westward		-	-	349	277	285
Pelton CIP (PGE Share)		2	2	2	2	2
Trojan (PGE share of PGE O&M)		-	-	-	-	-
PGE CIP		3,563	3,720	6,606	5,150	5,983
Boardman ACI (PGE share)		55	36	69	60	60
Pelton ACI		21	54	(9)	17	17
Wholesale Marketing		588	751	1,583	906	933
PGE ACI		1,741	2,236	2,464	2,365	2,434
Officer ACI		1,357	1,087	4,260	1,686	1,737
Stock Incentive Plan		**-**	**717**	**2,449**	**3,211**	**2,813**
Notable Achievement Awards		193	256	314	200	200
Retention/Signing Awards		37	-	-	-	-
Miscellaneous Awards		-	-	365	27	27
Total Incentives		7,847	9,199	18,720	14,178	14,773
Total Compensation		**231,310**	**243,774**	**263,435**	**273,506**	**289,797**
				13,782		
a credits set to zero		4.44%	4.88%	9.61%	6.74%	6.64%

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 809

Exhibits in Support of Surrebuttal Testimony

September 15, 2008

Portland General Electric
UE 197/UE 198
Test period ending December 31, 2009
(000)

Staff proposes to adjust PGE incentive program based on a three-year and five-year historical average of actual incentives paid as well as an adjustment to recognize work force adjustment.

Staff Proposed Adjustment for Corp Incentives

Staff Proposal		**$**	**(8,807,740)**
Proposed Staff Adjustment		**$**	**(8,808)**
Staff Adjustment to O&M for Corp Incentives			**(6,320)**
Staff Adjustment to Capital for Corp Incentives			**(2,488)**
Depreciation Adjustment			
Gross Plant	5,173,537		
Annual Depreciation	175,781		
% Depreciation to RB	3.398%		**($85)**

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
Corp Incentive Workpaper

	PGE/800 wkpaper 10	PGE/800 wkpaper 12	Delta
92.49%	$ 13,663,127	$ 14,773,000	$ 1,109,873

Officer ACI		1,736,870	PGE removes this completely....1500/3	2,601,486
Stock Incentive Plan		2,812,721	PGE/800/WP 12	1,132,765
Apply percentage reduction		92.49%		
Remove Officer CIP and Stock Incentive Plan		**$ 4,207,787**		
CIP and Teamworks less SIP and Officer ACI		**$ 9,455,340**		
Staff proposes Adjustment to remove 98 FTE		**$ 255,435**	See Corp Incentive Adjustment S-4-A	
Remaining CIP and Teamworks		**$ 9,199,905**		
Remove 50% of Remaining		**$ 4,599,952**		
TOTAL STAFF CORP INCENTIVE ADJUSTMENT		**$ (8,807,740)**		
Percentage O&M	71.75%	**$ (6,319,553)**		
Percentage Capital	28.25%	**$ (2,488,186)**		

PGE REMOVES THIS IN TESTIMONY			
1,736,870	Officer ACI	1500/3	
1,679,956	Stock Inc Plan	1500/3	Does not remove entire amount
3,416,826			
325,100	Directors Incentives	1500/3	These get taken out of Adjustment S-9
144,615	Misc & Other	1500/3	These get taken out of Adjustment S-9
3,886,541			

Class	2009 Budget
Exempt	1,232
Hourly	624
Officer	12
Union	865
Grand Total	2,733
Remove Officers	12
	2,721
Corp Incent $/employee	3,475

Incentive Portion of PTO
2545 per employee
121 adjusted FTE
307,959 See Corp Incentive
Adjustment S-4

Staff/809
Owings/2

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 810

Exhibits in Support of Surrebuttal Testimony

September 15, 2008

August 12, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE *First Supplemental* Response to OPUC Data Request
Dated May 20, 2008
Question No. 369

Request:

In reference to Staff's Data Request No. 244, Staff requested that PGE provide a reconciliation of FERC measures to PGE's estimated and booked costs for capital expenses related to Hydro facilities. The request was to include an explanation that demonstrated the differences between to the two estimates. In response, PGE provided two separate work papers that aggregated items with no possible way to compare the FERC mandates to the PGE projects and estimates. Please complete the response by providing the following:

a. **FERC mitigation measures (either from settlement agreements or from FERC license) item by item (I.e., FERC item no. 1, FERC item no.2), separated by capital and annual O&M (not in NPV form) costs.**
b. **Please explain in detail all significant variances between the FERC measures and PGE's estimates.**
c. **For Pelton-Round Butte, please provide how cost sharing is accomplished with joint licensee of which PGE is a 66.6% responsible party.**
d. **Please provide a copy and the amount of the original cost estimate for the Pelton-Round Butte SWW submitted in July of 2006 to FERC and recognized in August of 2006 by FERC within a settlement agreement. Please provide an explanation for the significant differences in the original cost estimate and the current cost estimates projected as of June of 2008.**
e. **Please provide an explanation for the differences between what was mandated by FERC for a SWW system and the project currently being constructed by PGE. What is the estimate of cost differences**

due to the changes between the FERC mandated system and the current project?

f. Please demonstrate what percentage of responsibility for the entire SWW facility has been borne by PGE to date, as well as what is projected to be borne by PGE upon completion of the project.

g. If PGE has provided upgrades to the SWW system, has PGE received approval from OPUC for upgrades to the SWW system that is above the project estimates mandated by FERC? If not, please demonstrate how ratepayers will benefit from these upgrades.

Initial Response (June 24, 2008):

a. FERC mitigation measures (either from settlement agreements or from FERC license) item by item (I.e., FERC item no. 1, FERC item no.2), separated by capital and annual O&M (not in NPV form) costs.

Attachment A is an Excel workbook that provides information on the Willamette Falls Project. The "Sum By Job" worksheet classifies and summarizes most of the information. The "Data" worksheet provides the FEA estimates. The "Notes" worksheet provides explanatory notes.

Attachment B is an Excel workbook that provides information on the Pelton Round Butte Project. The "Compare" worksheet classifies and summarizes most of the information. The "Data" worksheet provides the FEIS estimates. The "Notes" worksheet provides explanatory notes.

Attachment C is an Excel workbook that provides information on the Clackamas Project. The "Compare" worksheet classifies and summarizes most of the information. The "FEIS" worksheet provides the FEIS estimates. The "Notes" worksheet provides explanatory notes.

Attachment D provides information on funding requirements for the Pelton Round Butte Fund relevant to the "Compare" worksheet of Attachment B.

b. Please explain in detail all significant variances between the FERC measures and PGE's estimates.

See PGE's response to Part (a).

c. For Pelton-Round Butte, please provide how cost sharing is accomplished with joint licensee of which PGE is a 66.6% responsible party.

When the Pelton Round Butte Operating Trust was formed, PGE set up a new and separate bank account for the Trust. Co-owners, including PGE, are responsible for depositing their shares of any funding request into that account. As the funds are received they are withdrawn and transferred into a PGE account, where all costs are paid. Each month the bank reconciliation is provided to the co-owners.

In order to accurately account for costs incurred for the Trust, a specific entity was set up in PGE's general ledger system. All costs are properly recorded with this entity and monthly expenditure reports are issued to the co-owners and yearly reports to the auditors. The ledger J14911 for the trust account represents either over- or under-funding at any specific point in time. Various Funding requests are issued in accordance with the contract (weekly, semi-weekly, etc).

Attachment 369-E provides documentation on the implementation of the trust structure, specifically for December 2007. The funding requirements for PGE are 66.67 % of the totals. This same allocation was applied to all funding requirements. Attachment 369-E is confidential and subject to the protective order in this docket (Order No. 08-133).

d. Please provide a copy and the amount of the original cost estimate for the Pelton-Round Butte SWW submitted in July of 2006 to FERC and recognized in August of 2006 by FERC within a settlement agreement. Please provide an explanation for the significant differences in the original cost estimate and the current cost estimates projected as of June of 2008.

Clarification with Staff indicated that the request intended to ask about events in July and August of 2004, rather than 2006. The settlement did not mandate any particular design for the SWW. Instead, it required that whatever PGE eventually built needed to provide "safe, timely, and effective" fish passage and to meet certain agreed upon physical criteria (for example, certain velocities at the screens) and certain biological standards (percentage survival rates). The settlement agreement also required that PGE obtain approval from fish agencies on final designs.

FERC adopted all major components of the settlement agreement in the license (FERC License No. 2030, issued June 21, 2005). This license does not mandate a specific "SWW structure." However, the license includes conditions mandated by the U.S. Fish and Wildlife Service and the National Marine Fisheries Service. The conditions required by these agencies are virtually identical. Attachment 369-F is a copy of the National Marine Fisheries Service version of the conditions.

The conditions (known as Section 18 Fishway Prescriptions) contain three basic elements:

- Requirement that the Pelton Round Butte Licensees construct fish passage facilities that provide "safe, timely, and effective" fish passage,
- Specific engineering and biological criteria that must be met by the fish passage facilities, and
- Process steps that must be followed and approvals that must be achieved before the facilities can be built.

The conditions do not, in and of themselves, require a particular design to be used. Instead, they require that the Licensees propose and seek approval from fisheries agencies and FERC of structures that will provide safe, timely, and effective fish passage and that will also meet the specific engineering and biological criteria detailed in the license conditions.

See Response to Part (e) for cost comparisons.

e. **Please provide an explanation for the differences between what was mandated by FERC for a SWW system and the project currently being constructed by PGE. What is the estimate of cost differences due to the changes between the FERC mandated system and the current project?**

See Response to Part (d) for context.

Attachment 369-G provides a pictorial history of the SWW's design evolution. It also provides a comparison of the October 2006 and October 2007 cost estimates for the design that is being implemented, shown in the lower right corner of the pictorial history. In addition, this attachment lists the primary drivers for the cost increase from October 2006 to October 2007. At the time of the settlement agreement discussed above, our focus was on the cheese-wheel design, shown in the lower left hand corner of the pictorial history. The 25% design estimate (after 25% of design work completed) for the cheese wheel design was $87 million in 2004. This figure is for 100% of the project; PGE's share would be $58 million. This estimate is not directly comparable to the estimate for the current design that is under construction. At the 25% design stage, not all issues have been identified and the costs associated with the not yet identified issues are not included in the 25% design stage cost estimate.

Attachment 369-H provides a narrative explanation of what the SWW must accomplish, why a switch was made from the cheese wheel to the current design, and detail on the primary drivers of the cost increase from October 2006 to October 2007 shown in Attachment 369-G. The detailed cost increases are for 100% of the project. PGE's share would be two-thirds.

f. **Please demonstrate what percentage of responsibility for the entire SWW facility has been borne by PGE to date, as well as what is projected to be borne by PGE upon completion of the project.**

See Response to Part (c). PGE has borne a two thirds share of the SWW costs to date and will bear this same share through project completion. Attachment 369-I shows that PGE's share of expenditures was 66.67% in 2006. This same share has applied for all expenditures to date. Attachment 369-G, which focuses on how SWW cost estimates have increased over time, includes an October 1, 2007, estimate of SWW project costs. Specifically, Page 2 of that attachment projects $108,392,000 for 100% share costs, and $72,623,000, or 67%, for PGE. For this summary projection, the 66.67% was rounded to

67%. Note that the PGE share cost estimate contained in Attachment 316-E to PGE's Response to OPUC Data Request No. 316, $73,557,000, is more definitive than the figure contained in Attachment 369-G, whose purpose (along with the 100% share projection) is to demonstrate that we project PGE's share of expenditures through project completion to be two-thirds.

g. **If PGE has provided upgrades to the SWW system, has PGE received approval from OPUC for upgrades to the SWW system that is above the project estimates mandated by FERC? If not, please demonstrate how ratepayers will benefit from these upgrades.**

As stated in PGE's Response to Part (d), neither the settlement agreement nor the license mandated a specific "SWW design." PGE cannot receive approval for "upgrades" or any other part of rate base additions prior to their placement in service. An asset must be used and useful before it can become part of rate base.

The SWW must meet the Fishway Prescriptions discussed in PGE's Response to Part (d). Changes in design to meet these prescriptions benefits customers because it allows production of power for customers at costs that are substantially below those of market power purchases or other power supply alternatives. If PGE did not take necessary actions to meet the Fishway Prescriptions, this low-cost power supply resource would **not** be available to customers.

First Supplemental Response (August 12, 2008):

In addition to the material provided in PGE's Response to Parts (d) and (e) of OPUC Data Request No. 369, OPUC Staff has verbally requested additional documentation concerning how PGE negotiated less costly license measures during settlement negotiations concerning the Pelton Round Butte Project and how PGE has negotiated with other parties to implement license requirements in less costly ways.

Attachment 369-J to this First Supplemental Response discusses nine examples of PGE negotiating less costly Pelton Round Butte license requirements. Attachment 369-K discusses cases in which PGE negotiated less costly implementation of Pelton Round Butte license requirements. Attachment 369-K is confidential and subject to Protective Order No. 08-133. Attachment 369-L is a license amendment application that provides additional documentation for Attachment K. Given its size, Attachment 369-L is only provided electronically.

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 811

Exhibits in Support of Surrebuttal Testimony

September 15, 2008

Pelton Round Butte

Capital	Description	PGE Job(s)	PGE Share Estimate at Time of FEIS (2002)	Actual 2003	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Budget 2008	Forecast 2009	Sum Actual/Forecast	Projected 2010-2020	Total (Through 2020)	Delta From FEIS	Explanation of Delta
In FEIS															
	PRB PME -Operations Compliance Plan	23525		0	0	12,230	43,087	29,753	0	0	85,071	-	85,071		
	PRB PME -Install/Upgrade Lake Level Monitoring Instrum	22721		0	0	81,390	3,633	6,009	0	0	91,033	-	91,033		
	Project Operations Compliance (Total)		283,173										-	(107,070)	
	Fish Health Management Program	24952	66,667	0	0	0	0	0	218,843	225,205	444,048	933,333	1,377,381	1,310,715	Cost unknown at time of FEIS.
	Hatchery Improvements/RB Hatchery AOP	22825	346,300	0	0	541	200,370	53,538	0	0	254,449	-	254,449	(91,851)	
	Lower River Gravel Study Plan	22730	116,667	0	0	36,520	26,122	(62,661)	0	0	(19)	1,236,667	1,236,647	1,119,981	Cost unknown at time of FEIS.
	Large Wood Management Plan	22762	6,667	0	0	10,170	10,666	(20,836)	0	0	0	0	0	(6,667)	
	Lower River Habitat Enhancement Plan	22727	313,233	0	0	43,658	43,040	81,862	328,764	449,659	946,983	0	946,983	633,750	Costs of construction have increased significantly since 2
	Pelton Round Butte Fund (General)	22771		0	0	11,274	35,171	59,986	0	0	106,431	16,867,401	16,973,832		Amount in Settlement Agreement was much higher than I
	PRBF 2006-10 - Crooked River Pump Screen Replacement	24435		0	0	0	0	63,365	0	0	63,365		63,365		Cost unknown at time of FEIS.
	PRBF 2007-05 Corbett's Jack Creek Water Conservation Project	25089		0	0	0	0	41,571	0	0	41,571		41,571		Cost unknown at time of FEIS.
	PRBF - 2007-07 Flymon Stewardship Program	25093		0	0	0	0	40,020	0	0	40,020		40,020		Cost unknown at time of FEIS.
	PRBF - 2007-09 Whychus Creek Dispersed Camping Project	25094		0	0	0	0	15,608	0	0	15,608		15,608		Cost unknown at time of FEIS.
	PRBF 2007-10 Metolius River Fish Habitat Enhancement	25095		0	0	0	0	96,668	0	0	96,668		96,668		Cost unknown at time of FEIS.
	PRBF 2007-11 Whychus/Lake Creek Passage & Screening Phase 1	25097		0	0	0	0	152,630	0	0	152,630		152,630		Cost unknown at time of FEIS.
	PRBF 2007-12 Whychus Creek Restoration @ Camp Polk	25098		0	0	0	0	212,389	0	0	212,389		212,389		Cost unknown at time of FEIS.
	PRBF 2007-13 TSID Fish Screening and Passage - Phase 1	25103		0	0	0	0	2,181	0	0	2,181		2,181		Cost unknown at time of FEIS.
	PRBF 2007-14 Lake Creek Culvert Removal Project	25104		0	0	0	0	1,681	0	0	1,681		1,681		Cost unknown at time of FEIS.
	PRBF 2007-15 Metolius Streamside Protection Project	25105		0	0	0	0	14,837	0	0	14,837		14,837		Cost unknown at time of FEIS.
	PRBF 2007-16 Trout Creek Watershed Restoration Project	25106		0	0	0	0	316,825	0	0	316,825		316,825		Cost unknown at time of FEIS.
	PRBF 2007-17 LCR Fish Passage (Peoples Irrigation District)	25107		0	0	0	0	170,869	0	0	170,869		170,869		Cost unknown at time of FEIS.
	PRBF 2007-18 LCR Fish Passage (Crooked River Central)	25108		0	0	0	0	326,777	0	0	326,777		326,777		Cost unknown at time of FEIS.
	PRBF 2007-20 Stearns Dam Removal	25109		0	0	0	0	54,027	0	0	54,027		54,027		Cost unknown at time of FEIS.
	PRBF 2007-21 Coyote Creek Watershed Restoration Project	25110		0	0	0	0	21,961	0	0	21,961		21,961		Cost unknown at time of FEIS.
	PRBF 2007-23 Shitike Creek Restoration Project	25111		0	0	0	0	133,400	0	0	133,400		133,400		Cost unknown at time of FEIS.
	PRBF 2007-27 Community Restoration & Watershed Education	25112		0	0	0	0	29,209	0	0	29,209		29,209		Cost unknown at time of FEIS.
	PRBF 2007-01 McKay Creek Culvert Replacements	25136		0	0	0	0	70,035	0	0	70,035		70,035		Cost unknown at time of FEIS.
	2007-03 Trout Creek Passage and Habitat Enhancement	25137		0	0	0	0	0	0	0	-		-		Cost unknown at time of FEIS.
	PRBF 2007-24 Warm Springs Reservation Watershed Maintenance	25138		0	0	0	0	31,700	0	0	31,700		31,700		Cost unknown at time of FEIS.
	Pelton Round Butte Fund (Total)		3,902,507											14,867,078	See above individual component explanations.
	Trout Creek MOU	24920	400,407	0	0	0	0	0	292,130	418,504	710,634	0	710,634	310,228	Cost unknown at time of FEIS.
	Construct Selective Water Withdrawal	22798	9,174,580	0	0	835,483	2,143,496	21,020,163	40,589,980	9,038,768	73,627,891	0	73,627,891	64,453,311	Cost unknown at time of FEIS. See detail in PGE's Resp
	Pelton/Round Butte PME -Fish Passage	22723		0	0	384,198	566,291	720,399	557,844	194,558	2,423,290	0	2,423,290		Cost unknown at time of FEIS.
	PRB PME - Purchase 3/4 Ton 4x4 Trucks	22725		0	0	32,237	14,064	32,207	130,065	0	208,574	0	208,574		Cost unknown at time of FEIS.
	PRB PME - Purchase Drift Boat and 21' Jet Boat	22729		0	0	5,829	0	33,283	0	0	39,112	0	39,112		Cost unknown at time of FEIS.
	PRB PME -Design & Construct Adult Release Facility	22800		0	0	158	0	3,056	57,958	60,220	121,393	0	121,393		Cost unknown at time of FEIS.
	Round Butte PME -Construct Fish Trap at Tailrace Jump Pool	22821		0	0	1,921	0	(127)	5,225	5,469	12,488	0	12,488		Cost unknown at time of FEIS.
	PRB PME - Purchase Water Quality Monitoring Equipment	22826		0	0	55,516	4,033	0	0	0	59,549	0	59,549		Cost unknown at time of FEIS.
	Pelton Re Reg PME -Design & Construct Lower River Release Facility	23418		0	0	0	0	3,311	156,448	0	159,759	0	159,759		Cost unknown at time of FEIS.
	Pelton PME -Reestablish Weir at Mouth of Willow Creek	23469		0	0	0	0	0	21,171	22,013	43,184	0	43,184		Cost unknown at time of FEIS.
	PRB PME -Lamprey Passage Evaluation & Mitigation Plan	23523		0	0	0	(35,865)	(3,490)	0	0	(39,355)	0	(39,355)		Cost unknown at time of FEIS.
	PRB PME - Intake Structure Strobe Lights	24417		0	0	0	37,708	17,218	4,836	4,995	64,757	0	64,757		Cost unknown at time of FEIS.
	PRB PME - Install Permanent Forebay Exclusion Boom	24834		0	0	0	0	91,192	0	0	91,192	0	91,192		Cost unknown at time of FEIS.
	PRB PME - Design & Construct RB Tailrace Release Facility	24935		0	0	0	0	996	156,448	0	157,444	0	157,444		Cost unknown at time of FEIS.
	PRB PME - Round Butte Hatchery 8-inch Fish Pump	24950		0	0	0	0	0	30,682	31,265	61,947	0	61,947		Cost unknown at time of FEIS.
	PRB PME - Fisheries Boat Hull Replacement	24951		0	0	0	0	0	11,339	11,554	22,893	0	22,893		Cost unknown at time of FEIS.
	PRB PME - Upgrade Pelton Fish Trap	24974		0	0	0	0	0	68,815	71,120	139,935	0	139,935		Cost unknown at time of FEIS.
	Construct Fish Passage Facilities and Supporting Fish Passage Activities (Total)		226,667											3,339,497	Costs unknown at time of FEIS
	Habitat Measures on Federal Lands		0									0	-	-	
	Water Quality Management Plan		34,507									0	-	(34,507)	Done under O&M
	Total Aquatic		**14,871,373**												
	PRB PME - Terrestrial Resources	22559		-	-	79,347	152,603	56,176	180,543	175,194	643,863	929,333	1,573,197		Cost unknown at time of FEIS; license obligation.
	PRB PME - Terrestrial Resources	22941									-				Job 22941 not used.
	Terrestrial Resources Management Measures (Total)		**4,871,067**											(3,297,870)	Cost unknown at time of FEIS.
	PRB PME - USFS/BLM Campground Improvements	24213		0	0	0	0	34,156	0	417,480	451,636	286,667	738,303		
	PRB PME - Indian Park Improvements	24214		0	0	0	0	14,741	0	9,991	24,732	0	24,732		
	PRB PME - Pelton Park Campground Improvements	24215		0	0	0	2,661	21,078	0	0	23,739	234,667	258,406		
	PRB PME - Pelton Wildlife Overlook Improvements	24216		0	0	0	0	14,442	0	17,576	32,018	13,333	45,352		
	PRB PME - Round Butte Overlook Improvements	24217		0	0	0	0	1,314	0	0	1,314	0	1,314		
	PRB PME - Trout Creek Improvements	24218		0	0	0	0	68,689	0	0	68,689	0	68,689		
	PRB PME - OPRD Day Use Area Improvements	24219		0	0	0	0	83,375	0	68,673	152,048	906,667	1,058,715		
	PRB PME - Navigational Hazard Remediation	24220		0	0	0	0	0	0	0	-	0	-		
	Recreation Resources Implementation Measures (Total)		803,960											1,391,549	Cost of capital improvements significantly higher than ori
	Emergency Communications Study Plan	22835	0	0	0	68,677	196,587	124,566	0	0	389,830	0	389,830	389,830	Cost unknown at time of FEIS.
	Recreational User Surveys		0									0	-	-	
	Integrated Interpretation & Education Measures	22722	50,000	0	0	105,936	138,979	156,343	0	31,380	432,639	0	432,639	382,639	Cost unknown at time of FEIS.
	Tribal Officer for Warm Springs		0												
	Funding of Haystack Reservoir	Future expenditure	3,133									6,667	6,667	3,533	Cost unknown at time of FEIS.
	Funding of BLM Lower River Rec Sites	Future expenditure	27,867									90,667	90,667	62,800	Cost unknown at time of FEIS.
	Total Recreation		**884,960**												
	Shoreline Management Measures	24934	0	0	0	0	0	25,914	0	96,235	122,149	0	122,149	122,149	Cost unknown at time of FEIS.
	Shoreline Erosion Measures	24910	33,407	0	0	0	0	5,667	0	399,479	405,146	733,333	1,138,480	1,105,073	Cost unknown at time of FEIS.
	Project Road Maintenance	23402	83,520			27,000	40,000	25,000	726,000	1,068,000	1,886,000	-	1,886,000	1,802,480	Cost unknown at time of FEIS.
	Project Road Maintenance Measures FS		30,587									0	-	(30,587)	Cost unknown at time of FEIS.
	Project Road Maintenance Measures Jefferson Co.		0									0	-	-	
	Travel & Access Mgmt Plan	Future expenditure	3,333									3,333	3,333	-	
	Landscape Mangement Plan		0									0	-	-	
	Aesthetic Resources Protection Measures	23609	80,000	0	0	0	1,349	(1,349)	0	0	-	80,000	80,000	-	
	Total Land Use		**230,847**												
	Cultural Resources Management Measures	23610	**93,787**	0	0	0	20,192	(33,695)	0	0	(13,503)	0	(13,503)	(107,290)	Cost unknown at time of FEIS.
	Total FEIS Measure-Related		**20,952,033**											87,618,771	
Not in FEIS															
	Pelton-Round Butte Hydro Relicensing Project -- Original Job	14174		1,187,268	962,314	285,251	33,080	(23,122)	0	0	23,893,825	0	23,893,825		Not included in FEIS. Initial job set up to track co
	Pelton-Round Butte Fish Passage	18708		541,000	1,671,000	(39,902)	(940)	0	0	0	7,325,589	0	7,325,589		Not included in FEIS. Job established to capture
	Rd Butte-Install Erosion Control at Chinook Island	19673		0	290,232	0	0	0	0	0	338,267	0	338,267		Not included in FEIS.
	PGE Only- Pelton/Rd Butte Relicense Project	21800		0	0	0	130,600	0	0	0	130,600	0	130,600		Not included in FEIS.
	Trout Creek- Install 1 Mile of Fencing	21896		0	0	0	0	0	0	0	-	0	-		Not included in FEIS.

PRB PME - Modify/Repair L&S Workboat	24235		0	0	0	0	9,900	0	0	9,900	0	9,900	Not included in FEIS.
PRB PME - Mapping/GIS Evaluation	24919		0	0	0	0	0	58,629	55,034	113,663	0	113,663	Not included in FEIS.
PRB PME-Project Boundary Survey	23950		0	0	0	121,803	91,073	0	0	212,876	0	212,876	Not included in FEIS.
Total			1,728,268	2,923,546	2,037,435	3,928,732	24,535,882	43,595,721	12,872,374	118,273,458	22,322,067	140,595,526	
	Check	0	0	0	0	0	0	0	0	0			

BDS did not originally include -- factor in reconciliation with Response to 221
Not included in FEIS

Was included in DR 221 response (corrected by DR 368 response), but will not occur. For smaller amounts, 2009 cap. add's for UE 197 developed by escalating 2008 figures.

O&M		PGE Share Estimate at Time of FEIS (Annual 2002 $)	Actual 2003	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Budget 2008	Forecast 2009	Expected in Future (Annual Amount)		Explanation of Annual Delta
Not in FEIS												
RP404	Jefferson County Law Enforcement	See RP426	-	-	-	-	124,931	203,723	247,001	166,667	In 2010, escalating at 2.5 % per year.	
RP201	FERC Fees C81611 & J43612 -- Not in FEIS	491,025	-	-	-	507,228	481,346	534,134	556,211	598,266	In 2010, escalating at 1.6 % per year.	FERC fees are higher than originally anticipated.
RP410	USGS Stream guage program C81611 PN		-	-	-	10,721	11,592	12,540	13,540			
RP411	USGS Stream guage program C81611 RB		-	-	-	38,275	41,074	44,422	48,024			
	Total Stream Guage -- Not in FEIS	50,285								61,267	In 2010, escalating at 5.2 % per year.	
In FEIS												
RP416	Water quality monitor: RC 841 $10k RPMES RSPWQ, RC 172 $26k in job RWQ00	69,020	-	-	-	54,175	81,184	78,466	80,089	54,667	In 2010, escalating at 2.5 % per year.	
RP420	Fisheries including ODFW payments for hatchery O&M; plus operation of fish transfer facility	291,713	-	-	-	337,527	365,983	425,414	466,499	333,333	In 2010, escalating at 2.5 % per year.	Includes expanded incubation capacity and cost of ODF&'
RP421	Native fish monitor program (includes Screw traps at RB)		-	-	-	74,698	123,248	141,097	156,846	110,000	In 2010, escalating at 2.5 % per year.	
RP422	Terrestrial resources	209,853	-	-	-	40,677	62,508	87,292	104,902	73,333	In 2010, escalating at 2.5 % per year.	Some measures no longer required.
RP423	Terrestrial interim measures											
RP424	Recreation Plan/Trout Creek		-	-	-	2,867	14,674	42,753	65,937	44,667	In 2010, escalating at 2.5 % per year.	Not anticipated in FEIS.
RP425	Recreation resources	155,947	-	-	-	91,879	85,066	132,418	140,621	96,667	In 2010, escalating at 2.5 % per year.	
RP426	Emergency Communications	46,193	-	-	-	7,964	4,304	2,940	3,045	-	Done	
RP427	Interpretation and Education Plan (I&EP)	17,120	-	-	-	540	-	21,493	21,820	14,667	In 2010, escalating at 2.5 % per year.	
RP428	P/RB shoreline management plan	17,253	-	-	-	-	74,890	62,054	64,637	66,667	Per year through 2015, then 50,000 per year through 202	Actual cost of implementing shoreline plan more than anti
RP429	SHORELINE Erosion PLAN	4,140	-	-	-	-	9,147	13,695	47,240	3,333	In 2010, escalating at 2.5 % per year.	
RP430	Aesthetic Resources	0	-	-	-	-	4,889	7,276	7,523	5,333	In 2010, escalating at 2.5 % per year.	
RP431	Jeff Co. Road and FS roads	100,900	-	-	-	-	4,638	237,976	238,339	160,000	In 2010, escalating at 2.5 % per year.	Cost of construction and materials have increased.
RP432	Historic properties, cultural resources	21,800	-	-	-	39,768	103,115	131,579	136,454	60,000	In 2010, escalating at 2.5 % per year.	More cultural surveys than originally anticipated. Survey
RP433	Gravel Study	5,500	-	-	-	-	164,688	170,124	151,211	-		License obligation. Cost was unknown at time of FEIS. \
RP434	Pelton Round Butte PMEs - Large Wood Management	6,667	-	-	-	-	34,687	43,427	31,262	30,000	In 2010, escalating at 2.5 % per year through 2016.	License obligation. Cost was unknown at time of FEIS.
RP435	Pelton Round Butte PMEs - Fisheries - Trout Creek Habitat Enhancement		-	-	-	20	-	-	-	10,000	In 2010, escalating at 2.5 % per year through 2016.	
RP436	Pelton Round Butte FUND	0	-	-	-	-	-	12,336	12,864	4,000	In 2010, escalating at 2.5 % per year through 2016.	
RPS16	Pelton Round Butte PMEs - Fish Passage									13,333	In 2010, escalating at 2.5 % per year through 2016.	
RPS18	Pelton Round Butte PMEs - Fish Passage	45,187	-	-	-	-	99,386	126,937	947,624	666,667	In 2010, escalating at 2.5 % per year through 2016.	Cost of maintaining and operating fishways and operation
RTROU	Trout Creek		24,299	24,480	14,558	1,335	382	-	-			
	Trout Creek MOU -- not unitl 2010	10,353								21,013	In 2010, escalating at 2.5% per year	
	Project Operations Compliance	1,203,313								20,000	In 2010, escalating at 2.5% per year	Several FEIS measures were not required in the final lice
	Maintenance of SWW Structure -- not until 2009	819,693								See note		Budget for 2009 currently under preparation. Two compo
	Habitat Measures on Federal Lands -- Not Required	853,333								-		This FEIS measure not required. Therefore, costs will no
	Tribal Officer for Warm Springs -- Not Required	33,333								-		This FEIS measure not required. Therefore, costs will no
	Total	4,452,630	24,299	24,480	14,558	1,207,675	1,891,731	2,532,096	3,541,688			
	Check	0	0	0	0	0	0	0	0			

Staff/811
Owings/2

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 812

Exhibits in Support of Surrebuttal Testimony

September 15, 2008

Portland General Electric
UE 197/UE 198
Test period ending December 31, 2009
(000)

Staff Proposed Capital Expenditures Adjustment

	PGE	Staff	Adjustment	Projected Date
Remove Sel Water Withdraw	80,810,000	0	(63,974,583)	March 31, 2009
Remove Boardman Costs	6,986,000	0	(4,948,417)	April 30, 2009
Remove Boardman Costs	17,202,000	0	(7,884,250)	July 31, 2009
Remove Boardman Costs	11,812,000	0	(492,167)	December 31, 2009
Remove Clackamas Relicensing	65,203,000	0	(9,451,000)	December 31, 2009
2009 Cap Ex close to book	182,013,000	0	(86,750,417)	
Total Proposed Adjustment			**(86,750)**	

Staff proposed RB Adjustment
Depreciation Adjustment

Gross Plant	5,173,537	**(2,719)**	Original Depreciation Estimate
Annual Depreciation	175,781	**(92)**	Remove Dep Attributable to Clack
% Depreciation to RB	3.398%	**(229)**	Add Dep provided by PGE at Exhibit 1401
		(2,856)	

Relevant Testimony: PGE/400/20-22
Relevant Staff Data Requests: 221, 244, 245, 283, 368, 369, 370, 403, 404, 408
Staff Initiator:
Carla Owings

Staff/812
Owings/1

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 813

Exhibits in Support of Surrebuttal Testimony

September 15, 2008

DEX Portland

Staff/813
Owings/1

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☆☆☆☆☆ not yet rated

B Portland General Electric Company Energy Efficiency Energy Experts
121 SW Salmon St Portland, OR 97204-2904
0.54 miles from the center of Portland, OR
(503) 612-3500
☆☆☆☆☆ not yet rated

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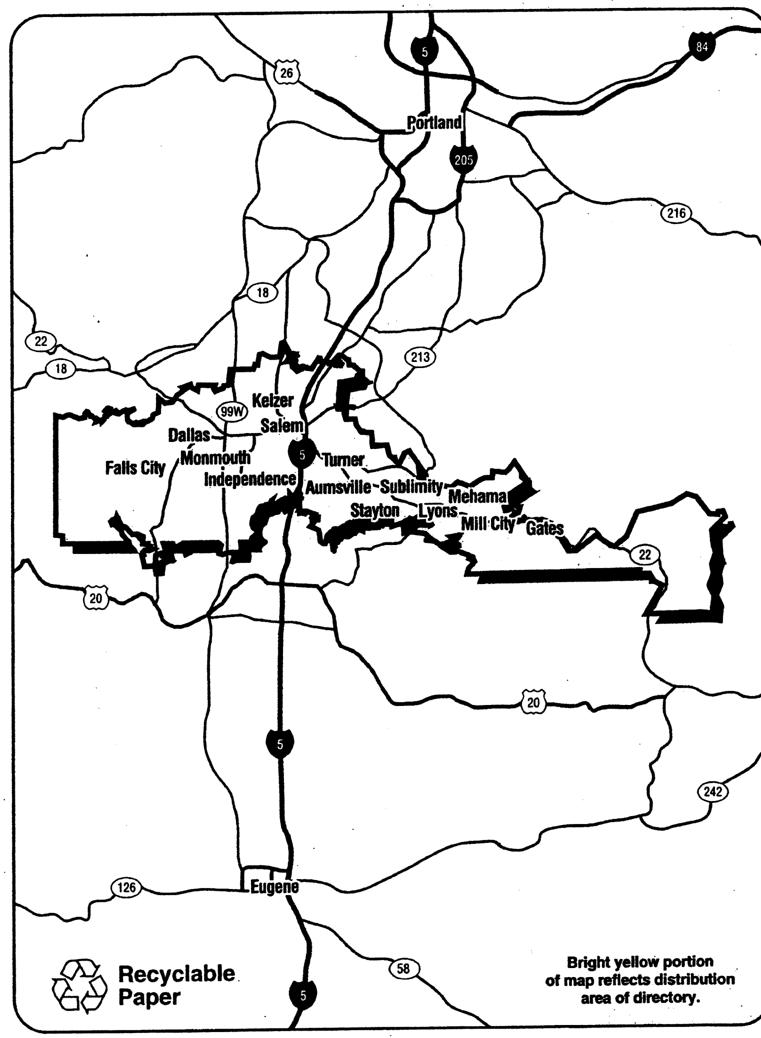

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Polinsky Mary 4265 State St Salem 97301 503 585-1649
Polishchuk Alexander
5712 Candy Flower Ct SE Salem 97306 503 316-0834
Pavel 1875 Yvonne St SE Salem 97306 503 589-9270
Polisson W F 4955 Centurian Ct S Salem 97302 503 540-0483
Politilo Vasiliy 4757 Welsh SE Salem 97317 503 371-7878
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Polito J 3756 Sunnyview Rd NE Salem 97305 503 585-8157
Politylo Galyna 4083 Market NE Salem 97301 503 399-2049
Polivka Dick & Beverly 503 581-2760
D M 503 581-4911
Polk Adolescent Day Treatment Center
2200 E Ellendale Ave Dllas 97338 503 623-5588
Polk City Directories Toll Free '1' 866 414-7848
Polk Community Development Corp
657 Main Dllas 97338 503 831-3173
Polk County Adult & Family Services 503 623-8118
Polk County Fire District No 1
Fire & Medical Emergencies Dial
Non Emergency Business 1800 Monmouth Indpndnce 97351 503 838-1510
Burn Information 503 838-2020
Polk County Historical
520 S Pacific Hwy W Rckrl 97371 503 623-4089
Polk County Housing Authority
1947 Salem-Dallas Hy NW Salem 503 585-1380
Polk County Museum & Historical Society
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Polk County Soil & Water Conservation
580 Main Dllas 97338 503 623-9680
Polk H M 503 362-8365
Polk Halo 429 E Main Mnmth 97361 503 606-4256
Polk J 503 363-9476
Polk Job And Career Center
580 Main St Suite B Dllas 97338 503 831-1950
Polk M 4575 Lark Ct NE Salem 97301 503 588-7469

POLK VETERINARY CLINIC
1590 E Ellendale Dallas 97338....503 623-8318

Polk Wendy 525 SW Cherry Dllas 97338 503 623-8381
Polka Cynthia 3603 Sunnyview Rd NE Salem 97305 503 370-8219
Polka Dot's Thrift Store 761 Main 503 623-6163
Polkhovskiy Aleksey 5286 Snowflake SE Salem 97306 503 363-9536
Pollak Diana 2948 Mapleleaf Ct NW Salem 97304 503 566-5986
Pollak Ruben Dpm 503 363-9992

POLLAK RUBEN DPM FACFAS
1365 North 10th Ave Stytn 97383 **503 769-7960**

Pollan Karen 1246 Lottie Ln NW Salem 97304 503 364-0551
Pollard Ardis 730 Browning Ave SE Salem 97302 503 378-7732
Daniel 503 391-6755
James 10885 Briedwell Rd Dllas 97338 503 623-8678
Polley Craig 4658 Goldenrod Av NE Salem 97305 503 390-3348
Jas W 734 Vinyard Ave NE Salem 97301 503 363-4958
Pollino John 5584 Mark Ct SE Salem 97317 503 399-8678
John E 1011 Commercial St NE Suite 210 Salem 97301 503 581-1501
Garrett Hemann Robertson Jennings Comstock & Trethewy PC Attys
Pollman Jennifer 548 Inverness Dr SE Salem 97306 503 585-3653
Pollock J Stytn 97383 503 769-4303
William & Sue 358 Dearborn Ave N Keizer 97303 503 463-4829
Pollock-Roop Jackie 503 390-8164
Pollok Donald 5639 Springwood Ave SE Salem 97306 503 581-2622
Pollreisz M L 321 W Virginia St Stytn 97383 503 769-2516
Polly David & Margaret
906 Blackbird Ct NE Salem 97301 503 362-7466
Polo Ridge Farms 8360 Helmick Rd Mnmth 97361 503 838-5704
Polsfoot David 2550 Lancaster Dr NE Salem 97305 503 585-4171
Polson L M 503 581-7984
Polston James 503 378-1513
Judith 503 363-7649
Marliee 1729 N 3rd Ave Stytn 97383 503 767-2033
S 503 585-4261
Terry 503 585-3108
Polvi Kelly 503 584-0502
Michael & Kelly 503 363-9552
P K 503 587-9073
Robert L & Vi 7960 Wallace Rd NW Salem 97304 503 391-6165
Robert & Viola 503 364-9754
S M 503 399-7084
Polyform Inc 3125 22nd St SE Salem 97302 503 585-0163
Polzel Terry 4992 Verda Ln NE Keizer 97303 503 463-6402
Pombrol Telma 3744 Bell Rd NE Salem 97301 503 581-6102
Pomerenke Robert 4362 Cloudview Dr S Salem 97302 503 585-9919
Pomeroy Chuck & Bev 3253 Roosevelt NE Salem 97301 503 316-9199
E F 235 S Edwards Rd Mnmth 97361 503 838-1093
Pomeroy Eyecare PC
1960 Commercial St SE Salem 97302 503 363-9011
Pomeroy J 503 585-3493
Pat & Lila 2880 S Kings Valley Hwy Dllas 97338 503 831-3141
Ronald R 4748 Rebecca NE Salem 97305 503 390-7034
Pomme Edouard Stytn 97383 503 769-3150
Joseph & Kimberly 1510 Highland Dr Stytn 97383 503 769-6959

Pommerening M 367 Garland Way N Keizer 97303 503 393-5498
Teresa 876 Moneda Ave N Keizer 97303 503 304-1033
Pommier Justin & Summer
1385 Baker NE Salem 97301 503 363-9447
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Pomroy Dennis & Gayle
2300 Brush College Rd NW Salem 97304 503 361-7882
Ponce Barrera-Maria Steven 503 362-7877
Guadalupe 4030 La Palms Ln Salem 97305 503 856-9947
Guillermo 4862 Regal Dr NE Salem 97301 503 362-4308
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Margarito 4555 Dean NE Salem 97301 503 365-9577
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Pond Crafters 4570 River Rd N Keizer 97303 503 390-4380
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Ponder Paul L 1230 3rd St Lyns 97358 503 859-2242
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Mike & Betty 649 Airport Way Indpndnce 97351 503 606-9767
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Scott 503 315-8966
Ponsford Jay & Joanne
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David G 503 363-0361
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Hayward 503 588-7311
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Warren 3100 Turner Rd SE Salem 97302 503 364-6436
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Poot L A 503 463-6520
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Richard 9205 River Rd NE Salem 97303 503 390-5907
Pop-A-Lock 503 391-5555
Pope Amanda 804 N Monmouth Ave Mnmth 97361 503 838-0929
Brian & Anne 630 Tryon Ave NE Salem 97301 503 585-6323
Burton & Bonny 450 SE La Creole Dr Dllas 97338 503 623-4616
Chester 309 NW Robert Dllas 97338 503 623-0282
Craig A & Dina L 15040 Airlie Rd Mnmth 97361 503 838-6444
Ferron & Vicki 503 623-6880
Howard E 12680 S Pacific Hwy W Mnmth 97361 503 838-2605
Howard & Genie 685 Marino Dr N Keizer 97303 503 393-9103
James D 1843 Cottontail Ct NE Salem 97305 503 391-6673
Joe & Lu 1904 Northview Dr NE Keizer 97303 503 393-4484
John & Donna 340 NE Crest St Sblmty 97385 503 769-2368
John & Shannon 503 362-3701
Louis Lyns 97358 503 859-3260
Patrick & Heidi 503 378-7673
Randy & Terri 503 623-63[illegible]
Vernon O 9457 Snoddy Dr SE Amsvlle 97325 503 769-54[illegible]2
Popham Harold 3831 Camisltaun Ct NE Salem 97305 503 581-29[illegible]3
Tom 503 364-92[illegible]7
Popinga J 1115 Satara Ct NW Salem 97304 503 371-60[illegible]
Poplar Fred 503 606-09[illegible]
Poplin H 1803 Park Ave NE Salem 97301 503 363-647[illegible]
Popovich Brett 8557 Saghalie Dr S Salem 97306 503 378-138[illegible]
Popp Al's 198 NE Santiam Blvd Mllcty 97360 503 897-222[illegible]
Poppenheimer Jerry L 503 363-0002
Poppitz Arnold 12505 Sauerkraut Rd Mnmth 97361 503 838-5107
Edwin & Laurie 12465 Sauerkraut Rd Mnmth 97361 503 606-9289
Edwin T Pawnee Salem 503 362-7021
Porath M 4700 Gardner Rd SE Salem 97302 503 581-0448
Porras Adam 999 Shores NE Salem 97301 503 371-1182
C 503 364-2037
Clemente 4743 Cougar Ct SE Salem 97317 503 581-6030

Porras J Cruz 3057 Sorensen Ct NE Salem 97301 503 375-3351
Port A Lee Rev 300 SE La Creole Dr Dllas 97338 503 623-3324
Port Douglas 2845 Winter SE Salem 97302 503 581-3207
Portal Chris 405 Alan Fllscty 97344 503 787-4319
Portales Marie 4679 Hayesville Ct NE Ct NE Salem 503 390-5941
Portamedic 838 Commercial St NE Salem 97301 503 362-9525
Porter Albert 1091 Chemawa Rd N Keizer 97303 503 390-2611
Porters Cabinet Shop
Albert 4885 River Rd N Keizer 97303 503 393-5310
Angela & Craig 4851 Saunter Lp Ne Salem 97305 503 589-4653
Porter & Associates Apraisal Services 503 371-6394
Porter Barbara 3626 River Rd S Salem 97302 503 364-5486
Bert & Cindy 5514 Verda Ln NE Keizer 97303 503 588-5557
C 503 838-2550
C & J 1353 Madrona Ave SE Salem 97302 503 540-0335
C P 503 390-8081
Carol A 365 18th SE Salem 97301 503 364-0527
Darlene Amsvl 97325 503 749-4419
D F 503 371-0078
Don & Nita 503 585-8844
Donald 4100 Sample Rd FllsCty 97344 503 787-1401
Donald R 6499 Crampton Dr N Keizer 97303 503 393-5440
Doug & Anna 6603 Rippling Brook Dr SE Salem 97317 503 363-2313
Douglas & Suzanne 503 585-6150
E M 612 Cater Dr NE Keizer 97303 503 463-6634
Gail 1905 Michigan City Ln NW Salem 97304 503 763-7074
George D 5555 Hazelgreen Rd NE Salem 97305 503 393-6689
Henry Stytn 97383 503 769-5792
I V 503 362-7121
J 1025 38th Ave NE Salem 97301 503 363-0682
James 961 Wild Rose Ct Indpndnce 97351 503 606-0644
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Jerry 4495 Macleay Rd SE Salem 97317 503 371-7752
John S 4175 Verda Ln NE Keizer 97303 503 393-6886
Joyce 1397 Stonefield Pl N Keizer 97303 503 393-3755
K 503 606-0471
Kathleen 4066 Commercial St SE Salem 97302 503 375-2509
Kenneth 3100 Turner Rd SE Salem 97302 503 391-0232
Kevin 900 7th St Lyns 97358 503 859-4558
L 503 370-7992
Larry 503 370-7992
L & Don 885 E Virginia St Stytn 97383 503 769-2391
Leo 299 Dorcas Dr N Keizer 97303 503 463-6475
L K 1139 Margaret St E Mnmth 97361 503 606-0761
L M 2060 Laurel Ave NE Salem 97301 503 363-3764
Lois A 503 362-7453
N Jean 400 Madrona Ave SE Salem 97302 503 587-8808
Odas V 13495 Duckflat Rd SE Trner 97392 503 769-7404
Phil & Dorothy Mrs 3624 Lawrence SE Salem 97302 503 363-1031
Preston 3249 Delaney Rd SE Trner 97392 503 364-0934
Randy & B 1104 Swingwood Ct NE Keizer 97303 503 393-4185
Raymond Lee 6536 Hays Ln SE Amsvlle 97325 503 749-2843
Porter Rd Farm 10963 Porter Rd SE Amsvlle 97325 503 769-4395
Porter Richard 684 N 4th Ave Stytn 97383 503 769-2514
Richard K 386 Benji Ct NE Salem 97301 503 581-3110
Robbin 503 585-9496
Robert 9495 Helmick Rd Mnmth 97361 503 838-2875
Robert E & Hazel 176 NE Crest St Sblmty 97385 503 769-4786
Robert F & Sondra L
46250 Lyons-Mill City Dr Lyns 97358 503 859-2773
Roger & Terri PO Box 122 Sblmty 97385 503 769-6803
Sharon B 1759 Commercial St SE Salem 97302 503 566-6783
Stan & Linda Sblmty 97385 503 769-4729
Suzanne & Scott 503 391-1691
Thomas 8634 Darley Rd SE Amsvlle 97325 503 749-2259
Tiffany 4634 Sunnyside Rd SE Salem 97302 503 378-9797
Traci J 289 Mize Rd SE Salem 97302 503 362-5967
Vonda Lyns 97358 503 859-2723
W 503 362-7379
W 503 589-9970
Porter William A dmd 1355 Edgewater NW Salem 97304 503 588-6960
Porter William & Sherri 503 581-2722
Yolanda Amsvlle 97325 503 448-1032
Porterfield Kevin & Angie
920 Jefferson NE Salem 97301 503 391-7570
Stanley W 6890 Sunset Way SE Trner 97392 503 743-2559
Porterrie Dale 2525 James Howe Rd Dllas 97338 503 831-5865
Dale 2525 James Howe Rd Dllas 97338 503 831-1507
Porter's Cabinet Shop
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Porter's Pub 4820 River Rd N Keizer 97303 503 393-3269
Porth D & M 503 585-5939
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Luis 3432 Silvercedar Pl NE Salem 97305 503 588-7540
Wenceslao 4163 Market NE Salem 97301 503 589-4179
Portinga Paula 503 391-2495
Portland Christine L Psyd lcsnsd physcologist
1505 Water St NE Salem 97301 503 363-2430
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(Continued on next page)

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 814

Exhibits in Support of Surrebuttal Testimony

September 15, 2008

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
NARRATIVE SUMMARY
TWELEVE MONTHS ENDED DECEMBER 31, 2009
(000)

Item	Staff	Issue	Revenue Requirement Effect
		Revenue Requirement on the Company's Filed Results	**$147,233**
		Proposed Staff Adjustments	
S-0	BC	**Rate of Return** Stipulated Agreement	**(12,906)**
S-1	PR	**Other Electric Revenues** Adjust Other Revenues per Stipulated Agreement to offset Schedule 300 Revenues included in test period	**$471**
S-2	CO	**Research and Development** Staff proposes to normalize the amount spent on Research and Development	**($1,752)**
S-3	CO	**Workforce Adjustment** Staff proposes to normalize workforce in accordance with historic growth plus 26 FTE	**($8,891)**
S-4	CO	**Corp Incentives** Staff proposes to remove incentives related to the financial performance of the utility including Officer Incentives	**(6,963)**
S-5	CO	**Cap Ex** Staff proposes to remove capital expenditures not known and measurable	**(13,286)**
S-6	CO	**Lease Adjustment** Stipulated Agreement	**0**
S-7	PR	**Fuel Adjustment** Stipulated Agreement	**0**
S-8	PR	**Membership Adjustment** Stipulated Agreement	**0**
S-9	DB	**A&G and O&M** Staff proposes to make adjustments to A&G and O&M based various areas. Detail can be found on workpapers provided by Staff for settlement in a separate packet.	**(8,336)**
S-10	ED	**WECC Reliability Center, Regional Trans Planning & flow mitigation**	**(156)**

Staff/814
Owings/1

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
NARRATIVE SUMMARY
TWELEVE MONTHS ENDED DECEMBER 31, 2009
(000)

		Staff proposes to make adjustments T&D based on PGE's proposal to increase costs related to Regional Trans planning, WECC reliability center and unscheduled flow mitigation	
S-11	ED	**Fixed Plant Costs** Staff proposes to adjust cost increases related to Beaver, Colstrip and Boardman	**(6,348)**
S-12	ED	**Kelso Beaver Pipeline Transmission** Remove costs per Stipulated Agreement	**(1,040)**
S-13	ED	**NERC/WECC Consultant, RCM Program costs, Misc Unspecified software upgrades** Staff proposes to remove costs associated with NERC/WECC Consult., RCM Program costs and Miscellaneous software upgrades	**(520)**
S-14	DB	**Property Tax Adjustment** Staff proposes to adjust property taxes associated with Port Westward and Biglow Canyon	**(3,001)**
S-15	ED	**NVPC Adjustment** Per Stipulated Agreement	**(5,058)**
S-16	CO, DB, PR	**Revenue Sensitive Costs** Staff proposes to Adjust Franchise Fees, Uncollectibles Expense and Taxes other than Income Taxes as a percentage of overall Revenue Sensitive Costs	**(1,805)**
S-17	LG	**Schedule 300** No changes will be adopted to Schedule 300 per Stipulated Agreement	**0**
S-18	CO	**Port Westward and Biglow Canyon** A true-up of Cap Costs per Stipulated Agreement	**(113)**
S-19	CO	**Energy Audits** Staff proposes to remove costs associated with Energy Audits from O&M.	**(287)**
PGE - 1		**NVPC UPDATE** April 4, 2008 Update of PGE's forecasted fuel costs and power purchases	**0**
S*	CO	Adjustment to rounding error	(121)
		Total Staff-Proposed Adjustments (Base Rates):	(70,112)
		Staff-Calculated Revenue Requirements Change (Base Rates):	**$77,121**

Staff/814
Owings/2

PORTLAND GENERAL ELECTRIC
UE 197/198
SUMMARY OF REVENUE REQUIREMENT
TWELEVE MONTHS ENDED DECEMBER 31, 2009
(000)

	SUMMARY SHEET	2009 Results Per Company Filing (1)	Staff Proposed Adjustments and NVPC Update (2)	2009 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	**Operating Revenues**					
2	Retail Sales	$1,586,821	$0	$1,586,821	$77,121	$1,663,942
3	Wholesale Sales	0	0	0	0	0
4	Other Revenues	19,346	(455)	18,891	0	18,891
5	**Total Operating Revenues**	$1,606,167	($455)	$1,605,712	$77,121	$1,682,833
6	**Operating Expenses**					
7	Net Variable Power Costs	$806,699	($4,860)	$801,839	$0	$801,839
8	Production	108,251	(7,600)	100,651	0	100,651
9	Other Power Supply (Trojan)	129	0	129	0	129
10	Transmission	11,937	(150)	11,787	0	11,787
11	Distribution	68,198	(16,950)	51,248	0	51,248
12	Customer Accounting	65,235	(276)	64,959	0	64,959
13	OPUC Fees	4,959	0	4,959	241	5,200
14	Uncollectibles	7,617	(1,734)	5,883	370	6,253
15	Administrative and General	115,165	(7,132)	108,033	0	108,033
16	**Total Operation & Maintenance**	$1,188,190	($38,702)	$1,149,488	$611	$1,150,099
17	Depreciation	$175,781	($3,073)	$172,708	$0	$172,708
18	Amortization	18,781	0	18,781	0	18,781
19	Taxes Other than Income	51,232	(2,884)	48,348	0	48,348
20	Income Taxes	16,718	18,133	34,851	28,561	63,412
21	Local taxes and Franchise Fees	39,893	0	39,893	1,939	41,832
22	**Total Operating Expenses**	$1,490,595	($26,526)	$1,464,069	$31,111	$1,495,179
23	**Net Operating Revenues**	$115,572	$26,071	$141,643	$45,866	$187,509
24	**Average Rate Base**					
25	Electric Plant in Service	$5,173,537	($93,141)	$5,080,396	$0	$5,080,396
26	Less: Accumulated Depreciation & Amortization	(2,674,938)	10	(2,674,928)	0	(2,674,928)
27	Accumulated Deferred Income Taxes	(286,869)	(20)	(286,889)	0	(286,889)
28	Accumulated Deferred Inv. Tax Credit	(271)	0	(271)	0	(271)
29	**Net Utility Plant**	$2,211,458	($93,151)	$2,118,307	$0	$2,118,307
30	Plant Held for Future Use	$0	$0	$0	$0	$0
31	Acquisition Adjustments	0	0	0	0	0
32	Working Capital	77,511	(1,380)	76,131	1,618	77,749
33	Fuel Stock	67,707	0	67,707	0	67,707
34	Materials & Supplies	0	0	0	0	0
35	Customer Advances for Construction	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0
37	Prepayments	(37,755)	0	(37,755)	0	(37,755)
38	Misc. Deferred Debits	23,917	0	23,917	0	23,917
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0
40	**Total Average Rate Base**	$2,342,838	($94,531)	$2,248,307	$1,618	$2,249,925
41	**Rate of Return**	4.93%		6.30%		**8.33%**
42	**Implied Return on Equity**	3.30%		6.03%		**10.10%**

Staff/814
Owings/3

PORTLAND GENERAL ELECTRIC
UE 197/198
REVENUE SENSITIVE COSTS
TWELEVE MONTHS ENDED DECEMBER 31, 2009
(000)

REVENUE SENSITIVE COSTS	COMPANY REQUEST	STAFF ADJUSTED
Revenues	1.00000	1.00000
Operating Revenue Deductions		
Uncollectible Accounts	0.00480	0.00380
Taxes Other - Franchise	0.02514	0.02514
OPUC Fees (separate line item on Model)	0.00313	0.00313
- Resource supplier		
State Taxable Income	0.96694	0.96794
State Income Tax @ 5.375%	0.05197	
State Income Tax @ 5.120%		0.04956
Federal Taxable Income	0.91496	0.91838
Federal Income Tax @ 35%	0.32024	0.32143
Total Taxes	0.37221	0.37099
Total Revenue Sensitive Costs	0.40527	0.40306
Utility Operating Income	0.59473	0.59694
Net-to-Gross Factor	**1.68145**	**1.67520**

State Tax Rate @ 5.120

Input:		
	5.12000%	STATERATE (Income Tax Rate)
	5.20000%	WORKINGCAP

Staff/814
Owings/4

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
SUMMARY OF ADJUSTMENTS
TWELEVE MONTHS ENDED DECEMBER 31, 2009
(000)

	Staff Adjustments	Other Revenues (S-1)	Research & Develop Adjust (S-2)	Workforce Adjustment (S-3)	Corp Incentives (S-4)	Cap Ex (S-5)	A&G and O&M (S-9)	WECC Rel, Reg Trans Plan Flow Mitigation (S-10)	Fixed Plant Costs (S-11)	Kelso-Beaver Pipeline Transmission (S-12)	WECC, RCM, Misc Soft & GP (S-13)	Property Taxes (Taxes Other) (S-14)
1	**Operating Revenues**											
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Wholesale Sales	0	0	0	0	0	0	0	0	0	0	0
4	Other Revenues	(455)	0	0	0	0	0	0	0	0	0	0
5	**Total Operating Revenues**	**($455)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
6	**Operating Expenses**											
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$0	0	$0	$0	$0
8	Production	0	0	0	0	0	0	0	(6,100)	(1,000)	(500)	0
9	Other Power Supply (Trojan)	0	0	0	0	0	0	0	0	0	0	0
10	Transmission	0	0	0	0	0	0	(150)	0	0	0	0
11	Distribution	0	0	(8,071)	(6,320)	0	(2,559)	0	0	0	0	0
12	Customer Accounting	0	0	0	0	0	0	0	0	0	0	0
13	OPUC Fees	0	0	0	0	0	0	0	0	0	0	0
14	Uncollectibles	0	0	0	0	0	0	0	0	0	0	0
15	Administrative and General	0	(1,683)	0	0	0	(5,449)	0	0	0	0	0
16	**Total Operation & Maintenance**	**$0**	**($1,683)**	**($8,071)**	**($6,320)**	**$0**	**($8,008)**	**($150)**	**($6,100)**	**($1,000)**	**($500)**	**$0**
17	Depreciation	0	0	(108)	(85)	(2,856)	0	0	0	0	0	0
18	Amortization	0	0	0	0	0	0	0	0	0	0	0
19	Taxes Other than Income	0	0	0	0	0	0	0	0	0	0	(2,884)
20	Income Taxes	(174)	646	3,178	2,488	2,187	3,072	58	2,341	384	192	1,107
21	Local Taxes and Franchise Fees	0	0	0	0	0	0	0	0	0	0	0
22	**Total Operating Expenses**	($174)	($1,037)	($5,001)	($3,917)	($669)	($4,936)	($92)	($3,759)	($616)	($308)	($1,777)
23	**Net Operating Revenues**	**($281)**	**$1,037**	**$5,001**	**$3,917**	**$669**	**$4,936**	**$92**	**$3,759**	**$616**	**$308**	**$1,777**
24	**Average Rate Base**											
25	Electric Plant in Service	0	0	(3,178)	(2,488)	(86,750)	0	0	0	0	0	0
26	Accumulated Depreciation & Amortization	0	0	0	0	0	0	0	0	0	0	0
27	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
28	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	0	0
29	**Net Utility Plant**	$0	$0	($3,178)	($2,488)	($86,750)	$0	$0	$0	$0	$0	$0
30	Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0	0
31	Acquisition Adjustments	0	0	0	0	0	0	0	0	0	0	0
32	Working Capital	(9)	(54)	(260)	(204)	(35)	(257)	(5)	(195)	(32)	(16)	(92)
33	Fuel Stock	0	0	0	0	0	0	0	0	0	0	0
34	Materials & Supplies	0	0	0	0	0	0	0	0	0	0	0
35	Customer Advances for Construction	0	0	0	0	0	0	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0	0	0	0	0	0	0
37	Prepayments	0	0	0	0	0	0	0	0	0	0	0
38	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	0	0
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0	0	0	0	0	0	0
40	**Total Average Rate Base**	**($9)**	**($54)**	**($3,438)**	**($2,692)**	**($86,785)**	**($257)**	**($5)**	**($195)**	**($32)**	**($16)**	**($92)**
41	**Revenue Requirement Effect**	**$471**	**($1,752)**	**($8,891)**	**($6,963)**	**($13,286)**	**($8,336)**	**($156)**	**($6,348)**	**($1,040)**	**($520)**	**($3,001)**

Staff/814
Owings/5

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
SUMMARY OF ADJUSTMENTS
TWELEVE MONTHS ENDED DECEMBER 31, 2009
(000)

	Staff Adjustments	NVPC Adjustment (S-15)	Revenue Sensitive Costs (S-16)	Schedule 300 (S-17)	True up of Port Westward Biglow Canyon (S-18)	Energy Audit Costs (S-19)	UPDATE NVPC (S-20)	Total Adjustments (Base Rates)
1	**Operating Revenues**							
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0
3	Wholesale Sales	0	0	0	0	0	0	$0
4	Other Revenues	0	0	0	0	0	0	($455)
5	**Total Operating Revenues**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**($455)**
6	**Operating Expenses**							
7	Net Variable Power Costs	($4,860)	$0	$0	$0	$0	$0	($4,860)
8	Production	0	0	0	0	0	0	($7,600)
9	Other Power Supply (Trojan)	0	0	0	0	0	0	$0
10	Transmission	0	0	0	0	0	0	($150)
11	Distribution	0	0	0	0	0	0	($16,950)
12	Customer Accounting	0	0	0	0	(276)	0	($276)
13	OPUC Fees	0	0	0	0	0	0	$0
14	Uncollectibles	0	(1,734)	0	0	0	0	($1,734)
15	Administrative and General	0	0	0	0	0	0	($7,132)
16	**Total Operation & Maintenance**	**($4,860)**	**($1,734)**	**$0**	**$0**	**($276)**	**$0**	**($38,702)**
17	Depreciation	0	0	0	(24)	0	0	($3,073)
18	Amortization	0	0	0	0	0	0	$0
19	Taxes Other than Income	0	0	0	0	0	0	($2,884)
20	Income Taxes	1,865	665	0	18	106	0	$18,133
21	Local Taxes and Franchise Fees	0	0	0	0			$0
22	**Total Operating Expenses**	($2,995)	($1,069)	$0	($6)	($170)	$0	($26,526)
23	**Net Operating Revenues**	**$2,995**	**$1,069**	**$0**	**$6**	**$170**	**$0**	**$26,071**
24	**Average Rate Base**							
25	Electric Plant in Service	0	0	0	(725)	0	0	($93,141)
26	Accumulated Depreciation & Amortization	0	0	0	10	0	0	$10
27	Accumulated Deferred Income Taxes	0	0	0	(20)	0	0	($20)
28	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	$0
29	**Net Utility Plant**	$0	$0	$0	($735)	$0	$0	($93,151)
30	Plant Held for Future Use	0	0	0	0	0	0	$0
31	Acquisition Adjustments	0	0	0	0	0	0	$0
32	Working Capital	(156)	(56)	0	0	(9)	0	($1,380)
33	Fuel Stock	0	0	0	0	0	0	$0
34	Materials & Supplies	0	0	0	0	0	0	$0
35	Customer Advances for Construction	0	0	0	0	0	0	$0
36	Weatherization Loans	0	0	0	0	0	0	$0
37	Prepayments	0	0	0	0	0	0	$0
38	Misc. Deferred Debits	0	0	0	0	0	0	$0
39	Misc. Rate Base Additions/(Deductions)		0	0	0	0	0	$0
40	**Total Average Rate Base**	**($156)**	**($56)**	**$0**	**($735)**	**($9)**	**$0**	**($94,531)**
41	**Revenue Requirement Effect**	**($5,058)**	**($1,805)**	**$0**	**($113)**	**($287)**	**$0**	**($57,085)**

Staff/814
Owings/6

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 815

Exhibits in Support of Surrebuttal Testimony

September 15, 2008

STAFF EXHIBIT 815

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 08-133. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 197 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 816

Exhibits in Support of Surrebuttal Testimony

September 15, 2008

STAFF EXHIBIT 816

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 08-133. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 197 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 197
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 817

Exhibits in Support
of Surrebuttal Testimony

September 15, 2008

STAFF EXHIBIT 817

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 08-133. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 197 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 197
WITNESS: Dustin Ball

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Surrebuttal Testimony

September 15, 2008

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 900, PAGE 21, IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 08-133. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 197 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dustin Ball. I am employed by the Public Utility Commission of Oregon as a Senior Financial Analyst, Corporate Analysis and Water Regulation, in the Economic Research and Financial Analysis section of the Utility Program. My business address is 550 Capitol Street NE, Salem, Oregon 97308-2148. My Witness Qualification Statement can be found in my direct testimony, Exhibit Staff/301, Ball-Dougherty/1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is respond to Portland General Electric's (PGE) rebuttal testimony and to offer continued support of my recommended adjustments to PGE's Administrative and General (A&G) accounts, Operations and Maintenance (O&M) accounts, and Property Tax expense.

Q. DID YOU PREPARE EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/901 (supporting calculations), and Exhibit Staff/902 (PGE data request responses and other supporting documentation cited in this testimony).

Q. WHAT ARE THE REMAINING UNRESOLVED ISSUES THAT YOU WILL BE ADDRESSING IN YOUR TESMIONY?

A. I will address the following unresolved issues:

ISSUE 1: MEDICAL & DENTAL BENEFIT EXPENSE ADJUSTMENTS

Q. PLEASE SUMMARIZE PGE'S REBUTTAL TESTIMONY REGARDING UNION MEDICAL AND DENTAL BENEFITS.

A. According to PGE, Staff's adjustment to union benefits should be rejected in whole. In its rebuttal testimony, PGE does not address Staff's inflation factor (8.5 percent) or the application of increased benefits for only 10 months of the test period as proposed by Staff. PGE's rebuttal testimony simply addresses the 2007 base amount used in Staff's calculation of 2009 union medical and dental benefits.

Q. DOES STAFF'S BEGINNING BASE FOR CALCULATING UNION MEDICAL AND DENTAL BENEFITS INCLUDE BOTH UNION RETIREES AND ACTIVE UNION EMPLOYEES, AS DESCRIBED BY PGE?

A. Yes. Staff's base ($10,056,070) for calculating union medical and dental benefits includes both union retirees and active union employees and is based on PGE's total contribution for 2007. As described in PGE's response to OPUC Data Request No. 300, these contributions are broken down between active ($9,244,620) and retiree ($811,450) costs.

Q. WHAT WAS THE RESULT OF STAFF ESCALATING BOTH UNION RETIREE AND ACTIVE UNION EMPLOYEE BENEFITS AS OPPOSED TO ONLY ESCALATING THE ACTIVE UNION EMPLOYEE BENEFITS?

A. As Exhibit 901, Ball/2 illustrates, Staff's calculation resulted in a forecasted union medical and dental benefit amount that is $127,911 greater than what would have been forecasted under the methodology proposed by PGE in rebuttal testimony.

Q. STAFF ESCALATED BOTH UNION RETIREE AND ACTIVE UNION MEDICAL AND DENTAL BENEFITS TO ARRIVE AT ITS FORECASTED 2009 EXPENSE. DOES THIS METHOD SUPPORT PGE'S RECOMMENDATION TO REJECT STAFF'S PROPOSED ADJUSTMENT?

A. No. To the contrary, what PGE has identified, and as illustrated in Staff Exhibit 901, Ball/2, is that Staff's proposed adjustment is actually less than it would otherwise be. Specifically, Staff's direct testimony proposes an escalation factor of 8.5 percent for union benefits, which is the high end of projected rate increases based on recent studies concerning benefit costs. In rebuttal testimony, PGE correctly pointed out that Staff should have only increased active union medical and dental benefits by this amount and then added the union retiree benefits. As a result, Staff's proposed union medical and dental benefits represents an approximate 9.25 percent escalation factor for active union employees, which is substantially greater than the 8.5 percent supported in Staff's direct testimony, (Staff/300, Ball-Dougherty/3).

Q. ARE THERE ANY ADDITIONAL REASONS THAT THE COMMISSION SHOULD ADOPT STAFF'S PROPOSED ADJUSTMENT?

A. Yes. As described in Staff's direct testimony (Staff/300, Ball-Dougherty/3), PGE's 2009 forecasted union medical and dental benefits are based on an increased cost for the entire 2009 test year. This is not accurate. PGE's current union contract is effective through February 2009 and PGE will not realize any increase to active union medical and dental benefits during the first two months of 2009. As PGE will only incur 10 months of increased medical and dental benefits for active union employees, the Commission should accept Staff's proposal to reduce any associated increase of active union medical and dental benefits by 16.66 percent (2 months divided by 12 months).

Q. WILL YOU BE ADDRESSING NON-UNION MEDICAL AND DENTAL BENEFITS OR THE ALLOCATION OF BENEFITS TO NON-UTILITY EMPLOYEES?

A. No. Based on the additional information provided by PGE in its rebuttal testimony, which was not previously available, Staff has chosen to remove its proposed adjustment to non-union medical and dental benefits. In addition, Staff has also agreed to remove its allocation adjustment for non-utility employees because the base amounts for calculating the 2009 forecast represents only the utility portion of benefits.

Q. PLEASE SUMMARIZE YOUR UPDATED PROPOSED ADJUSTMENT TO MEDICAL AND DENTAL BENEFITS?

A. The following table highlights Staff's updated proposal.

Table 1 – Medical and Dental Benefits Adjustment

PGE's UE 197 Expense	**$31,554,803**
Staff Recommended Union Benefit	$11,541,226
Staff Recommended Non-union Benefit	$19,046,181
Staff Recommended Actuarial Study	$434,722
Sub-total	$31,022,129
Total Adjustment	**$532,674**

As the above table indicates, Staff's revised adjustment is $532,674.

ISSUE 2: OTHER BENEFIT EXPENSE ADJUSTMENTS

Q. PLEASE SUMMARIZE PGE'S REBUTTAL TESTIMONTY REGARDING STAFF'S ADJUSTMENTS TO OTHER BENEFITS.

A. PGE contends that Staff's proposed adjustment will disallow benefits that represent a fairly small portion of overall benefits and which represent a critical part of PGE's overall benefits package designed attract and retain qualified employees.

Q. GIVEN THE RELATIVELY SMALL INVESTMENT IN OTHER EMPLOYEE BENEFITS AS A PORTION OF OVERALL EMPLOYEE BENEFITS, IS STAFF'S PROPOSED ADJUSTMENT UNREASONABLE AS PGE ALLEGES?

A. No. Staff's proposed adjustments are reasonable; I will discuss each adjustment below.

- Occupational Health – While Staff agrees that PGE should recover prudently spent funds for occupational health benefits, Staff disagrees with PGE on the level of funding that will be required in 2009. While PGE states in rebuttal testimony that participation in these programs increased 46 percent between 2006 and 2008, it is program costs that are being set in the rate case, not program participation. A review of actual non-labor program costs indicates that expenses increased by approximately two percent from 2006 to 2007. Additionally, Staff compared actual program costs from January through July 2007 ($129,309) to costs for January through July 2008 (131,479)[1]. This comparison revealed an increase of approximately 1.7 percent. Although program participation may have significantly increased between 2006 and 2008, it is program costs that are being set in the rate case. The documentation received by Staff does not support PGE's proposed level of program funding. Staff's proposal to allow $224,434 in funding for occupational health benefits during 2009, which is an increase of approximately 19 percent over two years, is reasonable.

- Ergonomics and Integrated Absence Management (IAM) - PGE has characterized Staff's adjustment to this program as counter-productive and explains that the IAM program is designed to increase efficiency in managing absences and result in reducing the number of days employees are off work. Although this program may very well offer the benefits described by PGE, the Company has yet to identify any benefits (in the form of cost reductions) to customers associated with the program that have been taken into account in this rate case. See PGE's response to

[1] See PGE's response to OPUC Data Request No. 421 (Staff/902).

OPUC Data Request No. 102. Staff's proposed adjustment reflects that customers should not provide funding, through rates, for a program for which benefits (cost reductions) are not also reflected in rates.

- Occupational Fitness – Staff agrees that PGE should recover prudently spent funds for occupational fitness benefits. However, Staff disagrees with PGE on the level of funding that will be required in 2009. In its rebuttal testimony, PGE provides a detailed explanation regarding increased employment testing that has occurred during 2008 as compared to 2007. This very well may be the case, but again, the rate case is setting program costs, not the level of testing. While PGE's testimony indicates that the level of employment testing conducted has been constantly increasing from 2005 through 2007, the fact is that program costs have actually decreased from $47,739 in 2005 to $46,206 in 2007. Although the dollar amount of this decrease is minor, costs did decrease while the level of testing increased. Again, Staff compared program expenses from January through July 2007 ($26,556) to costs from January through July 2008 ($26,415)[2]. This comparison revealed a slight decrease in program costs when comparing the two time periods, and does not support PGE's proposed level of program funding. Staff's proposal to allow $47,976 in funding for occupational fitness during 2009, is reasonable.

[2] See PGE's response to OPUC Data Request No. 421 (Staff/902).

- Recreation Program – These activities are discretionary, take place outside the workplace, are not required to provide safe and adequate service to customers, and should not be funded by customers. Staff recommends that the Commission remove the cost of these of these activities.
- Health Club Partial Reimbursement - Staff agrees that PGE should recover prudently spent funds. However, Staff disagrees with PGE on the level of funding that will be required in 2009. Although PGE has expanded this program to include activities such as yoga, Pilates, tai chi, etc. that may increase participation by employees, it is unlikely that these new activities will cause participation increases that will almost double program costs, as presented by PGE in response to OPUC Data Request No. 299. In review of program expenses broken down by month, it appears that PGE incurs program expenses on a quarterly basis. Staff compared the first two quarters of 2007 ($12,958 and $14,976) to the first two quarters of 2008 ($13,551 and $15,528)[3]. This comparison indicates increased program costs of less than five percent, and does not support PGE's proposed level of program funding. Staff's proposal to allow a 20 percent cost increase resulting from increased participation, and to then increase the expense to 2009 using the CPI-U, is reasonable. Staff recommends adopting the 2009 test year program costs at $65,000.

[3] See PGE's response to OPUC Data Request No. 420 (Staff/902).

- Commuter Program – Staff has chosen to remove its proposed adjustment to the commuter program.
- Service Awards – Service awards are similar to merit based bonuses. Staff's adjustment is reasonable and is in line with the Commissions policy to disallow 50 percent of merit-based bonuses because they equally benefit shareholders and customers.
- Retiree Association and Retiree Luncheon – Staff recommends disallowance of this expense because it is discretionary and is not required to provide safe and adequate service to customers.
- Executive Financial Planning – In rebuttal testimony, PGE has agreed to remove this expense from its revenue requirement.
- Other – Staff recommends disallowance of these expenses as they were unidentified by PGE.

Q. PLEASE SUMMARIZE STAFF'S POSITION REGARDING OTHER BENEFITS.

A. The following table highlights Staff's adjustment to other benefits.

Table 2 – Certain Other Benefit Adjustments

Expense	PGE Baseline 2009 Benefit Costs	Staff Adjustments	Staff's 2009 Benefit Costs
Occupational Health	$253,360	($28,926)	$224,434
Ergonomics and IAM	$75,297	($41,046)	$34,251
Occupational Fitness	$58,620	($10,644)	$47,976
Recreation Program	$25,825	($25,825)	$0
Health Club Partial Reimbursement	$100,000	($35,000)	$65,000
Commuter Program	$25,101	($0)	$25,101
Service Awards	$225,000	($112,500)	$112,500
Retiree Activities	$13,200	($13,200)	$0
Executive Financial Planning	$31,500	($31,500)	$0
Other	$9,315	($9,315)	$0
Total	**$817,218**	**($307,956)**	**$509,262**

As the above table indicates, Staff's revised adjustment is $307,956.

ISSUE 3: INSURANCE EXPENSE ADJUSTMENTS

Q. PLEASE SUMMARIZE PGE'S REBUTTAL TESTIMONY REGARDING INSURANCE PREMIUMS.

A. In its rebuttal testimony, PGE proposed three changes to Staff's adjustment regarding insurance premiums. First, PGE characterized Staff's adjustment to Directors and Officers (D&O) Liability Insurance coverage as unreasonable. Second, PGE made adjustments to "update" its property insurance policies due to "policy renewals". Third, PGE disagrees with Staff's utility allocation and stated that such an adjustment would be redundant.

Q. PLEASE ELABORATE ON STAFF'S PROPOSED ADJUSTMENT TO THE EXCESS D&O LIABILITY INSURANCE.

A. While PGE asserts that the full cost of excess D&O insurance should be borne by customers, they fail to elaborate on the benefits of such policies. It is PGE shareholders who elect the Board of Directors, who in turn appoint the Company's top management, for whom these policies protect. D&O insurance offers protection for PGE's top management in the event they are sued in conjunction with the performance of their duties as they relate to the Company. Customers, who have no say in electing or appointing PGE's Directors or Officers, should not be held financially responsible in providing 100 percent of insurance coverage against business decisions or improprieties by management which results in lawsuits. This is especially true given the fact that roughly half of all such lawsuits are brought by the very shareholders who elected the Board of Directors. While these policies do provide protection for PGE's Directors and Officers, they also serve to protect shareholders. Staff's proposed adjustment to remove 50 percent of PGE's Excess D&O Liability Insurance is reasonable. Again, it is important to note that Staff did not recommend any adjustments to the primary level of D&O insurance costs.

Q. DOES STAFF HAVE ANY COMMENTS REGARDING THE UPDATES THAT PGE HAS MADE TO ITS PROPERTY INSURANCE PREMIUMS IN ITS REBUTTAL TESTIMONY?

A. Yes. PGE has not simply updated its property insurance policies to reflect policy renewals as its rebuttal testimony appears to indicate. Although not specifically identified, PGE is attempting to bring in a new insurance policy that was not included in its original UE 197 filing. As shown in Staff/302, page 4 of Staff's direct testimony, PGE's original UE 197 filing consist of four All-Risk policies ($2,778,647) and one Transmission and Distribution (T&D) policy

($1,584,622) totaling $4,363,269. Based on PGE's response to OPUC Data Request No. 413, All-Risk policies were updated in July 2008 with policy premiums totaling $2,352,900, a reduction of $425,747 from the UE 197 estimate. Additionally, the actual T&D policy indicates that the 2009 premium will be $1,500,000, a reduction of $84,622 from the UE 197 estimate. In rebuttal testimony, PGE not only updated these policies, but is also attempting to include a previously unidentified insurance policy in the amount of $383,089. The reduction to All-Risk and T&D policies of $510,369 along with an increase for the previously unidentified policy of $383,089 makes up the $127,280 decrease from PGE's original UE 197 filing to its updated forecast, as shown in Table 1 on UE197/PGE/1900, Piro – Tooman/17.

Q. IF THIS NEW POLICY WILL BE AN ACTUAL INSURANCE COST INCURRED IN THE 2009 TEST YEAR, SHOULDN'T IT BE INCLUDED IN THE RATE CASE?

A. Perhaps. While we all strive to have the best record developed by which to base PGE's revenue requirement, Staff recommends the Commission be cautious in allowing PGE to selectively increase costs as new items are identified several months after the case was filed when PGE may not voluntarily bring forth new cost savings or reductions in cost estimates. It would put Staff at a great disadvantage and prejudice customers for the Commission to allow this as a standard practice. Staff has reviewed the rate case based on the information provided in the original UE 197 filing as well as the Errata filing on April 3, 2008, and the Commission should consider holding

PGE to the information provided in the original UE 197, and April 3rd Errata filings.

Q. ALTHOUGH STAFF HAS MADE IT CLEAR THAT IT DOES NOT AGREE WITH PGE'S UPDATED PROPERTY INSURANCE OR LIABILITY INSURANCE PREMIUMS (SPECIFICALLY D&O INSURANCE), DOES STAFF AGREE WITH THE UPDATED WORKER'S COMP INSURANCE AND UPDATED INSURANCE PREMIUM CREDIT AMOUNTS PROVIDED BY PGE?

A. Yes. Staff agrees that the updated Worker's Comp insurance premium and insurance credit amounts are an accurate representation of the 2009 test year.

Q. PLEASE ADDRESS THE UTILITY ALLOCATION ISSUE.

A. Staff disagrees with PGE's statement that applying a utility allocation to insurance premium costs would be redundant. Staff based this adjustment on the actual insurance policies that were included in PGE's UE 197 filing and Staff is unaware of any corporate governance allowance that has been applied to these insurance premiums prior to the revenue requirement calculation. Without applying a utility allocation as proposed by Staff, customers would be funding 100 percent of insurance premiums through PGE's revenue requirement, even though these policies cover both utility and non-utility aspects of PGE's operations.

The Commission should note that Staff updated the utility allocation from 96.79 percent to 98.21 percent, which is the allocation percentage shown in PGE's 2007 Affiliated Interest Report.

Q. PLEASE SUMMARIZE STAFF'S ADJUSTMENT TO INSURANCE PREMIUMS?

A. As shown in Staff 901, Ball/3, Staff proposed adjustment to insurance premiums is a reduction from PGE's initial case in the amount of $1,833,961.

Q. PLEASE ADDRESS PGE'S REBUTTAL TESTIMONY REGARDING THE CALCULATION OF UNINSURRED LOSSES.

A. Staff agrees that its set of inflation figures were inadvertently off by one year in its escalation of past year's uninsured losses. Staff also agrees to the revised CPI-U escalators of 4.8% and 2.3% for 2008 and 2009 as proposed by PGE. While Staff has agreed to make the above changes in its calculation of uninsured losses, it does not agree with adjustment amount of $1,738,579 as proposed by PGE. As shown in Exhibit 901, Ball/4, Staff's revised adjustment amount is $1,749,039.

ISSUE 4: NON-LABOR ADMINISTRATIVE AND GENERAL EXPENSE ADJUSTMENTS

Q. PLEASE ADDRESS PGE'S REBUTTAL TESTIMONY REGARDING MISCELLANEOUS NON-LABOR ADMINISTRATIVE AND GENERAL EXPENSES (A&G).

A. Staff made numerous adjustments to PGE's miscellaneous A&G expenses and will address each of the adjustment categories below:

- Meals and Entertainment – These expenses are discretionary and are not required to provide safe and adequate service to costumers. Staff proposes a 50 percent sharing between customers and shareholders, which treatment mirrors the treatment of bonuses as well as the income tax treatment of these expenses.

- Office Refreshments, Catering, and Gifts - These costs are discretionary and are not related to the generation, transmission, and distribution of electricity. Staff proposes a 50 percent sharing of these expenses, similar to meals and entertainment, because customers should not assume the full burden of these costs.
- Civic and Political Activities – The Commission has not allowed regulated utilities to recover contributions for charities, community affairs and economic development through rates as Commission policy does not require customers to support causes in which they do not believe. In rebuttal testimony, PGE specifically addressed Staff's disallowance of internship for student workers. These costs are incurred as part of a Corporate Internship Program at De La Salle North Catholic High School to "sponsor" students who would otherwise not be able to afford the cost of a private education[4]. This is a civic activity which should not be funded by customers.
- Certain Legal and other Charges – Staff disallowed legal, environmental, rent expenses, and other charges which either did not reflect costs on an ongoing annual basis, or were not appropriate to include as test year miscellaneous A&G expenses.

Q. PLEASE SUMMARIZE THESE ADJUSTMENTS.

[4] See printout from De La Salle North Catholic High School's website, included in Staff/902

A. Staff proposes the following adjustment to miscellaneous A&G expenses:

Miscellaneous A&G	($596,036)

ISSUE 5: NON-LABOR TRANSMISSION AND DISTRIBUTION OPERATIONS AND MAINTENANCE EXPENSE ADJUSTMENTS

Porcelain Insulator Replacement Project

Q. IS STAFF'S PROPOSED ADJUSTMENT TO THE PORCELAIN INSULATOR REPLACEMENT PROJECT INAPPROPRIATE AS DESCRIBED BY PGE?

A. No. PGE has incorrectly characterized Staff's adjustment as reducing the level of funding for the program and thus significantly extending the length of time needed to complete the project. While Staff does propose funding for the Porcelain Insulator project based on an escalated 2007 contract labor and other non-labor expenses, Staff's adjustment should not have any effect on the length of time needed to complete this project.

Q. COULD YOU PLEASE DESCRIBE HOW STAFF'S PROPOSED ADJUSTMENT WOULD NOT REDUCE PROGRAM FUNDING AND SHOULD NOT AFFECT THE LENGTH OF TIME NEEDED TO COMPLETE THIS PROJECT?

A. Yes. During 2007 program expenses for the Porcelain Insulator Replacement project totaled $525,789, of which $144,158 was attributable to PGE labor expense and the remaining $381,631 was attributable to contract labor and non-labor expenses. PGE has not demonstrated that level of funding for the project during 2007 was unacceptable. The fact that Staff escalated only the

2007 contract labor and non-labor costs ($381,631) in arriving at the forecasted 2009 test year expense, should not be construed to mean that Staff is disallowing program expenses. Instead the Commission should view this approach as continuing the status quo (adjusted for inflation). Staff's position is that if PGE chooses to hire contractors as opposed to using PGE labor, as they did during 2007, then they should fund such a decision with the cost savings associated with a reduced PGE labor expense.

<u>Locating Expenses</u>

Q. IS STAFF'S METHOD FOR CALCULATING FORECASTED 2009 LOCATING COSTS BASED ON ASSUMPTIONS THAT ARE NOT VALID FOR THE 2009 TEST YEAR AS DESCRIBED BY PGE?

A. No. Staff based its forecasted 2009 locating costs on information provided by PGE in responses to OPUC Data Requests. PGE states in its rebuttal testimony that "*PGE submitted a test year increase in contract locating costs of approximately $480,000, not $688,548 (PGE/1600, Hawke/5*)." However, in direct testimony (PGE Exhibit 600, Hawke/13, line 3), PGE states that it is forecasting an increase in locating expenses of approximately $700,000. In response to OPUC Data Request No. 94, when asked what portion of the projected $700,000 locating cost increase was due to higher contract costs, PGE stated *"approximately 95% of the projected cost increase is due to the higher contract cost. The remaining portion of the cost increase, approximately 5% is due to the projected increase in locating requests."* Second, PGE's rebuttal testimony states that Staff's recommendation does not consider the increased number of locate requests in 2009. This is incorrect. Staff did not make an adjustment to PGE's forecasted increase (5 percent, as stated in response to OPUC Data Request No. 94) based on the relatively small dollar amount of this increase. Staff's adjustment is reasonable and based on information provided by PGE.

Arc-Flash Mitigation

Q. AS DESCRIBED IN ITS REBUTTAL TESTIMONY, PGE EXPECTS TO INCUR AN EXPENSE OF $361,000 IN 2009, TO COMPLY ARC-FLASH MITTIGATION THAT WILL BE COME AN OSHA REQUIREMENT IN 2009. SHOULD PGE BE ALLOWED FULL FUNDING OF $361,000 FOR ARC-FLASH MITIGATION?

A. No. The 2009 forecasted cost of $361,000 is to purchase personal protective clothing with a useful life of 3-5 years and is not an accurate representation of costs that will be incurred on an ongoing annual basis. Customers should not be required to provide funding at this elevated level through rates. As PGE describes in its response to OPUC Data Request No. 99, these protective clothing items are expected to have a useful life of 3-5 years. In essence, PGE expects to replace these items every 3-5 years, not annually. Staff's proposal does not prohibit PGE from purchasing the necessary protective clothing in a single year, but rather amortizes the cost to customers, and cost recovery to PGE, over the expected life of the items (Staff has proposed a four year life).

Q. DOES STAFF'S PROPOSED ADJUSTMENT TAKE INTO ACCOUNT THE ONGOING COSTS OF ARC-FLASH MITIGATION THAT PGE HAS DESCRIBED IN REBUTTAL TESTIMONY?

A. Yes. The ongoing costs described by PGE are expected to result from turnover and worn PPE once these items have outlived their useful life (3-5 years). Staff's proposal would provide PGE with a level of funding that would allow the company to recoup its initial investment in the first 4 years, then to replace approximately one quarter of these items in each subsequent year.

Q. WOULD A DEFERRAL AS PROPOSED BY PGE, WHICH WOULD RETURN ANY UNSPENT FUNDS TO CUSTOMERS, BE THE PROPER METHOD FOR PGE TO RECOVER ITS ARC-FLASH MITIGATION COSTS?

A. No. While PGE's proposed deferral would ensure that any unspent funds would be returned to customers, there is no guarantee that there will be any unspent funds. This proposal would not provide PGE with any incentive to control costs or to ensure that the protective clothing items are used to their fullest potential. PGE's proposal is to simply provide an elevated level of funding with the condition that if the money is not spent by the time PGE files it's next general rate case, it would then be returned to customers. On the other hand, Staff's proposal is to provide PGE with a definite level of funding on an ongoing basis, which gives an incentive to keep costs at a reasonably defined level.

Q. DOES STAFF HAVE ANY ADDITIONAL COMMENTS REGARDING ARC-FLASH MITIGATION?

A. Yes. On August 26, 2008, Staff proposed to the Commission[5], that the effective date for Arc-Flash Protection be delayed from January 1, 2009, until January 1, 2010. Based on this proposal, PGE would not be required to provide any Arc-Flash Mitigation during the 2009 test year. However, Staff realizes the importance of this program and does not propose reducing its original proposal to allow funding of this program.

EMS Development Costs

Q. PLEASE ADDRESS THE EMS DEVELOPMENT COST ADJUSTMENT?

A. Staff has agreed to remove this adjustment, as the expense represents PGE labor which is addressed separately in testimony by Staff Witness Owings.

Tree Trimming Expense

Q. IS STAFF'S RECOMMENDED ADJUSTMENT TO TREE TRIMMING EXPENSE UNREASONABLE AS PGE STATES IN TESTIMONY?

A. No. Staff's recommended adjustment is reasonable for several reasons. First, while PGE cites higher contract rates as the main driver for its increase in tree trimming expense, its actual tree trimming cost per line mile (CPLM) has decreased substantially from $2,532 in 2007, to a forecasted $2,100 in 2009. Additionally, based on OPUC Data Request No. 428, PGE is forecasting a substantial increase in the number of distribution line miles trimmed in 2008 and 2009, as compared to the past four years. During 2007, PGE trimmed

[5] See AR 528, included in Staff/902

3,777 miles of distribution lines; however, for 2008 and 2009, the forecasted number of miles has increased to 4,500. This substantial increase is at an annual cost of $1,518,300 (723 miles multiplied by $2,100 per mile). Staff has not received any indication from PGE or OPUC Safety Staff that the previous level of tree trimming was inadequate. In fact, in response to OPUC Data Request No. 384, when asked if the 2007 tree trimming cost included any additional workload not expected to reoccur in 2008 or 2009, PGE stated *"No. The 2007 tree trimming workload levels are expected to be ongoing."* This previously unidentified, and unjustified, additional workload, which is included in PGE's 2009 forecast, is greater than Staff's proposed adjustment.

Additionally, in response to OPUC Data Request Nos. 383 and 425, PGE states that it has forecasted inflation for tree trimming expenses of 8 percent. According to PGE the inflation factor of 8 percent is based on the rate it pays for a standard two-person trimming crew. However, confidential attachment B to OPUC Data Request No. 383 indicates that, [redacted], as opposed to the 8 percent increase that PGE claims.

Staff's proposed adjustment to reduce tree trimming expense by $1,346,103 continues to be reasonable.

<u>FITNES Program</u>

Q. BASED ON PGE'S EXPLANATION REGARDING THE REDUCTION TO UNDERGROUND FITNES PROGRAM EXPENSES FROM 2006 TO 2007, DOES STAFF STILL BELIEVE THAT AN ADJUSTMENT IS NECESSARY?

A. Yes. Staff believes that and adjustment to the underground FITNES program is still necessary. The most recent underground FITNES cycle, which encompassed the four year period beginning in 2004 and ending in 2007, had program expenses totaling $3,988,412. While this indicates that, on average, annual program costs were approximately $997,103, actual program costs during the first year ($448,484) and last year ($528,803) of the cycle were significantly less than the middle two years ($1,474,884 and $1,536,241).

While Staff's original proposal to base the test year on 2007 costs, which were significantly lower than the average, may not necessarily reflect costs on an ongoing basis, PGE's proposal to base ongoing costs on a high cost year (which was significantly higher than the average) also does not reflect costs on an ongoing basis.

Q. HOW DOES STAFF PROPOSE TO SET UNDERGROUND FITNES PROGRAM COSTS AT A LEVEL THAT WILL REFLECT COSTS ON AN ONGOING BASIS?

A. Staff has revised its original proposal to base the test year expense on an average per-year cost for the last four-year underground FITNES cycle, adjusted for inflation. As shown in Staff Exhibit 901, Ball/5, Staff calculated an average cost per year, adjusted for inflation to 2007, of $1,041,828. This amount was then adjusted for inflation to 2009, resulting in a test year expense of $1,116,948. This method for calculating underground FITNES program expenses provides an accurate representation of the costs on an ongoing basis.

Q. WHAT IS THE RESULT OF STAFF'S REVISED POSITION AS COMPARED TO ITS ORIGINAL PROPOSAL?

A. The result of Staff's revised position is an adjustment of $311,855, rather than the original proposed adjustment of $900,000.

<u>Miscellaneous O&M Expenses</u>

Q. PLEASE ADDRESS PGE'S REBUTTAL TESTIMONY REGARDING MISCELLANEOUS O&M EXPENSES.

A. Staff's has agreed to remove its adjustment regarding the contract forester, as Staff is proposing a separate adjustment regarding tree trimming expenses. Staff's adjustments to meals and entertainment, gifts, catering, and civic activities are explained in the miscellaneous A&G adjustments. As shown in Staff exhibit 901, Ball/6, removing the contract forester adjustment has reduced Staff's proposed adjustment to $111,961.

Q. PLEASE SUMMARIZE STAFF'S ADJUSTMENTS TO NON-LABOR TRANSMISSION AND DISTRIBUTION OPERATION AND MAINTENANCE EXPENSE.

A. In summary, Staff proposes the following adjustments:

Porcelain Insulator Replacement Project	($287,496)
Locating Expenses	($271,135)
Arc-Flash Mitigation Expenses	($270,750)
EMS Development Expenses	($0)
Tree Trimming Expenses	($1,346,103)
FITNESS	($311,855)

Miscellaneous O&M Adjustments	($111,961)
TOTAL O&M Adjustments	($2,599,300)

ISSUE 6: PROPERTY TAX ADJUSTMENTS

Q. PLEASE SUMMARIZE PGE'S REBUTTAL TESTIMONY REGARDING THE PROPERTY TAX ISSUE?

A. PGE's rebuttal testimony addresses two main areas of disagreement. First, PGE disagrees with the dollar amount of the adjustment that Staff made to 2007 base Oregon property taxes regarding Port Westward. According to PGE, the reduction to 2007 property taxes should be $1,212,985 as opposed to the $2,418,000 reduction proposed made by Staff. The second point of disagreement is that PGE disagrees in principle with Staffs method for calculating the 2009 test year's Oregon and Montana property tax expense. PGE further explains that property taxes are a function of assets, and that a more accurate method for calculating property taxes would be to tie the expense to rate base. According to PGE, by tying the property tax expense to rate base, to the extent that the Commission approves changes to PGE's 2009 test year rate base, the property tax expense would also be adjusted to reflect such a change.

Q. DOES STAFF AGREE THAT THE ADJUSTMENT MADE TO BASE 2007 PROPERTY TAXES, REGARDING PORT WESTWARD, SHOULD BE $1,212,985 AS OPPOSED TO THE $2,418,000 ORIGINALLY PROPOSED BY STAFF?

A. Yes. Staff agrees with PGE on this issue. PGE Exhibit/1408, Tooman – Tinker/1 is an accurate representation of Staff's proposed method of calculating Oregon and Montana property taxes, as adjusted to reflect this change.

Q. IS PGE'S PROPOSED METHOD OF TYING PROPERTY TAXES TO RATE BASE AN ACCURATE METHOD FOR CALULATING OREGON AND MONTANA TEST YEAR PROPERTY TAXES?

A. Not entirely. While Staff agrees that an acceptable way to measure the test year property tax expense would be as a function of the items that drive the tax, Staff does not agree with all components of PGE's calculation. Staff has identified two revisions to PGE's proposed method that are necessary in order for it to be reasonable. First, Staff does not believe that property taxes should be compared to the overall average rate base as proposed by PGE, but rather that the comparison should be to gross plant net-of-depreciation. Second, Staff believes that in addition to removing the property tax associated with Port Westward from the calculation, any plant/depreciation amounts associated with Port Westward should also be removed from the calculations.

Q. PLEASE EXPLAIN IN GREATER DETAIL STAFF'S FIRST PROPOSED REVISION TO PGE'S METHOD.

A. While PGE has proposed to tie property taxes to rate base, Staff believes that this comparison would be inaccurate and should instead be made between property taxes and gross plant net of depreciation. By applying this change to PGE's method, the property tax expense would be a direct factor of the actual items that drive the expense (gross plant – accumulated depreciation). While PGE proposes to compare property taxes to rate base, none of the additional items that are included in rate base (accumulated deferred tax, accumulated deferred income tax credits, miscellaneous deferred debits, operating materials & fuel, miscellaneous deferred credits, working cash, etc.) have an effect on PGE's property tax expense. Under the method proposed by PGE, not only would property taxes fluctuate based on changes to gross plant or depreciation but would also fluctuate based on a change to any of the other several factors which have nothing to do with property taxes.

Q. PLEASE EXPLAIN IN GREATER DETAIL, STAFF'S SECOND PROPOSED REVISION TO PGE'S METHOD?

A. While PGE's method appropriately removes the property tax associated with Port Westward from the 2007 property tax base, it fails to remove the associated plant/depreciation for Port Westward from the 2007 or 2009 amount to which it is comparing the property tax. Because PGE will not pay any property taxes on Port Westward during the 2009 test year, its effects should not only be removed from property taxes but should also be removed from gross plant and depreciation. To remove the Port Westward property tax amount without also removing the associated plant/depreciation is not reasonable.

Q. WHAT WOULD THE EFFECT OF THE ABOVE CHANGES TO PGE'S METHOD BE?

A. Although Staff does not have the actual numbers available to calculate with any certainty, Staff estimates that making the above mention changes would result in a property tax figure that is very similar to Staff's original proposal (with the exception of adjusting the 2007 base for Port Westward taxes). As shown in Staff Exhibit 901, Ball/7, Staff has made the following adjustments to PGE's proposed method for calculating the 2009 test year property tax for Oregon and Montana. First, in place of the 2007 actual average rate base as used by PGE, Staff inserted the actual average utility plant in service net of depreciation of $2,061,635,000. Next, Staff adjusted this amount to remove an estimated $140,045,000 (280,090,000 x 50%) of plant/depreciation associated with Port Westward. Now that both the numerator and denominator correctly exclude Port Westward (which will receive a property tax exemption during the 2009 test year), Staff calculated a ratio of 1.60067 percent which represents property tax expense as a share of utility plant net of depreciation.

Again, for purposes of estimating the 2009 test year property tax expense, Staff inserted the estimated utility plant net of depreciation of $2,497,795,000 in place of estimated average rate base as used by PGE. Staff then adjusted this net utility plant to remove the estimated $225,000,000 effect of Biglow 1, as well as an estimated $270,753,667 effect of Port Westward. The resulting 2009 net utility plant amount of $2,002,041,333 was then multiplied by the previously calculated ratio of 1.60067 percent, to arrive at non-Biglow estimated 2009 property tax expense of $32,046,014. Staff then added Biglow property taxes of $2,000,000 to arrive at a 2009 Oregon and Montana property tax amount of $34,046,014.

By making the above corrections to PGE's proposed method for calculating 2009 test year property taxes, the resulting property tax expense is $34,046,014, which is only slightly higher than the $33,937,897 property tax expense calculated using Staff's methodology (corrected for 2007 Port Westward taxes).

Q. DOES STAFF BELIEVE ITS ORIGINALLY PROPOSED ADJUSTMENT TO PROPERTY TAXES IS REASONABLE?

A. Yes. Staff believes that the amount of its original proposed adjustment is reasonable. This reasonableness is shown by minor difference as compared to the property tax expense calculated under a corrected PGE method. It should be noted, as PGE explained in its rebuttal testimony, that Staff's original proposal does not automatically adjust for any further adjustments to rate base that the Commission may adopt.

Q. GIVEN THAT STAFF'S ORIGINAL METHOD FOR DERIVING A THE 2009 TEST YEAR PROPERTY TAX EXPENSES FOR OREGON AND MONTANA DOES NOT AUTOMATICALLY ADJUST FOR ANY FURTHER ADJUSTMENTS TO GROSS PLANT OR ACCUMULATED DEPRECIATION, WHAT DOES STAFF RECOMMEND?

A. Staff recommends that the Commission adopt the PGE method, with the above mentioned revisions to use gross plant net of depreciation rather than total rate base, and to remove the Port Westward effect from both the property taxes and gross plant.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF STAFFS PROPOSED ADJUSTMENT?

A. As shown in Staff Exhibit 901, Ball/7, the revenue requirement impact is a reduction in the amount of $2,883,960. However, this figure would need to be adjusted to reflect the actual effects of Port Westward as well as any adjustments to the originally filed gross plant or accumulated depreciation amounts.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

CASE: UE 197
WITNESS: Dustin Ball

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Exhibits in Support
of Surrebuttal Testimony

September 15, 2008

PGE
UE 197
Test Year December 31, 2007
000's of Dollars

Adjustment is based on a series of adjustments in Account 901 through 935 and Accounts 560 through 598. The accompanying pages explain these adjustments in detail.

(Rounded to the nearest $1,000)

Description/ Account No.	Company Filing	Staff	Adjustment
A&G Accounts			
Medical & Dental Benefits	$ 31,555	$ 31,022	$ (533)
Other Employee Benefits	$ 20,950	$ 20,642	$ (308)
Insurance Premiums	$ 8,993	$ 7,159	$ (1,834)
Uninsured Losses	$ 4,078	$ 2,329	$ (1,749)
Directors Fees	$ 1,213	$ 888	$ (325)
Officer Vehicle Plan	$ 104	$ -	$ (104)
Various A&G Account Summary Adjustments			$ (596)
Total A&G Adjustments			**$ (5,449)**
Transmission & Distribution O&M Accounts			
Porcelain Insulator Project	$ 684	$ 396	$ (287)
Locating Costs	$ 689	$ 417	$ (271)
Arc-Flash	$ 361	$ 90	$ (271)
EMS Development Costs	$ 174	$ 174	$ -
Tree Trimming	$ 12,302	$ 10,956	$ (1,346)
FITNES Program Increase	$ 900	$ 588	$ (312)
Various O&M Account Summary Adjustments			$ (112)
Total O&M Adjustments			**$ (2,599)**
Total OMAG Adjustments			**$ (8,048)**
Property Tax Adjustment			
Oregon & Montana Property Tax	$ 36,930	$ 34,046	$ (2,884)
Total Adjustment to Taxes Other Than Income			**$ (2,884)**

UE 197 PGE - Medical & Dental Plan - A&G

Staff's Original Method for Calculating 2009 Union Medical and Dental Benefits

2007 Base (Active & Retiree)	$	10,056,070
2009 Forecast @ 8.5%	$	11,838,257
Increase over 2007	$	1,782,187
10 Months of Increase over 2007	$	1,485,156
2007 Actual	$	10,056,070
2009 Test Year (Active & Retiree)	**$**	**11,541,226**

Revised Method (Described by PGE) for Calculating 2009 Union Medical and Dental Benefits

2007 Active Union Base (PGE/1500, Barnett-Bell/15, Lines 16-17)	$	9,235,367
2009 Forecast @ 8.5%	$	10,872,105
Increase over 2007	$	1,636,738
10 Months of Increase over 2007	$	1,363,948
Actual 2007 Active Union Base (PGE/1500, Barnett-Bell/15, Lines 16-17)	$	9,235,367
2009 Active Union Benefits	$	10,599,315
2009 Union Retiree Benefits	$	814,000
2009 Test Year (Active & Retiree)	**$**	**11,413,315**

Staff's Original Calculation	$	11,541,226
Revised Calculation (Described by PGE)	$	11,413,315
Variance	**$**	**(127,911)**

Comments: 1. As shown above, Staff's original calculation of Union Medical & Dental Benefits actually resulted in a higher forecasted test year expense than what would have been forecasted under PGE's proposed method.

UE 197 PGE - Insurance Premiums- A&G

						Staff Policy Review	UE 197	DR's
Property	70% FM Global	800M	All Risks of Physical Loss or Damage	7-1-08 to 7-1-09	$ 1,690,342.00			
	20% AEGIS	800M	All Risks of Physical Loss or Damage	7-1-08 to 7-1-09	$ 441,700.00			
	10% Lloyd's Syndicate 1225	500M	All Risks of Physical Loss or Damage	7-1-08 to 7-1-09	$ 188,415.00			
	10% AEGIS	300M x 500M	All Risks of Physical Loss or Damage	7-1-08 to 7-1-09	$ 32,443.00	**$ 2,352,900**	$ 2,778,647	DR 66, 285
			Trans & Dist Property		$ 1,000,000.00	**$ 1,500,000**	$ 1,584,622	
Workers Comp	National Union Fire Insurance Co	55M	Excess Workers Comp	7-1-08 to 7-1-09	$ 279,985.00	**$ 279,985**	$ 282,613	DR 66, 285
Liability	AEGIS	35M	Excess Liability (First Layer)	3-15-08 to 3-15-09	$ 952,111.76			
	EIM	100M x 35M	Excess General Liability (Second Layer)	3-15-08 to 3-15-09	$ 665,000.00			
	AEGIS Lloyd's Syndicate 1225	25M x 135M	Excess Liability (Third Layer)	3-15-08 to 3-15-09	$ 104,657.00			
	Lloyd's of London	40M x 160M	Excess Liability (Fourth Layer)	3-15-08 to 3-15-09	$ 93,985.25	**$ 1,815,754**	$ 2,031,255	DR 66, 285
	AEGIS	25M	Fiduciary Liability Insurance	5-1-08 to 5-1-09	$ 85,000.00			
	US Specialty Insurance Co	10M x 25M	Excess Fiduciary Liability (Second Layer)	5-1-08 to 5-1-09	$ 25,000.00			
	EIM	15M x 35M	Excess Fiduciary Indemnity (Third Layer)	5-1-08 to 5-1-09	$ 31,610.00	**$ 141,610**	$ 173,769	DR 66, 285
	Central, American, Tokio, Mitsui	20M	Aviation	11-1-07 to 11-1-08	$ 39,829.00	**$ 39,829**	$ 53,813	DR 66, 285
	AEGIS	35M	D&O Liability Insurance	5-1-08 to 5-1-09	$ 539,695.00			
	EIM	50M x 35M	Excess D&O (Second Layer)	5-1-08 to 5-1-09	$ 508,775.00			
	US Specialty Insurance Co	25M x 85M	Excess D&O (Third Layer)	5-1-08 to 5-1-09	$ 220,875.00			
	XL Specialty	30M x 110M	Excess D&O (Fourth Layer)	5-1-08 to 5-1-09	$ 251,100.00	**$ 1,520,445**	$ 1,769,355	DR 66, 285
	Illinois National Insurance Co	1M	Business Automobile Coverage	3-31-08 to 3-31-09	$ 33,462.00	**$ 33,462**	$ 37,143	DR 66, 285
	Zurich American Insurance Co	10M each class	Commercial Crimes	3-1-07 to 3-1-09	$ 55,000.00	**$ 55,000**	$ 57,100	DR 66, 285
	ANI	100, 200, 300 M	Nuclear Energy Liability Program	1-1-08 to 1-1-09	$ 260,962.00	**$ 260,962**	$ 221,400	DR 66, 285
	Lloyd's of London		Builders Risk Coverage	4-1-07 to 4-1-08	$ 256,528.14			DR 66, 285
			Special Coverage			**$ -**	$ 3,333	DR 285
	Sub-Total					**$ 7,999,947**	**$ 8,993,050**	
	Adjustments		Remove 50% Excess D&O Insurance			$ (490,375)		
			Contingent "undeclared" Policyholder Credit (All-Risk)			$ (170,000)		DR 70
			Contingent "undeclared" Policyholder Credit (Nuclear)			$ (50,000)		
	Sub-Total					$ 7,289,572	$ 8,993,050	
			Utility Allocation			98.21%		
	Adjustment				**$ (1,833,961)**	**$ 7,159,089**	**$ 8,993,050**	

Comments:

1. Removed 50% of Excess D&O Liability and Fiduciary as a Shareholder Cost (Allowed 100% of primary coverage) since two main reasons for claims are financial statements issues and insider trading.
2. According to Foley & Lardner LLP, *"Shareholder-claims are the largest source of this risk, accounting for 50% of all D&O claims."* http://www.foley.com/files/tbl_s31Publications/FileUpload137/4087/DOLiability.pdf
3. According to Towers Perrin's, regarding D&O liability insurance claims, *"The claimant distribution continues to be heavily dependent on the ownership structure of survey participants. For example, 49% of the claims against public participants were brought by shareholders."* http://www.towersperrin.com/tp/jsp/tillinghast_webcache_html.jsp?webc=Tillinghast/United_States/Press_Releases/2007/20070413/2007_04_13.htm
4. Per a telephone conversation with PGE on 5/22/08, special coverage insurance for 2009 will be set at $0.
5. Contingent "undeclared" policyholder credit identified by PGE in response to DR 70. PGE is optimistic that this credit will occur.
6. Per a telephone conversation with PGE on 5/23/2008, PGE is expecting to receive a policy holder credit of $50,000 in 2009 for its Nuclear liability insurance.
6. Builders Risk Coverage for Phase II of Biglow should be capitalized into the project. See UE 197/PGE/500, Piro - Tooman/7.
7. Due to the soft state of the insurance market, Staff proposes to not allow any escalation and to hold the recent policy premiums steady for 2009.
8. The Utility Allocation applied above is derived from PGE's Cost Allocation Manual for the year 2007.

UE 197 PGE - Uninsured Losses - A&G

Actual Uninsured Losses	Automobile Liability	Auto/GL	General Liability	Workers Compensation W/C	CPI
2003		$760,802			1.027
2004		1,037,712		$1,775,970	1.034
2005		1,247,641		1,117,448	1.032
2006		603,123		1,126,975	1.029
2007		1,233,215		1,388,051	1.048
Escalated to 2008 Dollars					
2003 Loss in 2008 $$$		$899,123			
2004 Loss in 2008 $$$		1,194,136		$2,043,678	
2005 Loss in 2008 $$$		1,388,500		1,243,608	
2006 Loss in 2008 $$$		650,403		1,215,321	
2007 Loss in 2008 $$$		1,292,409		1,454,677	
Total		$5,424,571		$5,957,285	
5 year average		1,084,914		1,191,457	
2009 escalation (2.3%)		1,109,867		1,218,861	
UE 197 Amounts	330,200		1,942,600	1,804,967	
Adj		**$1,162,933**		**$586,106**	

Staff Proposed Adjustment **($1,749,039)**

UE 197 PGE - FITNES Program - O&M

		Escalated to 2007	DR
Program costs for 2004 escalated to 2007	$ 448,484	$ 491,498	381
Program costs for 2005 escalated to 2007	$ 1,474,884	$ 1,566,221	381
Program costs for 2006 escalated to 2007	$ 1,536,241	$ 1,580,792	381
Program costs for 2007 escalated to 2007	$ 528,803	$ 528,803	381
Total four-year cycle costs	$ 3,988,412	$ 4,167,314	
Average program cost per year	$ 997,103	$ 1,041,828	

Inflation Rates	
2005	3.2%
2006	3.2%
2007	2.9%
2008	4.8%
2009	2.3%

Average program costs per year in 2007 dollars	$ 1,041,828
Escalated to 2008 @ 4.8 percent	$ 1,091,836
Escalated to 2009 @ 2.3 percent	$ 1,116,948
2007 actual FITNES program costs	$ 528,803
PGE forecasted increase	$ 900,000
UE 197 FITNES program costs	$ 1,428,803
FITNES program costs per PGE	$ 1,428,803
Staff's FITNES program costs	$ 1,116,948
Staff's Revised Adjustment	**$ (311,855)**

UE 197 PGE - Miscellaneous O&M Adjustments - O&M

Summary of Various Adjustments by FERC Account

Staff Category	Staff Adjustment	Comments
FERC 56X		
Catering	(244)	
Civic Activity		
Total FERC 56X	**(244)**	
FERC 580		
Catering	(37,193)	
Gifts	(4,719)	
Promotional	(54,230)	
Civic Activity	(12,335)	
Total FERC 580	**(108,477)**	
FERC 593		
Catering	(791)	
Promotional	(2,449)	
~~Civic Activity~~	~~(51,356)~~	~~Payment for a contract Forester (Washington Forestry Consultants, Inc.) as part of PGE's tree trimming costs. PGE has added a FTE for this function, but has not provided any documentation of removal of this cost from its budget.~~
Total FERC 593	**(3,240)**	
Total FERC 5XX	**(111,961)**	

UE 197 PGE - Oregon & Montana Property Tax

PGE's 2009 Property Tax Expense

2007 Actual Montana/Oregon Property Tax Expense	31,971,241	
Remove PW Expense in 2007 Actuals	$ (1,212,985)	
Adjusted 2007 Actual Property Tax Expense	$ 30,758,256	
2007 Actual Average Rate Base per 2007 ROO	$ 1,939,421,000	
Ratio of 2007 Property Tax Expense to Rate Base	1.58595%	
PGE Filed 2009 Average Rate Base	$ 2,365,737,000	
Less Estimated Biglow I rate base	$ (225,000,000)	
2009 Rate Base w/o Biglow	$ 2,140,737,000	
Non Biglow Estimated 2009 Property Tax expense	$ 33,951,028	Apply 1.59% to 2009 Non-Biglow RB
Add Biglow Property Taxes	$ 2,000,000	
Estimated 2009 Property Taxes	$ 35,951,028	
2009 Montana/Oregon as filed by PGE	36,929,974	
PER PGE Adjustment to 2009 Montana/Oregon Property Taxes	**$ (978,946)**	

STAFF'S 2009 PROPERTY TAX EXPENSE USING A REVISED PGE METHOD

2007 Actual Montana/Oregon Property Tax Expense	31,971,241
Remove PW Expense in 2007 Actuals	$ (1,212,985)
Adjusted 2007 Actual Property Tax Expense	$ 30,758,256
2007 Actual Average Net Utility Plant per 2007 ROO	$ 2,061,635,000
Remove 50% PW ($280,090,000 X 50%)	$ (140,045,000)
Adjusted 2007 Average Net Utility Plant	$ 1,921,590,000
Ratio of 2007 Property Tax Expense to Net Utility Plant	1.60067%
PGE Filed 2009 Average Net Utility Plant	$ 2,497,795,000
Less Estimated Biglow I rate base	$ (225,000,000)
Remove PW and estimated accumulated depreciation	$ (270,753,667)
2009 Net Utility Plant w/o Biglow 1 or Port Westward	$ 2,002,041,333
Non Biglow Estimated 2009 Property Tax expense	$ 32,046,014
Add Biglow Property Taxes	$ 2,000,000
Estimated 2009 Property Taxes	$ 34,046,014
2009 Montana/Oregon as filed by PGE	36,929,974
Adjustment to 2009 Montana/Oregon Property Taxes	**$ (2,883,960)**

Notes

1. Rather than calculating a ratio of property taxes to total rate base, Staff calculates a ratio of property taxes to net utility plant.
2. Staff adjusted the 2007 gross plant and depreciation to remove Port Westward. In calculating the ratio of property taxes to net utility plant, the numerator (property taxes) does not include Port Westward, therefore the denominator (gross plant net of depreciation) also should not include Port Westward
3. Staff adjusted the 2009 gross plant and depreciation to remove the plant/depreciation associated with Port Westward, as no property taxes will be paid during the test year.

CASE: UE 197
WITNESS: Dustin Ball

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 902

Exhibit in Support of Testimony

September 15, 2008

May 19, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated May 1, 2008
Question No. 300

Request:

Please identify the 2007 actual and forecasted 2009 weighted average Health and Dental program premiums, as discussed in UE 197/PGE 800, Barnett – Bell/14, without factoring in any employer/employee sharing. Please also provide a breakdown of the weighted average Health and Dental program premiums between union and non-union.

Response:

There are seven separate coverage options under the Health and Dental active non-union plans. 1,785 employees were eligible for this coverage in June 2007. Total premium costs in 2007 were $19,041,514 for employer and employee shares. Using the 1,785 employee count, the 2007 total average premium cost for this group was approximately $10,668. PGE's forecasted contribution to these coverage options in 2009 is $19,042,599 (employer only share). PGE targets an 85/15 employer/employee sharing of health and dental premium costs; consequently, PGE's 2009 total program premium costs would be approximately $22,403,058 (employer and employee share).

For employees in the main bargaining unit, PGE only knows the amount it pays and is not able to calculate a weighted average cost. PGE contributes a fixed amount per hour for bargaining employees to an Employee Beneficial Association Trust as described in PGE's response to OPUC Data Request No. 255. PGE's total contribution for 2007 active and retiree health and welfare costs was $10,056,070 (see OPUC Data Request No. 256). These costs are broken down between active ($9,244,620) and retiree ($811,450) costs. PGE had 843 active union and 528 retiree union employees as of Jun 30, 2007. Using these employee counts, PGE's total weighted average contribution to active union employees was $10,966 and to union retirees was $1,537 per employee

September 03, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated August 19, 2008
Question No. 421

Request:

As a follow up to DR No. 376, please provide a breakdown of actual Employee Wellness Program costs for January through July 2008, broken down by month and into the same ledgers and cost descriptions as shown in PGE's response to DR No. 376. Please also provide a monthly breakdown of these same ledgers and cost descriptions for 2007.

Response:

Attachment 421-A provides details regarding actual Employee Wellness Program costs incurred, by month, for January through July 2008. Please note that these costs are seasonal in nature and tend to be relatively small during the first part of the year.

Attachment 421-B is a breakdown of actual Employee Wellness Program costs incurred, by month, for 2007.

UE 197
Attachment 421-A

Employee Wellness Program

N44473 - Employee Wellness Programs

Description	2008							
Occupational Health								
Ergonomics & Integrated Absence Mgmt	Jan	Feb	Mar	Apr	May	Jun	Jul	Total
Occupational Fitness	779	2,194	3,796	6,909	15,804	78,521	23,477	**131,479**
Employee Training	7,469	1,422	346	899	1,597	708	-	**12,440**
Other	3,775	3,405	4,588	3,710	4,228	3,735	2,974	**26,415**
Total Miscellaneous Benefit Costs	75	370	1,055	70	609	50	666	**2,895**
	-	-	1,440	-	160	-	-	**1,600**
	12,097	**7,391**	**11,225**	**11,588**	**22,397**	**83,013**	**27,117**	**174,829**

Note: Costs are PGE share

Staff/902
Ball/4

UE 197
Attachment 421-B

Employee Wellness Program Costs Incurred

N44473 - Employee Wellness Programs

Description
Occupational Health
Ergonomics & Integrated Absence Mgmt

	2007												
Occupational Fitness	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Employee Training	1,281	3,768	2,137	9,023	9,327	19,130	84,643	12,048	10,249	16,748	7,073	12,861	**188,287**
Other	-	-	-	-	-	-	-	264	-	32,234	324	165	**32,986**
Total Miscellaneous Benefit Costs	2,795	4,769	3,157	3,469	4,567	3,099	4,700	5,385	3,265	2,967	4,919	3,111	**46,204**
	444	344	1,558	727	2,357	511	-	79	466	(15)	20	35	**6,526**
	-	308	-	-	3,150	140	-	-	-	1,470	-	-	**5,068**
	4,521	**9,189**	**6,851**	**13,219**	**19,402**	**22,880**	**89,342**	**17,776**	**13,979**	**53,404**	**12,335**	**16,172**	**279,071**

Note: Costs are PGE share

April 15, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated March 25, 2008
Question No. 102

Request:

Please quantify the following cost reductions, and show how (and to what extent) the implementation of an Integrated Absence Management Program has been included as a reduction to projected 2009 costs.

Response:

The Integrated Absence Management (IAM) program was launched on 10/1/2007 to provide a more efficient, centralized, and collaborative approach to absence management within PGE.

A cost reduction analysis from PGE's IAM program is not available. We are currently developing key metrics for the program to monitor the direct and indirect costs as well as indicators of IAM effectiveness. PGE expects that long-term costs will decrease and we may see some short-term intangible benefits by reducing the days away from work through increased efficiency managing absences, providing return-to work assistance, and improving the use of health care resources during recovery periods. Additionally, we will collect and act on employee feedback in an effort to continuously improve the efficiency and value of the program.

May 8, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated May 1, 2008
Question No. 299

Request:

Please provide, in a table format, a breakdown of the forecasted $1,054,000 in miscellaneous benefits costs for 2009. Please also provide a breakdown of the 2005 through 2007 and estimated 2008 miscellaneous benefits costs in this same table. Please explain the reason for any annual increases in a specific cost category (i.e. education assistance, service awards, etc) which exceed 10%.

Response:

Attachment 299-A provides a breakdown of 2005 through 2007 and estimated 2008 and 2009 miscellaneous benefits cost.

Colstrip Charge-Back (36.8%) – PGE co-owns the Colstrip 3 & 4 generation plants and is "charged-back" a lump sum for health care premiums and other benefits for PGE's share. The 2009 forecast reflects an increase in these benefits costs.

Health Club Reimbursement (NA) – This program supports our Energy for Life program. PGE believes that promoting a healthy work force reduces long-term medical costs, and attendance-driven partial reimbursement supports this goal. The health club reimbursement program is not a new cost, and the percentage increase from 2005 does not reflect 2005 costs. Prior to 2007, costs were recorded as a payroll expense. Total costs increase from 2007 because PGE has expanded the eligibility of the programs to include non-traditional health and wellness club activities (e.g., Yoga, Pilates, Tai Chi, etc).

Commuter Program (14.6%) – PGE supports transportation fairs which promote alternate forms of employee commuter transportation methods. Each Transportation Fair features a variety of transportation experts from area agencies and businesses.

Service Awards (21.9%) – As a retention strategy, PGE honors employees for their years of service at five year anniversary intervals. PGE has been below the industry standard for a long time and in 2008 and 2009 we increased the budget to bring our Service Awards program closer to market. Attachment 299-B provides a comparison of the average dollars spent on employee recognition for 7 energy utilities (combined) and PGE's previous average dollars spent on employee recognition.

Retiree Association and Retiree Luncheon (NA) – PGE supports the Retiree Association and sponsors a retiree luncheon to honor PGE's employees who have served the company. These costs were not recorded to a specific benefit job in 2005.

Executive Financial Planning (NEW) – PGE's total compensation for executives provides this benefit.

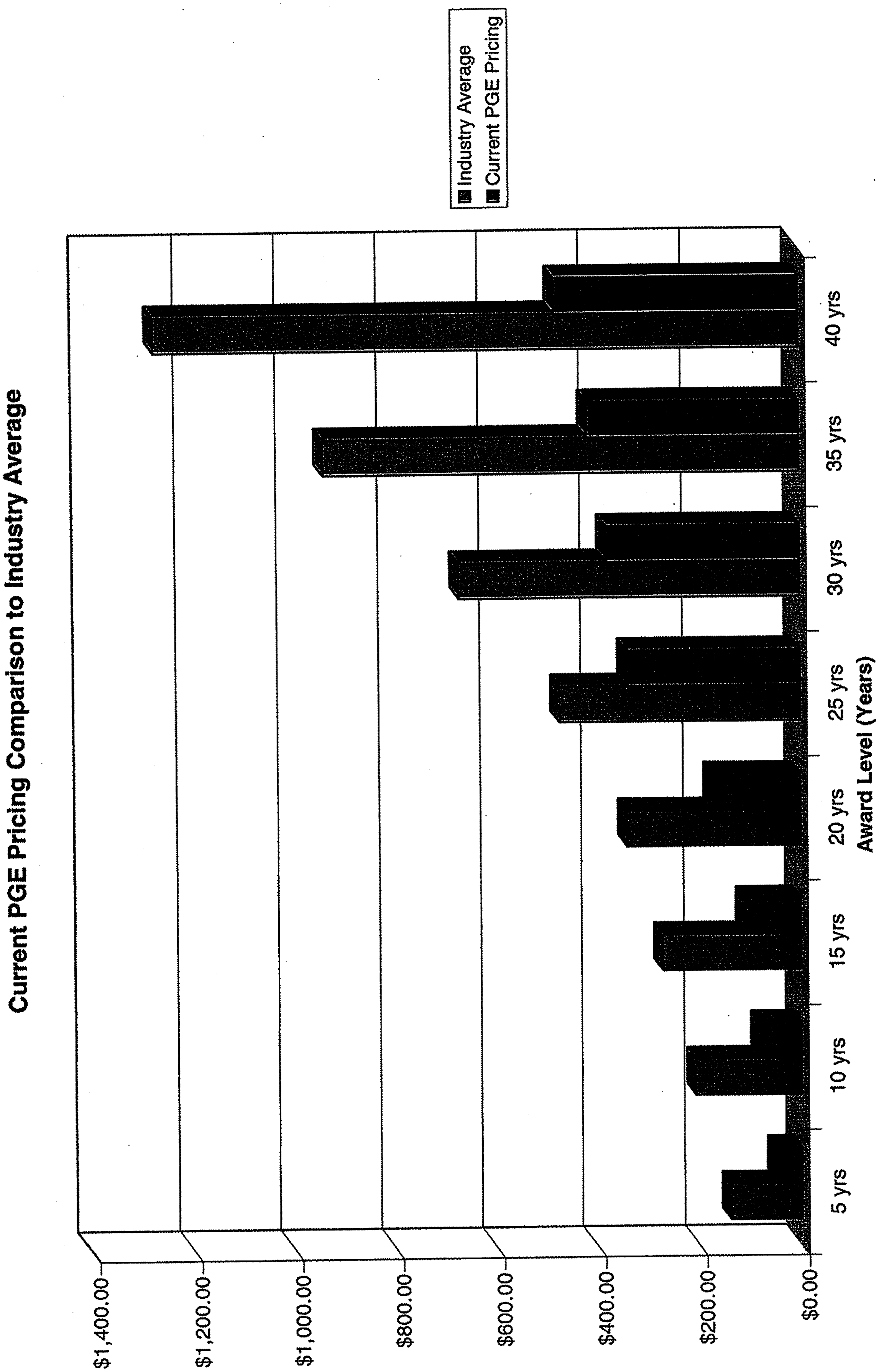
UE 197
Attachment 299-A

Miscellaneous Benefits Costs

UE 197
Attachment 299-B

Comparison of Market and PGE
Service Award Costs per Employee

Ledgers and Cost Descriptions	2005 ACTUALS	2006 ACTUALS	2007 Actuals	2008 FOM	2009 FOM	Annual % Change 2005 - 2009
N44457-EDUCATION PROGRAM Total	458,870	494,949	532,736	453,340	485,074	1.4%
N44454-RECREATION PROGRAM Total	23,241	19,244	18,749	25,000	25,825	2.7%
N44459						
Colstrip Charge-Back	39,847	30,067	73,043	116,000	139,400	36.8%
Health Club Partial Reimbursement	0	0	49,905	100,000	100,000	N/A
Commuter Program	14,549	17,604	6,475	25,101	25,101	14.6%
Service Awards	102,053	93,443	84,442	100,000	225,000	21.9%
Retiree Association and Retiree Luncheon	0	2,500	11,862	13,200	13,200	N/A
Executive Financial Planning	0	0	0	31,500	31,500	NEW
Other	34,678	19,002	74,726	9,315	9,315	-28.0%
N44459 - MISCELLANEOUS EMPLOYEE BENEFIT Total	191,126	162,615	300,454	395,116	543,516	29.9%
Total Miscellaneous Benefits	673,237	676,808	851,938	873,456	1,054,415	11.9%


Current PGE Pricing Comparison to Industry Average
Industry Average
Current PGE Pricing
$1,400.00
$1,200.00
$1,000.00
$800.00
$600.00
$400.00
$200.00
$0.00
5 yrs
10 yrs
15 yrs
20 yrs
25 yrs
30 yrs
35 yrs
40 yrs
Award Level (Years)

July 21, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated July 14, 2008
Question No. 413

Request:

As a follow up to DR No. 66, please provide copies of the updated property and workers compensation insurance premiums which expired on July 1, 2008 (Policy #'s UW158-FM, L0119A1A07-AEGIS, NRS10710135, L0119A2A07, and XWC 464-4193).

Response:

Please see Attachments 413-A, 413-B, 413-C, 413-D, and 413-E which are confidential and subject to Protective Order No. 08-133. The policy numbers listed in the question above have been changed with the renewal of the new policies and are listed in Attachment 413-A

UE 197
Attachment 413-A

Confidential and Subject to Protective Order No. 08-133

Renewed Property Insurance Policies

This page is confidential.

You must have signed the protective order in this docket in order to view this page.

PORTLAND GENERAL ELECTRIC COST ALLOCATION MANUAL FOR THE YEAR 2007

Introduction

This document discusses PGE's loadings, allocations and the respective methodologies that are used to redistribute costs to non-regulated activities and affiliates. For some services, typically those that benefit various functional areas, it is not practicable to charge the cost directly. Costs that cannot be reasonably direct charged are captured either on the balance sheet through deferred ledgers or in specific income statement ledgers (base accounts). These costs are then redistributed to their ultimate distribution.

PGE uses a series of automated reclassifications and loadings to distribute administrative and overhead costs to end use accounts. There are four groups of these: 1) Labor Loadings, 2) Service Provider Allocations, 3) Administrative Allocations, and 4) Overhead Loadings.

2007 Corporate Allocation Summary	
Trojan	0.99%
Boardman	5.54%
Coyote Springs	1.03%
Pelton Round Butte	2.13%
Portland General Resource Development	0.00%
Salmon Springs Hospitality Group	0.23%
Portland General Electric Foundation	0.03%
World Trade Center Northwest	0.00%
Utility Capital	43.90%
Utility Expense	44.36%
Non-Utility	1.79%
Total	**100.00%**

The total pool of overhead dollars in 2007 was $246,195,797.84, of which $154,595,795.16 was allocated to capital, deferred, non-utility, and other expense ledgers. All unallocated dollars remain in their respective A&G or O&M ledgers.

PGE's Non-Regulated Activities

Non-Regulated Activities:

- Utility Asset Management
- Efficiency Services
- Electrical Equipment Services
- Power Quality Products
- Large Nonresidential Tradable Renewable Resources
- Service Maps

Transforming Urban Portland...

...One Student

at a Time

Corporate Internship Program

How It Works

In its most basic sense, the CIP program works as follows:

Students + Sponsors = Education

Without our sponsors, families would not be able to afford the private school costs of De La Salle North Catholic High School. With the sponsors' support, students are able to help finance their own quality, college prep education.

- **Students work in job sharing teams to cover a standard business week, Monday through Friday.**
- **Students work an eight hour day from the time they arrive until the time they leave (i.e. 8:30-4:30 or 9:00-5:00)**
- **Academic schedules are structured so that students are available to work without missing class.**
- **Each student works five full days per month**
- **Sponsoring Companies contract with the Corporate Internship Program to fill full-time, entry level jobs in their offices.**
- **Students are employees of the Corporate Internship Program, NOT THE SPONSORING COMPANIES.**
- **The Corporate Internship program handles all payroll, W-4, I-9,Workers' Compensation, FICA, and other employer issues for the students.**
- **The program runs annually from Labor Day through the third week of June.**
- **Students assign their earnings to De La Salle North Catholic High School to pay for 70% of the cost of their education.**
- **Students receive a college preparatory education they previously could not afford while gaining valuable job experience.**

Staff/902
Ball/18

April 22, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated March 25, 2008
Question No. 094

Request:

Please provide a breakdown of the estimated locating expense for 2009. What portion of the projected $700,000 increase is due to the higher contract cost, and what portion is due to the projected increase in Locating requests?

Response:

2009 Projected:

Locating Requests	Costs
136,500	$1,787,197.00

Approximately 95% of the projected cost increase is due to the higher contract cost. The remaining portion of the cost increase, approximately 5%, is due to the projected increase in locating requests.

April 15, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated March 25, 2008
Question No. 099

Request:

Please describe the protective clothing that will be purchased in 2009 to mitigate Arc-flash? What is the useful life of the items that will be purchased?

Response:

Clothing will consist primarily of specialized shirts and pants with additional coveralls and outer wear as needed to protect the worker. Garment life is impacted by weight of material and type of manufacturing process used. Industry tests tell us that the material we are considering for wear trials could last as long as 3-5 years.

ITEM NO. 3

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: August 26, 2008

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** NA

DATE: August 15, 2008

TO: Public Utility Commission

FROM: Jerry Murray

THROUGH: Lee Sparling, Ed Busch and JR Gonzalez

SUBJECT: AR 528: Initiate a rulemaking to modify OAR 860-024-0010 to delay the effective date for the Arc Flash Protection Rule for twelve months.

STAFF RECOMMENDATION:

Staff recommends that the Commission initiate a rulemaking to modify OAR 860-024-0010, as detailed in Attachment A. Staff's proposed rule would allow a twelve-month delay of the January 1, 2009, effective date for the National Electrical Safety Code (NESC) Rule 410.A.3 (commonly known as the "Arc Flash Protection Rule").

DISCUSSION:

This requested rulemaking would be a continuation of Docket AR 513, which adopted the 2007 edition of the NESC as the minimum construction, operation, and maintenance standard for Oregon electric supply and communication operators on May 17, 2007. In its Order 07-179 adopting the 2007 edition of the NESC, the Commission also directed Staff to perform an investigation into the new arc hazard rules found within Part 4 (Rules for the Operation of Electric and Communications Lines and Equipment) of the NESC. The Commission Order read:

> *". . . Staff should review the impacts of the new arc-hazard standards covered in NESC Rules 410A3 and 420I2, and should specifically consider the effective implementation date and provide a recommendation by August 1, 2008. Commission Staff may also consider conflicts with federal and Oregon OSHA regulations, as well as cost impacts on affected utilities, operators, and interested*

persons in the course of its review or in a subsequent review. Workshops should begin on or after June 1, 2008, so that utilities have time to conduct their internal reviews."

The Arc Flash Protection Rule is the only requirement within the 2007 NESC that has a delayed effective date. The Rule's effective date was originally delayed to allow utilities and employers additional time for facility assessments and for making decisions on how electrical workers need to be protected against arc flash hazards. NESC Rule 420.I.2 further requires employees to wear clothing or clothing systems as directed by their employers.

As mandated by the Commission Order 07-179, Staff has conducted and concluded its investigation into this matter. Staff's investigation included an industry workshop and meetings with affected parties. In addition, Staff requested and received written comments from electric utilities, labor unions, contractors and other interested parties on implementation issues associated with the Arc Flash Protection Rule. Interested parties may review the records associated with Staff's investigation at the PUC's Safety website.[1]

Staff began its Arc Flash Protection Rule investigation with a panel presentation before the Oregon Utility Safety Committee (OUSC) on May 16, 2008. The OUSC has over 200 members who are utility safety officials from throughout Oregon. Representatives of Portland General Electric (PGE), PacifiCorp, Oregon OSHA, PUC Staff and others served as panel speakers. OUSC members were advised of the June 17 Arc Flash Workshop (hosted by Staff) and the need to provide written comments to Staff to justify a PUC rulemaking proceeding.

On June 17, 2008, Staff held an industry workshop on the Arc Flash Protection Rule in the PUC's Main Hearing Room. AR 513 interested persons, members of the OUSC and the Oregon Joint Use Association (OJUA), representatives of utilities and others attended the workshop. A number of issues associated with the Arc Flash Protection Rule were raised at the workshop including: possible errors in the NESC tables, selection of assessment methodologies and software, employee and contractor training, availability of resources (including fire retardant clothing), and liability concerns. PGE, PacifiCorp, and the Oregon electric cooperatives made it clear that the PUC should initiate a rulemaking to delay the implementation date provided in the Arc Flash Protection Rule.

In follow-up to the workshop, Staff received numerous written comments from various interested parties.[2] All utilities that provided written comments and the

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1 See PUC Website at *http://www.puc.state.or.us/PUC/safety/nescreview.shtml.*
2 See PUC Website at *http://www.puc.state.or.us/PUC/safety/arcflash.shtml.*

Oregon Rural Electric Cooperative Association (ORECA) submitted arguments supporting a delay in the Arc Flash Protection Rule. PGE stated a delay of six months to a year was necessary. Local Union #659 of the International Brotherhood of Electrical Workers (IBEW) submitted comments opposing any delay. IBEW 659 stated that electrical workers deserve the protection mandated by the NESC Arc Flash Protection Rule, including arc flash protection training.

In response to the above comments, on July 17, 2008, Staff sent an e-mail message to all interested parties recommending a PUC rulemaking proposal to delay implementation of the Arc Flash Protection Rule for an additional six months. In the same e-mail Staff asked for comments as to the acceptability of the proposal and other information that would justify a PUC rulemaking. Staff only received two written comments in response.[3]

One was from McIntosh Utility Services and Training (MUST), a provider of safety training and consulting services to utilities and other employers about electrical worker safety matters. MUST recommended a full one-year extension to allow utilities and employers enough time to (1) complete facility assessment studies, and (2) provide employees with appropriate arc flash protection.

PGE also provided written comments indicating an extension beyond six months was appropriate in order to allow the possibly erroneous NESC tables within the Arc Flash Protection Rule to be corrected and to allow for the development of industry consensus policies and training on this matter. PGE stated the delay would afford the company more time to make prudent decisions in meeting the intent of the Rule and to provide more effective funding. Such a delay would also allow more time for federal and Oregon OSHA agencies to provide better guidance about employee arc hazard protection.

Electric utilities stated that the compliance costs associated with the Arc Flash Protection Rule are substantial. For example, PGE estimates that costs for protective clothing and training for its employees will be over $600,000 initially, not including future costs for new employees, ongoing training, and clothing replacement. In addition the company expects to spend about $1,300,000 in 2008, 2009 and 2010 to upgrade existing plant and to provide new equipment to promote compliance with the Rule. Further, Wasco Electric Cooperative (WEC) claims worker clothing program costs vary from $400 to $2,000 per employee depending on the utility assessment methodology chosen.

Staff has completed its investigation into the new Arc Flash Protection Rule and concludes as follows:

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[3] See written comments nos. 12 and 13 at PUC Website *http://www.puc.state.or.us/PUC/safety/arcflash.shtml*

- A significant number of Oregon electric utilities and organizations are adamant that an additional delay of six to twelve months is necessary for implementation of the Arc Flash Protection Rule. Electric utilities requesting the delay include: Consumers Power, Oregon Trail Electric Cooperative, PacifiCorp, Portland General Electric, and Wasco Electric Cooperative. Other organizations requesting a delay include International Line Builders, McIntosh Utility Services and Training, and the Oregon Rural Electric Cooperative Association.

- The International Brotherhood of Electrical Workers (IBEW), both the national organization and Local Union No. 659, are opposed to the PUC delaying the implementation of the Arc Flash Protection Rule. The IBEW's position is that electrical utilities and industry have had more than enough time to prepare and achieve compliance with the Arc Flash Protection Rule.

- ORECA and Oregon electric utilities allege that NESC table 410-2 within the Arc Flash Protection Rule contains errors. The NESC Subcommittee 8, which has national standard oversight responsibility for the Arc Flash Protection Rule, has supposedly corrected the errors; however, these corrections will not be published as an official amendment to the NESC until later this year. Parties claim this fact alone justifies a delay in the implementation of the Arc Flash Protection Rule.

- The Arc Flash Protection Rule will cause significant cost impacts to Oregon's electric utilities. PGE alone will incur over the next three years about $2,000,000 in increased capital and operating costs in complying with the Arc Flash Protection Rule. Other electric utilities and electrical employers will incur significant costs in providing arc flash protection to workers. A delay will allow utility safety officials more time to interact together to develop better and more uniform clothing and protection schemes to protect electric workers against arc flash hazards.

- Federal OSHA may in the future issue regulations and guidance about how electrical workers need to be protected with personal protective equipment (PPE) against arc flash hazards. However, Staff believes such future Federal OSHA regulations will not be in conflict with the NESC Arc Flash Protection Rule. Unlike OSHA regulations, the NESC does not mandate whether the employer or employee must supply and pay for the necessary PPE. The NESC only requires that utilities or employers perform facility assessments and give instruction to their employees as to the levels of arc flash protection necessary.

- Arc flash clothing and clothing systems today offer electrical workers proven life-saving protection against electric arc exposure. There has been considerable innovation in the last 10 years on fire-retardant clothing. Staff believes electrical workers need to be trained in the use of such clothing. Staff believes that delaying implementation the Arc Flash Rule beyond January 1, 2010 would be unacceptable and would put electrical workers at unnecessary risk of death and serious injury.

- Staff did not appreciate the potential impact of the Arc Flash Protection Rule upon the electrical utility industry and the PUC when the 2007 NESC was first adopted into Oregon law in May of 2007. During the investigation process Staff discovered it may not have the personnel to review the implementation of, and to enforce the Arc Flash Protection Rule when implemented. Additional tasks and responsibilities which may be required of Staff, include:
  - Review of facility arc flash exposure assessments by utilities,
  - Review associated utility work practices,
  - Audit utility facilities for posted signage,
  - Review selection of worker clothing and clothing systems,
  - Review employee and contractor training, and
  - Perform field verifications of clothing usage by crews.

  To accomplish the above tasks, Staff may need additional resources.

Michael Weirich, ODOJ, supported Staff in the investigation and informal rulemaking process. Michael also attended the Staff-industry workshop held on June 17, 2008. He also approved the language provided in Attachment A from a legal perspective.

In summary, Staff recommends the Commission initiate a rulemaking that would delay the effective date of the NESC Arc Flash Rule from January 1, 2009 until January 1, 2010.

PROPOSED COMMISSION MOTION:

Initiate a rulemaking to amend OAR 860-024-0010 as described in Attachment A to Staff's Report.

Attachment A

Attachment A

Oregon Administrative Rule

860-024-0010

Construction, Operation, and Maintenance of Electric Supply and Communication Lines

(1) Except as provided in section (2), ~~E~~every operator shall construct, operate, and maintain electrical supply and communication lines in compliance with the standards prescribed by the 2007 Edition of the National Electrical Safety Code approved June 16, 2006, by the American National Standards Institute.

(2) Rule 410.A.3 of the 2007 Edition of the National Electrical Safety Code will not become effective until January 1, 2010.

September 03, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated August 19, 2008
Question No. 428

Request:

What was PGE's cost per distribution line mile for tree trimming in 2004, 2005, 2006, 2007, and forecasted for 2008 and 2009. Please show the number of miles used to compute the cost per mile. Please also explain any significant (greater than 8 percent) increase/decrease between years.

Response:

The following chart shows actual costs for distribution line miles trimmed for the years 2004 through 2007 and projected costs for 2008 and 2009. The actual numbers have previously been reported to Staff as Service Quality Measurements.

Year	Actual Miles Trimmed	Actual CPLM
2004	3523	$1,926
2005	3464	$1,968
2006	3627	$2,424
2007	3777	$2,532
2008 Projected	**4500**	**$1,900**
2009 Projected	**4500**	**$2,100**

The overall increase in cost per line mile costs for 2006 and 2007 can in part be attributed to the national and regional shortage of qualified line workers. For example, from 2006 into 2007, PGE's tree trimming contractor lost a total of 42 employees out of a normal compliment of 95 employees. These employees chose other occupations, moved out of the area, or went into the lineman apprenticeship program in IBEW Local 125. Sixteen of these employees were journeymen tree trimmers, and the remainder were tree trimming apprentices in various levels of their apprenticeships. Due to the shortage of tree workers nationally, it has been difficult for the contractor to fill these vacancies with qualified employees. The lack of a fully trained and qualified workforce has a dramatic impact on the cost per line mile performance measurements.

We have also experienced more restrictive policies related to working on county and Oregon State highways that have impacted operating costs. There have been policy changes on which roads now require flag-persons as well as policies that limit the work hours that tree crews can be blocking lanes for each day of the week.

However, it should be noted that there are any number of possible reasons for cost per line mile numbers to have a greater than 8% increase or decrease from project to project or from year to year. Factors such as tree density or the rate of tree re-growth, or the number of tree removals can affect costs. Contractor rates or the amount of flagging or hand work required can impact project costs.

The following chart from PGE's Service Quality Measurements for each year shows the possible range of actual project costs per line mile (CPLM):

	Two-year Areas		Three-year Areas	
Year	Highest CPLM	Lowest CPLM	Highest CPLM	Lowest CPLM
2004	$3,229	$998	$8,784	$1,476
2005	$6,771	$1,999	$3,893	$1,124
2006	$8,729	$992	$5,585	$765
2007	$6,007	$1,435	$5,969	$1,197

A $1,900 cost per line mile was used for developing 2008's budget despite 2006's actual costs of $2,500 in anticipation of contractor and PGE training programs that should result in more qualified and therefore more productive replacement workers. The $2,100 cost per line mile figure for 2009 reflects the anticipated increase in contractor rates.

June 6, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated May 23, 2008
Question No. 384

Request:

Did the 2007 actual tree trimming cost include any additional workload that is not expected to reoccur in 2008 or 2009? Please explain. If so please identify the cost of this additional workload.

Response:

No. The 2007 tree trimming workload levels are expected to be ongoing.

August 1, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE *Supplemental* Response to OPUC Data Request
Dated May 23, 2008
Question No. 383

Request:

What is the annual rate of inflation for tree trimming contracts that PGE has experienced over the past 5 years? How does this relate to PGE's forecasted 2009 amount?

Response:

Attachment 383-A provides the annual rate of inflation PGE has experienced for tree trimming contracts over the past five years. Attachment 383-A is confidential and subject to Protective Order No. 08-133.

Tree trimming budget forecasts for 2009 used an 8% inflation rate. This inflation rate is used due to anticipated increases in contractor equipment rates (due to increased fuel costs), and the anticipated labor wage increase for 2009, which marks the first year of a new labor agreement between the local union and contractor.

Supplemental Response (August 1, 2008):

Please see Attachment 383-B. Attachment 383-B replaces Attachment 383-A. PGE's calculation regarding the 2008 crew rate was incorrect. It has now been corrected. Attachment 383-B is confidential and subject to Protective Order No. 08-133.

UE 197
Attachment 383-B

Confidential and Subject to Protective Order No. 08-133

Tree Trimming Inflation Rates

This page is confidential.

You must have signed the protective order in this docket in order to view this page.

September 03, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated August 19, 2008
Question No. 425

Request:

As a follow up to DR No. 383, please explain how PGE arrived at an 8 percent inflation rate which was used in calculating the 2009 tree trimming budget.

Response:

The current tree trimming contract rates for 2008 increased 8% over the previous year. We expect the two primary factors to continue to increase at the same magnitude between 2008 and 2009. The first consideration was the anticipated increase in the cost of fuel. According to the Oregon Department of Transportation's monthly fuel price records, fuel has increased 85% from 2005 through 2008. While the contractor does not charge PGE directly for the fuel used, this cost is included as a portion of the hourly rate for equipment. Over that same period the rate for a tree trimming bucket truck increased only 5.8%. The effects of the fuel price increases were minimized with concerted efforts by both PGE and our tree trimming contractor to reduce the number of miles driven. Nevertheless, equipment rates will increase due to the significantly higher cost of fuel.

The second consideration was an anticipated increase in contractor labor rates. Typically, because negotiated labor contracts with Local IBEW Union No. 125 and the contractor are for three years, the annual projected increase for contractor labor rates are known and can be accurately budgeted. In the event of a negotiation year, as is the case for 2009, budgeting for the contractor labor rates are projected based on what adjoining local unions have settled. In developing PGE's 2009 tree trimming budget, the negotiated settlement with Local No. 77 (Seattle) for a 6.5% increase on wages was used in projecting the anticipated labor rate increase.

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CASE: UE 197
WITNESS: Ed Durrenberger

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1000

Surrebuttal Testimony

September 15, 2008

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Ed Durrenberger. I am a Senior Analyst in the Electric & Natural Gas Division of the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/401.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to the issues raised by PGE in its rebuttal testimony regarding transmission and distribution operating and maintenance (O&M) costs, general production O&M costs and Fixed Plant O&M costs.

Q. DID YOU PREPARE ANY EXHIBITS SUPPORTING THIS TESTIMONY?

A. No, my testimony concerns facts already in evidence.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I have organized my testimony to discuss the adjustment I proposed in direct testimony. First I will discuss transmission and distribution O&M costs. Then I will respond to the company's position on General Production O&M costs. Finally I will review the fixed plant maintenance cost adjustments.

Q. WHAT IS PGE'S POSITION ON TRANSMISSION AND DISTRIBUTION OPERATING AND MAINTENANCE COST INCREASES?

A. PGE's modified its original requested increase for these costs in its rebuttal testimony. The primary reason for the change is that PGE was able to get better information upon which to estimate the expenses. The company's current position on these costs is in line with the proposal made by Staff in direct testimony. Rather than an increase in transmission and distribution O&M costs of $400,000, the company is now proposing an increase of $250,000.

Q. IS THIS REASONABLE?

A. Yes, I believe it is. The major cost driver for the adjustment is PGE's participation as a full member in the Northern Tier Transmission Group. This is a positive step in the development of a regional transmission organization. The costs of membership appear to reflect what PGE will actually be paying. Another reason for the cost change is that the company has determined that it will not need to do UFM studies in 2009. I find PGE's new proposal, to increase transmission and distribution costs in the test year by $250,000, to be reasonable. This results in an adjustment of $150,000 to the company's original request.

Q. WHAT IS THE NEXT ADJUSTMENT?

A. The next adjustment is one staff proposes to General Production (O&M) costs.

Q. PLEASE EXPLAIN THIS ADJUSTMENT.

A. In its initial filing, PGE requested a $500,000 increase to the general production budget to cover the following:

1. An increase of $100,000 for Reliability Centered Maintenance (RCM) program improvements.

2. An increase of $300,000 in contract labor expenses related to NERC/ WECC compliance procedure development and outside engineering expenses for non-job work.
3. An increase in of $100,000 to cover the costs of unspecified software purchases during the test year.

Q. WHAT DID YOUR DIRECT TESTIMONY RECOMMEND REGARDING THESE COST INCREASES?

A. I recommended that these cost increases be rejected in their entirety because they did not appear to be incremental and were not justified.

Q. HOW DID PGE RESPOND TO YOUR TESTIMONY?

A. Generally, the company responded to my proposed rejection of the cost by restating the arguments made in their direct testimony without adding any new details.

Q. HAVE YOU CHANGED YOUR POSITION ON THESE COST INCREASES?

A. No.

Q. PLEASE EXPLAIN.

A. First, when PGE reassigns existing maintenance personnel to a RCM function it does not appear to be a new incremental activity and does not warrant a special cost increase. Also, compliance activities required by NERC/ WECC are not entirely new. That notwithstanding, I fail to see how the company can know in advance that there will be enough compliance activity to justify the cost increase proposed for 2009 and beyond. Finally, I find that PGE has not justified its request for a budget increase for unspecified software purchases, upgrades and expansions.

Q. WHAT GENERAL PRODUCTION ADJUSTMENT DO YOU PROPOSE?

A. I propose the same general production O&M adjustments I made in my direct testimony. I recommend that the entire $500,000 in general production O&M cost increases requested for the above items be disallowed.

Q. ARE THERE ANY OTHER ADJUSTMENTS THAT YOU WISH TO PROPOSE?

A. Yes, I would like to discuss the adjustment I proposed in my initial testimony related to fixed generation plant O&M.

Q. PLEASE PROCEED.

A. I reviewed the PGE rebuttal testimony regarding my fixed plant O&M adjustment. I find parts of the company's rebuttal testimony to be compelling.

Q. WHAT ARE THE PARTS TO THIS ADJUSTMENT?

A. The first part is determination of the magnitude of the amount that the Boardman, Beaver and Colstrip generation plants' expected maintenance costs are above average. My direct testimony stated that the three one-time maintenance cost increases proposed by the company raised these expenses to a total of $8.4 million larger than normal. This was the number provided in the company's original testimony. In the rebuttal testimony at UE 197/ PGE/ 1800 Quennoz/ 18, the company pointed out that its proposed increase was actually $6.8 million above inflation-adjusted average maintenance costs. I find that PGE's rebuttal testimony more accurately represents the magnitude of the planned, one-time excess maintenance costs and therefore have adopted the $6.8 million as the test period amount above normal maintenance costs. As a result of this revised cost increase request, I believe that my valuation of the normal fixed plant O&M was $1.6 million low and should be raised by that amount.

Q. DID YOU CONSIDER ANY OTHER PGE ARGUMENTS?

A. Yes. The company, at UE 197/ PGE/ 1800 Quennoz/16-17, argues that it is entitled to recover larger than normal, one-time maintenance and that it is both unreasonable and one-sided to assume that the excess costs could be recovered in the future by skimping on maintenance costs in subsequent years. I find the PGE argument to be compelling.

Q. DOES THIS CHANGE YOUR POSITION?

A. Yes, although I don't agree entirely with what PGE has proposed.

Q. PLEASE EXPLAIN.

A. The company's rebuttal testimony at UE 197/ PGE/ 1800 Quennoz/ 18-19 is now requesting to recover the $6.8 million in higher than normal maintenance costs through setting up a regulatory asset account in that amount and amortizing the balance over five years. They propose that the average balance of the regulatory asset value in 2009 be added to the rate base included in the filing. This result would be an amortization cost of $1.4 million per year plus the return on the increase to rate base. The result of this proposal would be that fixed plant O&M costs increased by about $3 million for the test year.

Stated differently, the fixed plant O&M would be $5.5 million lower than requested in the original filing.

Q. WHAT IS YOUR PROPOSAL?

A. I am not in favor of the company being allowed to create a regulatory asset account for excess maintenance costs. I propose the company first adjust fixed plant O&M costs to represent normalized Boardman, Colstrip and Beaver maintenance costs. This would be an increase to fixed plant O&M of $1.6 million for the test year. Next, I estimate that the excess costs expected for the 2009 test year will reoccur again with a regularity of about once in every ten years. Consequently, I propose an additional increase to annual fixed plant O&M costs of an amount equal to one tenth of the excess $6.8 million, thereby insuring that the budget allows for full recovery of these infrequent excess maintenance expenses that occur with the ten year regularity. The result of my proposal would be a fixed plant O&M budget increase of $2.3 million for the test year, a reduction of $6.1 million to the overall fixed plant O&M that PGE requested in its original filing.

Q. DO YOU HAVE ANY OTHER ADJUSTMENTS TO DISCUSS?

A. No, that is all.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

CASE: UE 197
WITNESS: Lisa Gorsuch

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Surrebuttal Testimony

September 15, 2008

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Lisa Gorsuch. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found on Exhibit Staff/1101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will provide Staff's response to Mr. Colton's direct testimony on behalf of Community Action Partnership of Oregon (CAPO/OECA) and the Oregon Energy Coordinators Association (CAPO/OECA) in exhibit 200 regarding the following four issues:

1. Late Payment Visit Charge

CAPO/OECA's proposal to exempt low-income customers from payment (*See* CAPO/OECA/200, Colton/30-31); and

CAPO/OECA's proposal to allocate late payment charge revenue for purposes of low-income assistance to residential customers with administration by a third-party (*See* CAPO/OECA/200, Colton/35-36).

2. Monthly Service Charge

CAPO/OECA's proposal to disallow imposition of the monthly fixed customer service charge when service is disconnected for credit-related reasons (*See* CAPO/OECA/200, Colton/47-49).

3. Reconnection and Field Visit Charges

CAPO/OECA's proposal to eliminate or, at a minimum, exempt low-income customers from payment of the charges (*See* CAPO/OECA/200, Colton/ 36-47).

4. Tariffed Budget Billing Plan

CAPO/OECA witness Colton's conclusion that low-income customers do not have access to a Budget Billing Plan (*See* CAPO/OECA/200, Colton/26-30).

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/1101, consisting of one, page. This exhibit contains my witness qualification statement.

Q. WILL YOU BE ADDRESSING MR. COLTON'S PROPOSAL REGARDING AN IMPOSED RATE FREEZE ON THE INITIAL BLOCK OF RESIDENTIAL CONSUMPTION?

A. No. This proposal will be addressed by Staff witness George Compton.

Q. WILL YOU BE ADDRESSING MR. COLTON'S PROPOSAL REGARDING DECOUPLING?

A. No. This proposal will be addressed by Staff witness Steve Storm.

Q. DO YOU AGREE MR. COLTON'S RECOMMENDATIONS RELATED TO PORTLAND GENERAL ELECTRIC'S (PGE) LATE PAYMENT, RECONNECTION, FIELD VISIT, AND MONTHLY SERVICE CHARGES (MISCELLANEOUS CHARGES) ARE APPROPRIATELY ADDRESSED IN THIS PROCEEDING (*SEE* CAPO/OECA/200, COLTON/21-25, 37-49)?

A. No. Currently, PGE’s policies related to miscellaneous charges and the applicability of continuing Monthly Service Charge during voluntary disconnection are in accordance with long-standing Commission policies applicable to all energy utilities. Parties representing a wide range of interests, including those of low-income customers, participated in the proceedings that set those policies.

Q. DOES PGE CHARGE THE MONTHLY SERVICE CHARGE FOR A PERIOD OF TIME WHEN SERVICE IS NOT RECEIVED DUE TO DISCONNECTION FOR CREDIT-RELATED REASONS VERSUS VOLUNTARY DISCONNECTION OF SERVICE?

A. No. As stated in PGE/2000, Kuns – Cody – Lynn/41, customers disconnected for credit-related reasons are not required to pay the monthly service charge for the period of time they are without service. By contrast, when customers have voluntary disconnection of service and then re-establish at the same service address months later, the Commission-supported requirements, standard among many utility companies (including PGE), is to hold those customers responsible for the monthly service charges for periods of time when service is not received.

Q. DO YOU AGREE WITH MR. COLTON’S CHARACTERIZATION THAT PGE’S MISCELLANEOUS CHARGES ARE NOT COST-BASED AND THUS ALLOW PGE TO OVERCOLLECT AND PROFIT FROM THESE CHARGES (*SEE* CAPO/OECA/200, COLTON/23-26, 38-49)?

A. No. When PGE or any other investor-owned energy utility files a proposed tariff related to a miscellaneous fee (e.g. late payment charge, reconnection charge, field visit charge, etc.), Staff reviews the utility-provided workpapers to ensure that the amount of the charge is justified by the level of expense incurred by the utility. But, that is not to say that all tariffed miscellaneous charges are cost-based. For example, for all of the energy utilities (including PGE), actual expense to reconnect a customer's service exceeds the tariffed reconnection charge because there is a conscious decision to mitigate the impact on low-income customers. The difference between the tariffed amount of the reconnection charge and the associated expense is spread to all rate payers to avoid imposing a hardship on low-income customers.

Q. DO YOU AGREE WITH MR. COLTON'S TESTIMONY THAT LOW-INCOME CUSTOMERS ARE NOT ALLOWED ACCESS TO BUDGET BILLING PLANS (*SEE* CAPO/OECA/200, COLTON/26-30)?

A. No. PGE offers three Budget Billing Plans, two of which are geared to customers with overdue account balances as required by OAR 860-021-0415, and the one discussed by Mr. Colton that is offered to customers with a zero account balance as required by OAR 860-021-0414.

Q. WILL PGE INCREASE SCHEDULE 300 CHARGES (I.E. FIELD VISIT CHARGE, RECONNECTION CHARGE, ETC.) AS A RESULT OF UE 197?

A. No. PGE will not request an increase of Schedule 300 charges at this time as part of a stipulation regarding certain revenue requirement issues filed with the

Commission on August 5, 2008. All of PGE's Schedule 300 charges will be held at current levels with regard to UE 197.

Q. DO YOU HAVE ANY RECOMMENDATIONS FOR FURTHER REVIEW OF THE ABOVE ISSUES?

A. Yes. The appropriate forum to address CAPO/OECA's issues is within the context of an energy industry-wide investigation about the impact of utility policies regarding rate structures and fees on low-income customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 197
WITNESS: Lisa Gorsuch

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Witness Qualification Statement

September 15, 2008

WITNESS QUALIFICATION STATEMENT

NAME:	Lisa Gorsuch
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst/Rates & Tariffs
ADDRESS:	550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.
EDUCATION:	College-level coursework in financial accounting, business law, business management, and economics. The Center For Public Utilities at New Mexico University. The National Association of Regulatory Utility Commissioners' Annual Regulatory Studies Program at Michigan State University.
EXPERIENCE:	Utility Analyst with the Public Utility Commission of Oregon since April 2008. Primarily responsible for review of electric and natural gas company tariff filings and other electric and natural gas company rates and costs. Provide expertise to Consumer Services Division on consumer-related issues. Compliance Specialist with the Public Utility Commission of Oregon from June 2004 until April 2008. Responsibilities included acting as a liaison between the public, regulated utilities and various Commission staff. Review of proposed tariffs, administrative rules, and policies for evaluation of the potential impact on consumers and the regulated utilities. Identified trends, services, and policies where no statute, rule or precedent applied and recommended the appropriate action.
OTHER EXPERIENCE:	Enforcement Agent with the Oregon Department of Revenue as a member of a multijurisdictional task force including Oregon Department of Justice and Oregon State Police from June 1999 until May 2004. Responsibilities included investigating cases of tax evasion involving smuggling of illegal cigarette and other tobacco products. Review of administrative rules, and compliance and enforcement standards for multiple tax programs. Serving as liaison between task force and Oregon State Legislators to determine appropriate tax rate, and legislative concepts for two different tax programs.

CASE: UE 197
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200

Surrebuttal Testimony

September 15, 2008

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is George R. Compton. I am a Senior Economist, employed half time by the Economic Research & Financial Analysis Division (ERFA) of the Oregon Public Utility Commission (OPUC). My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. ARE YOU THE SAME PERSON WHO FILED DIRECT TESTIMONY, EXHIBIT STAFF/500, AND THE ACCOMPANYING EXHIBITS 501-507?

A. I am.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. I will be responding to elements of a) the rebuttal testimony of PGE's Doug Kuns and Marc Cody as found in PGE/2000, b) the direct testimony of Roger Colton on behalf of CAPO/OECA, and c) the direct testimony of Dr. Alan Rosenberg on behalf of ICNU.

Q. IN ITS ORIGINAL APPLICATION PGE PROPOSED TO ADJUST SCHEDULE 125 (ANNUAL POWER COST UPDATE) MAGNITUDES TO REFLECT CHANGES IN FIXED GENERATION COST RECOVERY DUE TO DEPARTING OR RETURNING CUSTOMERS IN SCHEDULES 483 AND 489 (DIRECT ACCESS). PLEASE REMIND US OF STAFF'S REACTION TO THAT PROPOSAL.

A. Staff's voiced concern had to do with the requirement that customers who do not immediately benefit from Direct Access would nevertheless bear a major portion of the risk produced by that program.

Q. HAS PGE ADDRESSED THAT CONCERN IN A RESPONSIVE WAY?

A. It has. PGE's counter-proposal places the entire adjustment on "applicable Large Nonresidential rate schedules (Schedules 75, 76R, 83, 89, 483, 575, 576R, 583, 589)." (*See PGE Exhibit/2001 at 4.*)

Q. DOES THAT COUNTER-PROPOSAL ELIMINATE ALL OF YOUR CONCERNS?

A. No. There should be some kind of rate impact limit, e.g., two to five percent, both upwards and downwards, as to how much this adjustment should be allowed to elevate rates. The amounts outside this cap should not be deferred for later inclusion in rates. Absent a cap, a positive-feedback "death spiral" may be introduced. I refer to a surcharge causing some regular sales customers to switch over to Direct Access, which in turn causes the surcharge to be increased (since it would have fewer sales volumes to be amortized over) and thereby inducing even more sales customers to switch to direct access, and so on until there are no more sales customers left to pay the surcharge. While the Transition Cost Adjustment may be a reasonable inducement to encourage customers to transfer to Direct Access, the compensatory or offsetting surcharge shouldn't be the primary force driving customers away from standard retail service.

Q. CAN WE CONCLUDE THAT STAFF IS GENERALLY OPPOSED TO THE VERY IDEA OF SOME FORM OF MECHANISM TO COMPENSATE FOR CUSTOMERS' LEAVING OR ENTERING DIRECT ACCESS?

A. No. Large industrial customers receive a benefit from the existing Transition Cost Adjustment (TCA). Such may induce more of them to convert to Direct Access than would be the case if the only basis for the conversion was a market price that was lower than the PGE energy charge. The existence of a TCA carries a cost in the form of potential net revenue instability on the part of PGE. The question becomes how, if at all, should PGE be compensated for that burden. Input from ICNU and other customer representatives regarding the value of the TCA and where its burden should lie will be welcomed.

Q. THE MAIN ARGUMENT BY PGE AGAINST STAFF'S SEASONALLY DIFFERENTIATED RATES PROPOSAL IS THAT NOT JUST THE SUMMER, BUT THE WINTER SEASON AS WELL, HAS HIGH LOADS AND PRICES. "THEREFORE [PGE SAYS], ONE COULD ALTERNATIVELY MAKE A CASE THAT PGE SHOULD HAVE HIGHER WINTER PRICES THAN IN THE OTHER MONTHS OF THE YEAR, OR THAT ENERGY PRICES SHOULD BE LOWER IN THE SPRING." (*See PGE/2000, page 3, lines 6-15.)* **DO YOU AGREE?**

A. Yes, with caveats. Staff is very much aware of the fact that prices are lower in the spring. Staff also agrees with the Company that the price for wholesale electricity is higher in the winter than in the spring or fall (but not the summer). While a primary objective of rate design is to reflect marginal costs, it is not the only consideration. There are also practical considerations such as cost of administration, ease in communication to customers, and simplicity. It was in the interest of concerns having been voiced regarding those latter considerations that Staff chose to limit its seasonal recommendation to the season with (1) the highest prices, the summer, and (2) where the price signal can be viewed as the most meaningful, i.e., as relevant to the installation of central air-conditioning (which is at the root of the regional load peak and high prices.) If the Company, CUB, and other concerned parties were to advocate on behalf of three or four seasons for rate design purposes instead of two, Staff would assuredly join them.

Q. FOLLOWING THE SENTENCE I JUST CITED, PGE WENT ON TO REMIND US OF ITS HEAVIEST LOADS BEING IN THE WINTER RATHER THAN IN THE SUMMER, AND THAT MARKET PRICES ARE LOWEST IN THE FALL (WHEN LOADS ARE LOW) AND IN THE SPRING (DUE TO THE HYDRO RUN-OFF). PGE'S ANSWER THEN ENDED WITH "THUS, WE CONCLUDE THAT THE IMPOSITION OF SEASONAL PRICING AND AN ADDITIONAL SUMMER ON-PEAK BLOCK PRICE ARE NOT WARRANTED." ***(SEE PGE/2000, PAGE 3, LINES 11-16.)*** **DO YOU CONCUR WITH THAT LOGIC?**

A. No, I do not. PGE is saying, in effect, that because there are *four* distinct seasons, *none* should be recognized in ratemaking, i.e., that rates should be set as if there were *no* seasons. I would say the logical conclusion instead is that *all* four seasons should be recognized. (Refer back to my previous answer as to the wisdom of imposing more than one additional rates season at this time.) At a minimum, we should differentiate the season that would lead to the most efficiency gains or provide signals where the most stress is placed on current and future costs. In any event, PGE has supported cost-based rates.[1] PGE has also recognized summertime capacity needs and the fact that the highest wholesale electricity prices that PGE faces are not in the winter.[2] In that light, Staff does not understand why PGE appears reluctant to implement what has been across the country the most rudimentary of rate reforms, i.e., the seasonal rate differential.

Q. PGE ALSO OBJECTED TO YOUR SEASONAL PROPOSAL ON GROUNDS THAT YOUR SEASONAL DEMARCATION DOES NOT LINE UP WITH PGE'S. (THEIR "SUMMER" RUNS FROM THE FIRST OF MAY THROUGH TO THE END OF OCTOBER.) THEY SAID THAT HAVING "THE CONFLICTING SEASONAL DEFINITIONS...SUGGESTS THAT THE TOU PRICES WILL NEED TO CHANGE EVEN MORE FREQUENTLY THAN THE STANDARD TARIFF PRICES...." WOULD YOU PLEASE RESPOND.

A. Remedying the conflict would be a trivial matter. Staff's three-month, high-priced season (July through September) could simply be substituted for PGE's. After re-perusing Staff/502 (which shows monthly projected peak and off-peak market energy prices), it would be difficult to justify adding any more months than those three to the summer, high-price season. (Again, this is not to say that other seasons shouldn't be added to the two that now are in place for Schedules 7 and 32.)

[1] See especially PGE/1200, page 4 at 13: "We based the proposed rate schedules, as much as possible, on cost causation;" and PGE/2000, page 13 at 19: "The objective of an allocation methodology is to reflect cost-causation in pricing."
[2] See PGE/2000, page 17 at 4-8.

Q. PGE ALSO RAISED A NUMBER OF OBJECTIONS TO YOUR SEASONAL RATES PROPOSAL HAVING TO DO WITH IMPLEMENTATION MATTERS. TWO OBJECTIONS RELATE TO THE IMPLEMENTATION OF AMI (AUTOMATIC METERING INFRASTRUCTURE). ONE WAS THAT SOME EMPLOYEES ARE AND/OR WILL BE BUSY WITH AMI PROJECT-RELATED TASKS, AND PGE WOULD NOT WANT THEM DISTRACTED WITH A DIFFERENT RATE DESIGN PROJECT. *(SEE PGE/2000, PAGE 5, LINES 15-22, AND PAGE 6, LINES 1-2.)* THE OTHER WAS THAT PGE AND ITS COMMERCIAL AND INDUSTRIAL CUSTOMERS WOULD "HAVE TO INCUR POTENTIALLY COSTLY AND CONFUSING CHANGES IN 2009 AND THEN AGAIN SEVERAL YEARS LATER TO ACCOMMODATE THE POST-AMI IMPLEMENTATION CHANGES." *(SEE PGE/2000, PAGE 6, LINES 8-12.)* WOULD YOU PLEASE ADDRESS THOSE OBJECTIONS?

A. As profit seekers, with power cost adjustments included in ratemaking, utilities can be expected to want to minimize administrative costs. PGE's response is consistent with that consideration. However, cost-based rates is a key consideration in the objective to maximize economic efficiency. As far as commercial and industrial customer confusion is concerned, I believe PGE is selling short the intelligence of both those customers and PGE's own tariff and bill formulations staffs. Having rates that are higher in some seasons of the year than in others does not constitute some unfathomable mystery.

Q. AN "ADDITIONAL CONCERN" VOICED BY PGE IS THAT OVERLAYING SEASONAL AND TIME-OF-DAY PRICING UPON THE SCHEDULE 128

SHORT-TERM TRANSITION ADJUSTMENT "WILL INTRODUCE UNNECESSARY CONFUSION TO POTENTIAL DIRECT ACCESS CUSTOMERS." ***(See PGE/2000/4 at 1.)*** **COMMENT?**

A. There seems to be already a "plethora of quarterly transition adjustments we [i.e., PGE] currently prepare to support direct access." *(See PGE/2000/4 at 2-6.)* The prospect that "PGE *may* [added emphasis] have to resort to monthly Schedule 128 transition adjustments" shouldn't represent an insurmountable barrier against the kind of large-customer/large-load rate design reform that is routine elsewhere in the country. Added complications before a few customers who may or may not elect to cease being sales customers of PGE should not get in the way of the substantial efficiency advantages of moving to cost-based rates on the part of one of the largest load cohorts of PGE.

Q. PGE ALSO IS "CONCERNED WITH THE EFFECT THAT STAFF'S PROPOSAL MAY HAVE ON SEASONAL AGRICULTURAL CUSTOMERS AND OTHER CUSTOMERS SUCH AS WATER PROVIDERS WHO PROVIDE CRITICAL SERVICES AND WHO TYPICALLY CONSUME AT A MUCH HEAVIER LEVEL DURING THE SUMMER MONTHS OF THE YEAR. THESE CUSTOMERS CAN LEGITIMATELY ARGUE THAT ON A COST-CAUSATION BASIS, PEAK PRICING SHOULD OCCUR DURING THE WINTER MONTHS INSTEAD OF THE SUMMER MONTHS." ***(See PGE/2000, page 4, lines 7-12.)*** **COMMENT?**

A. Five points: 1) Cost-causation refers to costs, not loads. The highest peak period prices occur in the summer (July-September), not the winter. (Refer to

Exhibit Staff/502.) 2) PGE's energy/production cost allocation already reflects seasonal, monthly, and peak- versus off-peak marginal cost variations. Staff's *pricing* recommendation would have no effect on the different schedules' *cost*, or revenue requirement, allocation. 3) Given a fixed cost allocation, higher prices in one period are inevitably offset by lower prices in the remainder of the pricing periods. 4) Agricultural irrigation customers (Schedules 47 and 49) are, in any event, protected from extreme revenue requirement allocation increases by the Consumer Impact Offset (CIO) provision of ratemaking. 5) The adoption of a relatively narrow, eight-hour (noon to 8 p.m., Monday through Friday) time-of-use peak pricing period, with lower prices during the rest of the time would enable many, if not most, of the reference customers to limit their billing increases.

Q. ROGER COLTON, REPRESENTING CAPO/OECA, HAS RECOMMENDED THAT THE INITIAL 250 KWH BLOCK OF THE RESIDENTIAL RATE BE FROZEN AT 7.741 CENTS/KWH, WHILE STAFF HAS RECOMMENDED THAT IT BE INCREASED TO 8.218 CENTS. *(See Exhibit Staff/506/1.)* (PGE'S PROPOSAL, EMPLOYING THE SAME SCHEDULE REVENUE REQUIREMENT, WOULD PUT THE NEW LEVEL AT 8.443 CENTS. *See Exhibit PGE/2000/3.*) WHAT WOULD BE THE MAXIMUM SAVINGS A RESIDENTIAL CUSTOMER COULD EXPERIENCE FROM SUCH A CAPO/OECA-RECOMMENDED FREEZE?

A. A customer who used precisely 250 kWh's would save $1.19 per month.

Customers whose use exceeded that level would enjoy progressively lower savings owing to the fact that, for a given revenue requirement, freezing the first block rate would necessitate a higher-than-otherwise rate(s) for the next block(s).

Q. DOES STAFF SUPPORT THE CAPO/OECA RECOMMENDATION?

A. No, for two reasons. First, low use customers already receive a comparative benefit owing to the recommendation by both Staff and PGE that the customer charge not be increased. Referring to Exhibit Staff/507/1&2, you'll notice that the smallest customers receive the smallest percentage billing increases under our recommendations. Second, Staff shares the concerns expressed by PGE that many low-income families reside in high-consumption, all-electric homes and they would be unduly penalized by the higher second-block rates that would, by necessity, follow from the frozen first-block rate. *(See PGE/2000, page 34, lines 6-12.)*

Q. DR. ALAN ROSENBERG, ON BEHALF OF ICNU, HAS RECOMMENDED THAT A WEIGHTED FIVE-COINCIDENT-PEAK (i.e., 5 CP) ALLOCATOR BE INCORPORATED IN THE ENERGY/PRODUCTION COST ALLOCATION OF PGE. THAT ALLOCATOR WOULD APPLY TO THE COMPANY'S EMBEDDED FIXED GENERATION COSTS. DOES STAFF CONCUR WITH THAT RECOMMENDATION, AND IF NOT, WHY NOT?

A. Staff does not concur. We agree with the reasons in opposition that are summarized by PGE. *(See PGE/2000, pages 16 and 17.)* Since PGE depends upon market purchases to meet loads most of the time, and since the practice here in Oregon is to allocate the revenue requirement targets on the basis of marginal costs, it is appropriate for PGE to have allocated its energy and production costs on the basis of prices in the energy market. They are the best manifestation of PGE's marginal *costs*.

In addition, Staff would argue that the ICNU approach is fundamentally flawed in that it keys off of *loads* rather than *costs*. On the margin, PGE will add *capacity* via the construction of its own facilities for one basic reason: To meet its *net* peak load demands (see below for an elaboration on "net") when the costs of purchases (short- or long-term) are or would be so high as to make them uneconomic. Expressed a slightly different way, the value of owning production capacity comes from the ability attending therewith to avoid high purchase costs. While we agree that the Company must also plan its system such that it is assured of meeting firm loads, as noted above there are other considerations in adding generation supply. As stated at length elsewhere in my testimony, our regional purchase prices are largely driven to their highest yearly levels by the cooling loads in the Southwest, not by the winter heating loads of the Northwest. Accordingly, from an opportunity-cost point of view summer loads are more burdensome than are winter loads. Nevertheless (and quoting PGE), with ICNU's weighted-5-CP approach "the winter months receiv[e] 96% of the weights and summer months only 4%" despite the fact that "the highest prices cited by ICNU [itself] occur in months other than in the winter." *(See PGE/2000, page 17, lines 7-11.)* If recent historic market prices coincident with the five peak hours had instead been used to weight the loads of those hours, the summer loads would have incurred a composite weight a lot closer to 50% than to ICNU's 4%.[3]

Exacerbated the summer opportunity-cost burden for PGE is the fact that some of PGE's existing "capacity resources only cover th[e] winter period." *(See ICNU/200, page 9.)* Accordingly, "[t]he weighted five coincident peaks used by ICNU do not necessarily reflect the periods during which PGE may need capacity the most." *(See PGE/2000, page 16.)* The point here is that it is not gross loads, per se, that drive capacity acquisition needs on the margin, but rather *net* loads, i.e., the difference between loads and already-acquired or otherwise planned-for resources. ICNU's weighted-5-CP approach was based upon gross loads. So, if the hundred largest *net* loads had been used as the allocator, the summer loads would have incurred a composite weight a lot closer to 50% than to ICNU's 4%.[4] To conclude, plausible weightings other than the share of the 100 highest load hours would lead to very different fixed production cost allocations compared to what ICNU created. On the other hand, the way PGE acquires capacity on the margin, including the purchase of seasonal, sixteen-hour blocks, with additional spot

[3] A simple, unweighted 5CP approach allocates costs to each Schedule in proportion to the Schedule's share of the cumulative loads for just the five hours which correspond to the single coincident-peak hours of each of the five selected months. The "On-Peak" figures shown in Staff/502 vastly understate the single-hour, on-peak prices because those figures are the averages for the sixteen hours over all the days of the months except Sundays and holidays. Also recent historic monthly coincident peak prices are a better indicator than forecasted figures regarding just how high purchase prices can be because the latter tends to provide averages for every given hour since the day and hour of the month's coincident peak is not forecasted.

[4] Net loads correlate well with "loss-of-load-probabilities" (i.e., LOLP, having to do with the probability that a utility's capacity is insufficient for meeting its load requirements at a particular time).

purchases and sales for "balancing" purposes, may militate against using any kind of a monthly coincident peak approach altogether.

Q. WHAT IS THE PRIMARY NUMERICAL REVENUE REQUIREMENT ALLOCATIONS OUTCOME FROM INCORPORATING ICNU'S SUGGESTED APPROACH?

A. Compared to the current method, which allocates all of energy and production costs on the basis of costs and loads that transpire throughout the year, the residential class would experience relatively higher rates under the ICNU approach, which places its largest emphasis upon peak winter loads, when residential consumption is at its highest level.

Q. DOES STAFF STAND BY ITS EARLIER RECOMMENDATION TO ADOPT PGE'S MARGINAL-COST-BASED ALLOCATION APPROACH WITH REGARD TO ENERGY AND PRODUCTION COSTS, BOTH FIXED AND VARIABLE?

A. Yes. We agree with PGE that neither "the ICNU testimony [n]or any other developments persuaded [us] that PGE should change its marginal cost of generation methodology." *(See PGE/2000, page 16, lines 17-19.)* In the spirit of accepting the notion that possibly some consideration should be given to allocating own fixed costs separately from market purchases, we would be happy to pursue that matter outside of this general rate case. Of particular interest in any discussion will be how to distinguish a context where owned resources continue to be secondary to market purchases versus a case where a utility accommodates most of its load and virtually all of its growth through its existing and newly acquired owned resources.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes it does. Thank you.

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1300

Surrebuttal Testimony

September 15, 2008

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Steve Storm. I am employed by the Public Utility Commission of Oregon as the Program Manager of the Economic & Policy Analysis Section in the Economic Research and Financial Analysis Division. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. ARE YOU THE SAME STEVE STORM WHO SPONSORED EXHIBITS STAFF/600 – STAFF/615?

A. Yes. My Witness Qualifications Statement is found in Staff/601.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony involves two areas: PGE's marginal cost studies used to develop the Company's proposed rate spread, and PGE's SNA decoupling proposal and other proposed mechanisms associated with revenue recovery.

Q. WHAT ARE YOUR SUMMARY RECOMMENDATIONS?

A. Regarding PGE's marginal cost studies, I recommend the Commission adopt PGE's cost studies filed in its direct testimony and used to develop rate spread. I further recommend the Commission direct PGE to hold workshops to study cost study issues as identified in Staff's and other parties' testimony.

Regarding PGE's proposed Sales Normalization Adjustment (SNA) decoupling mechanism, and PGE's proposed Lost Revenue Recovery (LRR) and the minimally documented PGE-proposed "load-based" decoupling mechanism, I recommend the Commission reject each of these three mechanisms. I continue to recommend the Commission authorize the implementation of an Energy Efficiency Revenue Recovery (EERR) mechanism, as described in Staff/600.[1]

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibits Staff/1301, consisting of five pages and Staff/1302, consisting of two pages.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

[1] *See* Staff/600, page 31 at 17 through page 33, line 3.

PGE'S MARGINAL COST STUDIES

Q. WHAT IS YOUR GENERAL VIEW OF MARGINAL COSTS STUDIES, AS DEVELOPED FOR USE IN RATE SPREAD OF REVENUE REQUIREMENTS?

A. In Order No. 98-374, the Commission established a sound approach to consider marginal cost of electricity issues. A relevant excerpt of that order is:[2]

> "We will not require a single marginal cost approach for all utilities. Calculating marginal costs is as much of an art as it is a science. Allowing utilities to address the issue of calculating marginal costs in different ways has led to significant and productive new approaches to efficient pricing and costing of electrical service. We do not believe that mandating a single approach will advance the art of marginal cost analysis, and it could significantly impede progress.
>
> Furthermore, utilities should be allowed to choose approaches that best fit the particular circumstances of their systems and nature of their customers. We do not believe that we are capable of identifying a single approach that will satisfy the needs of every utility and its respective customers."

[2] As quoted in PGE/2000, page 10 at 17ff.

Q. WHAT WERE THE RECOMMENDATIONS IN YOUR DIRECT TESTIMONY REGARDING PGE'S MARGINAL COST STUDIES?

A. My cardinal recommendation was that the Commission accept PGE's marginal costs studies, as I found the results to be reasonable. I recommended the Commission direct PGE to emulate Pacific Power's general approach to customer cost allocations in PGE's next general rate case, specifying a minimum requirement to analyze and document the extent to which customers in the nonresidential rate schedules either impose a burden or receive a benefit greater than (or less than) that imposed upon or received by the average residential customer.[3] Additionally, I recommended the Commission direct PGE to hold workshops for the purpose of considering whether to revise the Company's basis for developing marginal cost estimates.[4]

Q. DO YOU CONTINUE TO SUPPORT THESE RECOMMENDATIONS?

A. Yes, including the recommendation that the Commission adopt PGE's marginal cost studies as presented in the Company's direct testimony. However, I also support the notion, embedded in the Commission's decision in Order No. 98-374 as quoted above, that it is important to "advance the art of marginal cost analysis," most especially when the results of such studies are used for rate spread purposes, with the resulting implications for horizontal equity.

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[3] *See* Staff/600 page 6, including footnote 6.

[4] *See* Staff/600, page 6 at 16.

Additionally, the near future—and prior to PGE's filing of the Company's next general rate case—seems an opportune time to re-examine the use of future market electricity prices for the allocation of generation revenue requirements, especially those pertaining to PGE facilities (*See* also Staff/500, page 9ff.), as PGE "anticipates frequent rate filings…"[5]

Q. HOW DID PGE RESPOND TO YOUR RECOMMENDATIONS?

A. PGE provided an extended response on the issue of allocating customer costs.[6] Regarding the issue of differentially-weighting operating characteristics such as the number of customers by rate schedule for use in allocating meter reading costs, PGE's position seems to be that results acceptable in prior dockets are *de facto* confirmation of the continuing appropriateness of methodology:

> "As with both UE 115 and UE 180, the meter reading marginal cost estimates in this proceeding reflect the results of this process, a process that yielded the same results in all three dockets. In the two prior dockets, Staff had no issue with the results."[7]

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[5] PGE/2000, page 19 at 1. By "frequent," PGE presumably means at intervals similar to the Company's very recent past; i.e., every two years or so.

[6] *See* PGE/2000, pages 7-10.

[7] PGE/2000, page 7 at 21.

This does not, if taken at face value, appear to be supportive of the notion of advancing the art of marginal cost analysis. If the methodology is never questioned,[8] is advancement likely or even possible?

PGE asserts that the Company's use of greater accounting detail in marginal cost analysis of "Other Consumer Service" costs provides more robust results than does the "Staff methodology."[9] This may be valid and Staff acknowledges the relevance of increased accounting granularity in providing potentially more robust analytical results, all else being equal.[10] PGE's reasoning that, since the Company's ratio of Other Consumer Service marginal costs between industrial customers and residential customers is higher than PacifiCorp's (27.3 versus 19.0), PGE's methodology is therefore more robust[11] is suspect at best. While "end results" may be indicative of a need for further investigation, they are—as "standalone" data—in no way conclusive, or indeed demonstrative, of a methodology which provides more robust results.

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8 In particular, the examination of marginal cost analysis methodologies by interested parties would appear to be particularly fruitful, in that there is presumably less investment in the *status quo*.

9 PGE/2000, page 9 at 13.

10 In some cost accounting "ideal world," each <u>customer</u> might have costs for various cost categories individually captured for a given time period. While this situation probably exists for industries where outputs are "one off" (or nearly so), such as large facility construction or the manufacture of commerical passenger aircraft, it almost certainly comes at a cost currently too high for use associated with the provisioning of retail electrical services.

11 PGE/2000, page 9 at 10.

Q. PGE EXPRESSED A WILLINGNESS "TO MEET WITH INTERESTED PARTIES TO DISCUSS MARGINAL COST ISSUES." WHAT ARE YOUR THOUGHTS?

A. Staff appreciates the offer. One possible reason marginal cost analyses have become more relevant is associated with the prospect of retail electricity price increases outstripping general inflation by a considerable margin going forward, even without an overlay of any future charges associated with carbon emissions. Price increases greatly exceeding overall price inflation place even greater importance on the appropriateness of measures used to allocate functional revenue requirements among multiple rate schedules. Therefore it is important that methodologies for allocating rapidly increasing revenue requirements be continually examined.

Q. PLEASE COMMENT ON THE MARGINAL COST OF GENERATION ISSUE.

A. This issue was mentioned in Staff's direct testimony[12] and extended testimony was presented by ICNU.[13] For Staff's primary surrebuttal testimony on this issue, please see Staff/1200, page 9ff. Staff acknowledges PGE's efforts in developing a "third option" for Commission consideration. An additional comment I might offer concerns certain implications of PGE's rebuttal testimony regarding this issue. PGE finds fault with ICNU's proposed five coincident peak

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[12] *See* Staff/600, page 5ff.

[13] ICNU/200, pages 1-12.

(5 CP) weighting methodology for allocation of PGE's generation revenue requirement:

> "This weighting is problematic because it narrowly focuses on PGE peak loads only and ignores regional peak loads. In other words, it is possible that PGE may need capacity during more of the summer hours than the winter hours due to regional peak load consumption."[14]

The results of marginal cost studies are used in this proceeding for allocating revenue requirements by functional category to various rate schedules. A principle being acknowledged in this process is that electric rates should be reflective of underlying costs. PGE testimony states: "We based the proposed rate schedules, as much as possible, on cost causation."[15] Additionally, the cost-of-service energy charge for each rate schedule is, according to PGE, "based on that schedule's allocated production cost. This allocated cost is comprised of the costs associated with PGE-owned generation, contract purchases of energy, transmission and capacity, and market purchases and sales."[16]

To the extent that the "it is possible" in PGE's testimony on this point, as quoted above, is factually (or statistically) "it is probable," the Company's testimony is congruent with Staff's thinking on this issue and is also highly

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[14] PGE/2000, page 17 at 4.

[15] PGE/1200, page 4 at 13.

[16] PGE/1200, page 5 at 6. Presumably PGE means contract purchases of not only energy, but also of transmission and capacity; i.e., "commas" were used in PGE's testimony where the use of "semicolons" would have left for this reader no ambiguity as to meaning.

supportive of the reasoning behind Staff's proposed introduction of seasonal energy rates, *with rates being higher in the summer*.[17]

PGE's PROPOSED DECOUPLING AND REVENUE RECOVERY MECHANISMS

Q. WHAT WERE OTHER PARTIES' RESPONSES TO PGE'S SALES NORMALIZATION ADJUSTMENT (SNA) DECOUPLING PROPOSAL?

A. Table 1 (below) summarizes the different parties' objections to PGE's proposed SNA mechanism, with the check mark signifying a party's objection.[18]

Table 1

Objection	CAPO-OECA	CUB	Fred Meyer	Staff
Transfers risk from PGE to customers		√	√	√
PGE's risk reduced without reduction in allowed return on equity			√	
Insulates PGE from effects of price elasticity/ "locks-in" PGE inefficiencies		√	√	
Not needed with frequent general rate cases		√		√
PGE likely to over-collect fixed cost revenue requirement due to customer growth				√
Adverse effects on low-income customers	√			
Shift of costs and risks associated with recession from PGE to customers		√		√
Energy efficiency programs moved from utilities to Energy Trust of Oregon		√	√	√
Shifts burden of regulatory lag from PGE to customers				√
Questionable efficacy of PGE objective to maintain price signals supportive of energy conservation				√
SNA charge/credit applied to direct access as well as cost-of-service customers			√	

17 *See* Staff/1200, pages 3 at 10ff.

18 Staff is cognizant of the potential for inadvertently either omitting or misconstruing other parties' testimony on this issue.

Q. DO YOU HAVE ANY COMMENTS ON PGE'S RESPONSES TO PARTIES' OBJECTIONS?

A. PGE's rebuttal testimony contains several responses on which I would like to comment. First, PGE witness Mr. Jim Piro asserts "(d)ecoupling allows the benefits of simultaneously providing customers with a price signal more closely aligned with marginal costs while allowing recovery of fixed costs through fixed charges."[19]

Staff believes neither side of what PGE is claiming decoupling provides is necessarily valid. On the "back" side, if fixed costs were actually being recovered through fixed charges, PGE's issue would largely disappear.[20] PGE's direct testimony implied that: a) revenues from fixed charges do not fully recover fixed costs; b) revenues from variable (volumetric) charges recover more than variable costs and contribute to the coverage of fixed costs; and c) if energy usage declines,[21] the amount of revenue from variable charges available to cover fixed costs is reduced, resulting in a situation in which PGE shareholders are harmed.[22,23] As pointed out in Staff's direct testimony, and

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[19] PGE/1300, page 37 at 7.

[20] If revenues from fixed charges exactly covered fixed costs, revenues from variable charges would therefore exactly cover variable charges. If usage is reduced, the reduction in variable revenues would be offset by the reduction in variable expenses. Therefore no inequities to shareholders would exist. Note that Staff is not at this time proposing PGE rates be restructured to achieve such an outcome.

[21] Actually, declines from the forecast usage levels incorporated in developing PGE's revenue requirement in a general rate case. More on this point later.

[22] *See* PGE/100, page 18, lines 5-7 and line 20 through page 19, line 1. *See* also Staff/600, page 14 at 6 and PGE/2100, page 5 at 13 through page 6 at 4.

[23] In this, PGE is (partially) correct: the issue is one of rate design. However, the issue is also one of regulatory lag.

assuming actual outcomes are reasonably close to the test-year predictions, this “harm” can only exist “in the “out” years between (the test years of) general rate cases.”[24]

On the “front” side, it is unclear what is being compared with a price signal “more closely aligned” with marginal costs. If PGE’s implied comparative reference here is to marginal variable costs, Staff is confident that higher fixed charges would also provide a price signal more closely aligned with marginal fixed costs; i.e., marginal costs are higher than embedded costs generally.

Q. PGE PROVIDED TESTIMONY REGARDING THE COMPANY’S DECOUPLING PROPOSAL IN PGE/2100. DO YOU HAVE ANY COMMENTS ON THAT TESTIMONY?

A. Yes. Several of PGE witness Mr. Ralph Cavanagh’s conclusions are presumably based on his interpretations of the demographic dynamics of PGE’s service territory and how those dynamics relate to energy usage. In disputing Staff’s hypothetical example of PGE’s over-collection of revenue in a recession,[25] he claims “recessions would be likely to affect customer growth along with usage per customer…”[26] Perhaps, especially if by “affect customer

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[24] *See* Staff’s discussion of this point at Staff/600 page 22 at 5.

[25] *See* Staff/600, page 20 line 18 through page 21 line 19; especially page 21, lines 12-15: “…a recessionary impact on usage per customer in an environment where customer growth continues could result in PGE’s revenues increasing under the SNA proposal whereas, absent the proposal, revenues would decline.” This is true for any causality negatively impacting usage per customer except weather.

[26] PGE/2100, page 16 at 9.

growth" Mr. Cavanagh means "less customer growth than what it might be realized in the absence of recession, but still *growth* in customers."

The National Bureau of Economic Research (NBER) provides national "peak" and "trough" dates (month/year) for U.S. business cycles, with the intervening timeframe defining a recession in the U.S. economy. Since 1985, the NBER has dated recessions beginning in July, 1990, and lasting eight months; and in March, 2001, and also lasting eight months.[27] PGE-provided data for both 1990 and 1991 and for 2001 reveal the following dynamics: PGE had annual residential customer growth rates of, respectively, +3.1%, +3.0%, and +1.0%. In the same years, respectively, PGE residential usage per customer on a weather-normalized basis grew at the following rates: -0.1%, -0.2%, and -4.7%.[28] Staff acknowledges that national recessions can have different timings and impacts on any individual state or region thereof, but clearly here are: a) three years in at least part of which the U.S. economy was in recession, b) three years in which PGE experienced growth in the number of residential customers, and c) three years in which PGE's residential usage per customer declined. Admittedly, the declines for 1990 and 1991 were of a smaller percentage than that used in Staff's example. Staff also acknowledges the events of 2000 – 2001 were extraordinary in several ways. Still, here are three

[27] *See* the NBER's "Business Cycle Expansion and Contractions" at http://www.nber.org/cycles.html .

[28] *See* Staff/1301, including a chart, a table, and PGE's response to Staff Data Request No. 443. PGE provided weather-normalized usage data. Note that residential outdoor lighting energy usage (a portion of rate schedule 15 usage) accounts for 0.1% of residential energy usage per PGE.

recessionary years, three years with positive PGE residential customer growth, and three years of negative growth in PGE usage per residential customer. In fact, examination of PGE-provided data reveals this is not at all unusual. In the 22 years for which PGE provided data (1986 – 2007), the following occurred: a) the number of PGE residential customers never declined year-over-year (not once!); b) total PGE residential usage had four years of year-over-year decline—all since 2000 (2000, 2001, 2002, and 2005); and c) PGE usage per residential customer experienced year-over-year declines in 15 years. In other words, Mr. Cavanagh's "implausible in the extreme"[29] (mis)characterization of Staff's hypothetical situation—positive PGE residential customer growth with simultaneous decline in PGE residential usage per customer—is arguably the norm; it has occurred 15 years in the last 22.

The facts cited in the immediately preceding are viewed by Staff as exceptionally strong support for the likelihood of scenarios and outcomes under PGE's SNA decoupling proposal in which the SNA adjustment positively applies, with a customer charge (not a credit) resulting from a decline in weather-normalized residential usage per customer while simultaneously the number of PGE's residential customers increases. This is precisely the over-collection scenario discussed at length in Staff/600 (*see* Staff/600, pages 17 – 21). And, based on PGE's history over the last 22 years, this scenario occurs with relatively high frequency; i.e., in 15 of the past 22 years between 1986 and 2007, inclusive.

[29] PGE/2100, page 16 at 3.

Staff developed Staff Example C (*see* Staff/1302, page 1) to assess the impact of PGE's SNA decoupling proposal over the next 22 years,[30] assuming PGE residential customer growth rates and the growth rate in usage per residential customer replicated PGE's experience of the last 22 years (1986 – 2007). Staff Example C shares many of the methodological techniques with Staff Examples A and B[31] and also with PGE/1208, page 2.[32]

After an initial nine-year period of mostly customer credits (2009 – 2017; based on PGE's 1986 – 1994 experience), the SNA provides for customer charges from that point forward. After this initial period, from 2018 through 2031, the SNA results in customer charges (not credits). By 2024 the Sales Normalization Adjustment mechanism provides adjustments maximized at the two percent of revenue constraint, thereby increasing the deferred SNA balance. The cumulative deferred SNA balance increases following 2024 until, at the period's end in 2031, it exceeds $256 million, which is approximately 25 percent of overall projected residential revenue. This balance would require over 12 years to reduce to $0 through the SNA mechanism—assuming no new additions to the balance over this 12 year period.[33] While this is a hypothetical

[30] The timeframe (22 years) used is due to that being the timeframe for which PGE provided data.

[31] Staff/607 and Staff/608, respectively.

[32] Key assumptions include <u>no</u> rate increases (or decreases) over the period other than that attributable to the SNA; the same "starting place" for the number of residential customers and for usage per customer as was used in PGE/1208, page 2; and, as mentioned above, the same year-by-year growth rates in the number of residential customers and their usage per customer. In other words, for these last two items, the rates for 1986 were used for 2010, 1987 for 2011, *et cetera*.

[33] This calculation assumes no growth (or decline) in revenues—consistent with the assumption of no rate cases and no rate increases (or declines). The calculation is: $256,010,283; divided

example, it's questionable whether a balance this large in the "real world" could be reduced to zero through the proposed SNA mechanism's workings—even in perhaps several human generations. Yes, decoupling adjustments "go both ways" as PGE witness Mr. Cavanagh points out,[34] except using PGE's own recent history, it goes against ratepayers 15 of 22 years.[35]

Q. FOLLOWING A DIMINISHING MARGINAL RATE OF RETURN ON ENERGY EFFICIENCY INVESTMENTS LINE OF REASONING, ARE PGE'S EXPERIENCES IN THE 1980S AND EARLY 1990S RELEVANT TO A DECISION ON THE COMPANY'S CURRENT SNA PROPOSAL?

A. Perhaps not. It's been almost 30 years since the Harvard Business School report pointed to conservation as the most cost-effective means of meeting energy demands,[36] and much has changed.[37] Staff revised the analysis described above to reflect the most recent 10 years of PGE experience (the experience acquired from 1998 through 2007, inclusive) (*see* Staff Example D in Staff/1302, page 2); i.e., addressing the question of what results under the proposed SNA mechanism might be should the next decade essentially mirror

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by the positive 2% SNA increase limitation on the $1,008,339,813 of 2031 revenue, or $20,166,796; equals 12.7 years.

[34] PGE/2100, page 16 at 14.

[35] The SNA with +2% Constraint is positive (a customer charge) in 15 of the 22 years after 2009 in Staff Example C.

[36] *See* ENERGY FUTURE REPORT OF THE ENERGY PROJECT AT THE HARVARD BUSINESS SCHOOL; edited by Robert Stobaugh and Daniel Yergin; New York: Random House 1979.

[37] Staff is not here making any claim as to the cost-effectiveness of any specific energy conservation programs.

the last decade in terms of the dynamics of the demographic environment in which PGE operates. This period included four years in which total PGE residential usage declined and seven years in which usage per customer declined. In other words, a "mixed bag" in terms of both changes in total residential usage and changes in average usage per customer. The results, however, were much the same as those in Staff Example C, which used the extended, 22 year period. The proposed SNA decoupling mechanism, as simulated in Staff Example D, provided customer charges (not credits) in each year (10 years out of 10). By the tenth year (2019), the cumulative deferred SNA totals almost $145 million, representing roughly 18% of the overall projected residential revenue. This balance would require nine years to reduce to $0 through the SNA mechanism—assuming no new additions to the balance over this nine year period.

Q. YOU HAVE PROVIDED TWO HYPOTHETICAL EXAMPLES OF THE WAY PGE'S PROPOSED SNA MECHANISM MIGHT WORK, ADMITTEDLY USING PGE'S OWN EXPERIENCE. IS THIS A "REAL WORLD" CONCERN?

A. Yes. Below is a selection taken from the "Maine Public Utilities Commission Report on Utility Incentives Mechanisms for the Promotion of Energy Efficiency and System Reliability," where CMP refers to Central Maine Power.

> "Maine has experience with revenue decoupling. In 1991, the Commission adopted, on a three-year trial basis, a revenue decoupling

mechanism for CMP (referred to as “Electric Revenue Adjustment Mechanism” or “ERAM”). The “allowed” revenue was determined in a rate case proceeding and adjusted annually based on changes in the utility’s number of customers. Analyses before the Commission at the time indicated that changes in the number of customers were at least as good an indicator of CMP's costs as changes in sales levels. CMP’s ERAM was not, however, a multi-year plan, so CMP was free to file a rate case at any time to adjust its “allowed” revenues.

CMP’s ERAM quickly became controversial. Around the time of its adoption, Maine, as well as the rest of New England, was at the start of a serious recession that resulted in lower sales levels. The lower sales levels caused substantial revenue deferrals that CMP was ultimately entitled to recover. CMP filed a rate case in October of 1991 that would have increased rates at the time, but likely would have caused lower amounts of revenue deferrals. However, the rate case was withdrawn by agreement of the parties to avoid immediate rate increases during bad economic times.

By the end of 1992, CMP’s ERAM deferral had reached $52 million. The consensus was that only a very small portion of this amount was due to CMP’s conservation efforts and that the vast majority of the deferral resulted from the economic recession. Thus, ERAM was increasingly viewed as a mechanism that was shielding CMP against the economic impact of the recession, rather than providing the intended energy efficiency and conservation incentive impact. The situation was exacerbated by a change in the financial accounting rules that limited the amount of time that utilities could carry deferrals on their books.

Maine's experiment with revenue cap regulation came to an end on November 30, 1993 when ERAM was terminated by stipulation of the parties."[38]

Please note that Staff is not claiming PGE's proposed SNA mechanism is the same as CMP's ERAM. Nor is Staff claiming that Oregon is Maine, or that the current period is the same as the early 1990s. The point is that automatic deferrals can work out in ways other than intended.

Q. ANY OTHER THOUGHTS ASSOCIATED WITH MR. CAVANAGH'S TESTIMONY IN PGE/2100?

A. Yes. I believe an important point regarding general rate cases, timing, and inequity to shareholders is in danger of getting overlooked. Mr. Cavanagh describes certain aspects of a general rate case proceeding (see PGE/2100, page 5 at line 17 through page 6, line 4) and asserts "…whether consumption ends up above or below regulators' expectation, every reduction in sales from efficiency improvements yields a corresponding reduction in cost recovery, to the detriment of shareholders." This is factually incorrect; from a rate case perspective, it is every reduction in sales from efficiency improvements *that*

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38 Footnotes omitted. *See* the report at http://www.mtpc.org/rebates/public_policy/dg/resources/2004-02-01_ME-PUC_Eff-RelReport.pdf .

have not been incorporated into the consumption (or sales) forecast that yields a corresponding reduction in cost recovery, potentially to the detriment of shareholders. PGE's load forecast in this proceeding explicitly incorporates reductions due to energy efficiency measures.[39] Where PGE shareholders may suffer is if PGE should over-forecast volumes, whether any shortfall from forecast is due to energy efficiency measures incremental to the incremental measures already explicitly incorporated within the forecast of volumes or some other causality. On this point, Staff is not aware of any party in the current proceeding recommending the Commission decrement PGE's load forecast; i.e., at this point, it is PGE's forecast.

Information included in PGE's rebuttal testimony allows a (Company-provided) light to shine on this issue: "PGE anticipates filing frequent rate cases."[40] The more frequent the filing, presumably the lower the potential that a test year's load forecast could be "wrong." If PGE will be filing frequent rate cases, many arguments for a decoupling proposal are substantially reduced. Notably, Mr. Cavanagh's recommendation that approval of the SNA "should be conditioned on PGE's agreement to file a new rate case within five years," while important, does not seem to be much of a requirement if PGE is "filing frequent rate cases."

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[39] *See* PGE/1100, page 8, lines 2 through 22.

[40] *See* PGE/2000, page 19 at 1.

Q. THIS PROCEEDING DEALS WITH THE TEST YEAR 2009 AND THE LOAD FORECASTS FOR THAT YEAR. INCREMENTAL ENERGY EFFIENCY MEASURES IN FOLLOW-ON YEARS SURELY HAVE AN IMPACT, DO THEY NOT?

A. Yes, they do, if they are incremental to the test year forecast. As this risk is currently borne by shareholders, and PGE's proposed SNA decoupling proposal removes this risk,[41] this shift of risk to the ratepayer[42] underlies Staff's concern about the shift of the burden of regulatory lag from shareholders to ratepayers without any compensatory reduction in PGE's rates. As stated in Staff's direct testimony, this risk has historically been borne by PGE shareholders, with recourse in the form of a general rate case, rather than by ratepayers.[43] And PGE anticipates "filing frequent rate cases."[44]

Mr. Cavanagh's claim that "decoupling adjustments go both ways,"[45] would seem, based on PGE-provided data, to mostly go against ratepayers. Fifteen of 22 years.

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[41] As well as removing the risk of the reduction in revenue resulting from any reduction in usage per customer for rate schedules 7 and 32/532 *for any reason except weather*. Note that PGE still retains the risk of weather-related reductions in usage per customer for these rate schedules. *See* PGE/100, page 23 at 12.

[42] "To the ratepayer" as it is ratepayers who will pay the SNA charge.

[43] See Staff/600, pages 26 through 27.

[44] PGE/2000, page 19 at 1.

[45] PGE/2100, page 16 at 14.

Q. THERE HAS BEEN TESTIMONY PROVIDED ON "EQUITY" BETWEEN RATEPAYER AND SHAREHOLDER IN THIS PROCEEDING. DO YOU HAVE ANY ADDITIONAL THOUGHTS ON EQUITY IN THIS REGARD?

A. Yes. Consider the following hypothetical situation. Suppose every residential PGE customer (ratepayer) who would be subject to PGE's proposed SNA decoupling mechanism reduces usage by five percent for 2010 over and above any amounts included in PGE's 2009 test year load forecast. Consider this reduction is on a weather-normalized basis. Let's also assume there is no growth in customers; indeed, every 2009 customer is a 2010 customer. Each customer's reduction can be for any reason at all: they are reacting to an electricity volumetric price signal, their personal circumstances have changed, they want to "do the right thing," they have incorporated energy efficiency measures, *et cetera*.

Now, what happens to their bills? First, their bills go down vis-à-vis what they otherwise would have been. Let's say their bills go down for each of 12 months and that in total their bills decline by five percent.[46] They've done "something:" they have changed their behaviors, they have invested in energy efficiency measures, "something."[47] They presumably not only feel like they

[46] This five percent decline in billed amounts is a simplification. Due to the presence of fixed charges and inverted block energy rates in Rate Schedule 7, the actual decline from a five percent decline in energy usage would likely be less than five percent. Symmetrically, the SNA charge also would likely be less than five percent. The key point is that bill reduction $s = SNA charge $s.

[47] This "something" is assumed by Staff to have a positive economic "cost" for each residential customer, whether it be financial outlays, opportunity costs, search costs, information costs, reduction in psychic income, other disutility, *et cetera*.

have saved money, they can see that this is so by viewing their monthly PGE bills.

All else being equal, PGE shareholders would bear the burden of these savings as manifested in reduced PGE earnings versus what would otherwise be the case. While the Company could potentially mitigate this outcome by reducing costs, shareholders have traditionally borne this type of burden and it is one for which they have been and are currently compensated.

How would this change under PGE's proposed SNA mechanism? PGE's Sales Normalization Adjustment would begin billing essentially for the reductions in customers' bills. In fact, under the provided assumptions, every customer would pay back every dollar of savings each initially realized, no matter what it was each customer did or did not do that created the energy savings and bill reductions.[48] Abstracting from any issues due to the time shifting of cash flows, PGE shareholders are "made whole." PGE residential customers are "made less."[49] This outcome captures the redistribution of equity between ratepayer and shareholder inherent in PGE's proposed SNA mechanism.

Additionally, Staff struggles to see how this arrangement is supportive of energy conservation, as viewed from the perspective of the individual ratepayer.[50] It is not clear to Staff that a Nash equilibrium[51] under PGE's

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48 This analysis abstracts from any own price elasticity considerations.

49 "Made less" in that they now consume less electricity for the same level of expenditure.

50 In a somewhat similar vein, see Staff/1200, page 1 at 15ff. for the discussion of cost-of-service versus direct access customers regarding a potential positive-feedback "death spiral."

proposed SNA decoupling mechanism is other than for residential customers to not perform any actions which result in energy conservation.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH PGE'S SNA DECOUPLING PROPOSAL?

A. Oregon has already undertaken perhaps the key action by forming the Energy Trust of Oregon. Below I include "bullet points" from a presentation given March 3, 2005, at the Harvard Electricity Policy Group's Thirty-Seventh Plenary Session by Maurice Brubaker of Brubaker & Associates, Inc. This presentation was in Session Two, concerning "Distribution Pricing: Do Revenue Caps Set Appropriate Incentives? Are they Fair to Consumers and Investors?"[52] On pages 11 through 15 of the presentation, Mr. Brubaker offers several salient points, including the following on page 15:

- Instead of decoupling revenue from sales
  - Decouple product sales from the promotion of conservation
- Allows everyone to do what they do best

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51 A nontechnical definition of Nash equilibrium is provided by Wikipedia at http://en.wikipedia.org/wiki/Nash_equilibrium . In particular: "Amy and Bill are in Nash equilibrium if Amy is making the best decision she can, taking into account Bill's decision, and Bill is making the best decision he can, taking into account Amy's decision. Likewise, many players are in Nash equilibrium if each one is making the best decision that they can, taking into account the decisions of the others. However, Nash equilibrium does not necessarily mean the best cumulative payoff for all the players involved; in many cases all the players might improve their payoffs if they could somehow agree on strategies different from the Nash equilibrium (e.g. competing businessmen forming a cartel in order to increase their profits)."

52 Mr. Brubaker's presentation can be found at: http://www.hks.harvard.edu/hepg/Papers/Brubaker.Session2.HEPG.0305.pdf .

This Oregon has done. Improvements can be made, but they do not include implementation of PGE's proposed SNA mechanism. I continue to recommend the Commission reject PGE's SNA decoupling proposal.

Q. PGE PROPOSED A LOST REVENUE RECOVERY (LRR) MECHANISM IN DIRECT TESTIMONY WHICH YOU RECOMMENDED BE REPLACED BY A MORE ENCOMPASSING, BUT SIMILAR MECHANISM. WHAT DID PGE PROVIDE IN REBUTTAL TESTIMONY REGARDING THESE MECHANISMS?

A. Staff is unaware of any parties other than PGE supporting the proposed LRR mechanism. In essence, for rate schedules other than 7 and 32/532, PGE proposed the LRR mechanism in direct testimony. Staff's direct testimony proposed, among other things, an Energy Efficiency Revenue Recovery (EERR) mechanism as an alternative to both PGE's proposed SNA and proposed LRR mechanisms. The EERR mechanism proposed by Staff would encompass the rate schedules PGE excluded from the LRR. Mr. Cavanagh's testimony in rebuttal recommends "the Commission select the second of the two approaches proposed by the Company (a "load-based" decoupling mechanism, as opposed to a "Lost Revenue Recovery" mechanism)."[53]

[53] PGE/2100, page 13 at 1.

Q. WHAT DO YOU THINK OF THE "LOAD-BASED" DECOUPLING PROPOSAL?

A. I believe this alternative, proposed for rate schedules other than 7 and 32/532, has many of the disadvantages of PGE's SNA proposal. In particular, it covers reduced load for causality other than energy efficiency measures.[54] Furthermore, it is not clear that the "load-based" decoupling mechanism would not cover variances from forecast due to weather. I recommend the Commission reject PGE's "load-based" decoupling mechanism.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

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[54] *See* PGE/100, page 22 at 1.

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1300

Surrebuttal Testimony

September 15, 2008

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Steve Storm. I am employed by the Public Utility Commission of Oregon as the Program Manager of the Economic & Policy Analysis Section in the Economic Research and Financial Analysis Division. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. ARE YOU THE SAME STEVE STORM WHO SPONSORED EXHIBITS STAFF/600 – STAFF/615?

A. Yes. My Witness Qualifications Statement is found in Staff/601.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony involves two areas: PGE's marginal cost studies used to develop the Company's proposed rate spread, and PGE's SNA decoupling proposal and other proposed mechanisms associated with revenue recovery.

Q. WHAT ARE YOUR SUMMARY RECOMMENDATIONS?

A. Regarding PGE's marginal cost studies, I recommend the Commission adopt PGE's cost studies filed in its direct testimony and used to develop rate spread. I further recommend the Commission direct PGE to hold workshops to study cost study issues as identified in Staff's and other parties' testimony.

Regarding PGE's proposed Sales Normalization Adjustment (SNA) decoupling mechanism, and PGE's proposed Lost Revenue Recovery (LRR) and the minimally documented PGE-proposed "load-based" decoupling mechanism, I recommend the Commission reject each of these three mechanisms. I continue to recommend the Commission authorize the implementation of an Energy Efficiency Revenue Recovery (EERR) mechanism, as described in Staff/600.[1]

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibits Staff/1301, consisting of five pages and Staff/1302, consisting of two pages.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

[1] *See* Staff/600, page 31 at 17 through page 33, line 3.

PGE'S MARGINAL COST STUDIES

Q. WHAT IS YOUR GENERAL VIEW OF MARGINAL COSTS STUDIES, AS DEVELOPED FOR USE IN RATE SPREAD OF REVENUE REQUIREMENTS?

A. In Order No. 98-374, the Commission established a sound approach to consider marginal cost of electricity issues. A relevant excerpt of that order is:[2]

> "We will not require a single marginal cost approach for all utilities. Calculating marginal costs is as much of an art as it is a science. Allowing utilities to address the issue of calculating marginal costs in different ways has led to significant and productive new approaches to efficient pricing and costing of electrical service. We do not believe that mandating a single approach will advance the art of marginal cost analysis, and it could significantly impede progress.
>
> Furthermore, utilities should be allowed to choose approaches that best fit the particular circumstances of their systems and nature of their customers. We do not believe that we are capable of identifying a single approach that will satisfy the needs of every utility and its respective customers."

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[2] As quoted in PGE/2000, page 10 at 17ff.

Q. WHAT WERE THE RECOMMENDATIONS IN YOUR DIRECT TESTIMONY REGARDING PGE'S MARGINAL COST STUDIES?

A. My cardinal recommendation was that the Commission accept PGE's marginal costs studies, as I found the results to be reasonable. I recommended the Commission direct PGE to emulate Pacific Power's general approach to customer cost allocations in PGE's next general rate case, specifying a minimum requirement to analyze and document the extent to which customers in the nonresidential rate schedules either impose a burden or receive a benefit greater than (or less than) that imposed upon or received by the average residential customer.[3] Additionally, I recommended the Commission direct PGE to hold workshops for the purpose of considering whether to revise the Company's basis for developing marginal cost estimates.[4]

Q. DO YOU CONTINUE TO SUPPORT THESE RECOMMENDATIONS?

A. Yes, including the recommendation that the Commission adopt PGE's marginal cost studies as presented in the Company's direct testimony. However, I also support the notion, embedded in the Commission's decision in Order No. 98-374 as quoted above, that it is important to "advance the art of marginal cost analysis," most especially when the results of such studies are used for rate spread purposes, with the resulting implications for horizontal equity.

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[3] *See* Staff/600 page 6, including footnote 6.

[4] *See* Staff/600, page 6 at 16.

Additionally, the near future—and prior to PGE's filing of the Company's next general rate case—seems an opportune time to re-examine the use of future market electricity prices for the allocation of generation revenue requirements, especially those pertaining to PGE facilities (*See* also Staff/500, page 9ff.), as PGE "anticipates frequent rate filings…"[5]

Q. HOW DID PGE RESPOND TO YOUR RECOMMENDATIONS?

A. PGE provided an extended response on the issue of allocating customer costs.[6] Regarding the issue of differentially-weighting operating characteristics such as the number of customers by rate schedule for use in allocating meter reading costs, PGE's position seems to be that results acceptable in prior dockets are *de facto* confirmation of the continuing appropriateness of methodology:

> "As with both UE 115 and UE 180, the meter reading marginal cost estimates in this proceeding reflect the results of this process, a process that yielded the same results in all three dockets. In the two prior dockets, Staff had no issue with the results."[7]

[5] PGE/2000, page 19 at 1. By "frequent," PGE presumably means at intervals similar to the Company's very recent past; i.e., every two years or so.

[6] *See* PGE/2000, pages 7-10.

[7] PGE/2000, page 7 at 21.

This does not, if taken at face value, appear to be supportive of the notion of advancing the art of marginal cost analysis. If the methodology is never questioned,[8] is advancement likely or even possible?

PGE asserts that the Company's use of greater accounting detail in marginal cost analysis of "Other Consumer Service" costs provides more robust results than does the "Staff methodology."[9] This may be valid and Staff acknowledges the relevance of increased accounting granularity in providing potentially more robust analytical results, all else being equal.[10] PGE's reasoning that, since the Company's ratio of Other Consumer Service marginal costs between industrial customers and residential customers is higher than PacifiCorp's (27.3 versus 19.0), PGE's methodology is therefore more robust[11] is suspect at best. While "end results" may be indicative of a need for further investigation, they are—as "standalone" data—in no way conclusive, or indeed demonstrative, of a methodology which provides more robust results.

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8 In particular, the examination of marginal cost analysis methodologies by interested parties would appear to be particularly fruitful, in that there is presumably less investment in the *status quo*.

9 PGE/2000, page 9 at 13.

10 In some cost accounting "ideal world," each <u>customer</u> might have costs for various cost categories individually captured for a given time period. While this situation probably exists for industries where outputs are "one off" (or nearly so), such as large facility construction or the manufacture of commerical passenger aircraft, it almost certainly comes at a cost currently too high for use associated with the provisioning of retail electrical services.

11 PGE/2000, page 9 at 10.

Q. PGE EXPRESSED A WILLINGNESS "TO MEET WITH INTERESTED PARTIES TO DISCUSS MARGINAL COST ISSUES." WHAT ARE YOUR THOUGHTS?

A. Staff appreciates the offer. One possible reason marginal cost analyses have become more relevant is associated with the prospect of retail electricity price increases outstripping general inflation by a considerable margin going forward, even without an overlay of any future charges associated with carbon emissions. Price increases greatly exceeding overall price inflation place even greater importance on the appropriateness of measures used to allocate functional revenue requirements among multiple rate schedules. Therefore it is important that methodologies for allocating rapidly increasing revenue requirements be continually examined.

Q. PLEASE COMMENT ON THE MARGINAL COST OF GENERATION ISSUE.

A. This issue was mentioned in Staff's direct testimony[12] and extended testimony was presented by ICNU.[13] For Staff's primary surrebuttal testimony on this issue, please see Staff/1200, page 9ff. Staff acknowledges PGE's efforts in developing a "third option" for Commission consideration. An additional comment I might offer concerns certain implications of PGE's rebuttal testimony regarding this issue. PGE finds fault with ICNU's proposed five coincident peak

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12 *See* Staff/600, page 5ff.

13 ICNU/200, pages 1-12.

(5 CP) weighting methodology for allocation of PGE's generation revenue requirement:

> "This weighting is problematic because it narrowly focuses on PGE peak loads only and ignores regional peak loads. In other words, it is possible that PGE may need capacity during more of the summer hours than the winter hours due to regional peak load consumption."[14]

The results of marginal cost studies are used in this proceeding for allocating revenue requirements by functional category to various rate schedules. A principle being acknowledged in this process is that electric rates should be reflective of underlying costs. PGE testimony states: "We based the proposed rate schedules, as much as possible, on cost causation."[15] Additionally, the cost-of-service energy charge for each rate schedule is, according to PGE, "based on that schedule's allocated production cost. This allocated cost is comprised of the costs associated with PGE-owned generation, contract purchases of energy, transmission and capacity, and market purchases and sales."[16]

To the extent that the "it is possible" in PGE's testimony on this point, as quoted above, is factually (or statistically) "it is probable," the Company's testimony is congruent with Staff's thinking on this issue and is also highly

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[14] PGE/2000, page 17 at 4.

[15] PGE/1200, page 4 at 13.

[16] PGE/1200, page 5 at 6. Presumably PGE means contract purchases of not only energy, but also of transmission and capacity; i.e., "commas" were used in PGE's testimony where the use of "semicolons" would have left for this reader no ambiguity as to meaning.

supportive of the reasoning behind Staff's proposed introduction of seasonal energy rates, *with rates being higher in the summer*.[17]

PGE's PROPOSED DECOUPLING AND REVENUE RECOVERY MECHANISMS

Q. WHAT WERE OTHER PARTIES' RESPONSES TO PGE'S SALES NORMALIZATION ADJUSTMENT (SNA) DECOUPLING PROPOSAL?

A. Table 1 (below) summarizes the different parties' objections to PGE's proposed SNA mechanism, with the check mark signifying a party's objection.[18]

Table 1

Objection	CAPO-OECA	CUB	Fred Meyer	Staff
Transfers risk from PGE to customers		√	√	√
PGE's risk reduced without reduction in allowed return on equity			√	
Insulates PGE from effects of price elasticity/ "locks-in" PGE inefficiencies		√	√	
Not needed with frequent general rate cases		√		√
PGE likely to over-collect fixed cost revenue requirement due to customer growth				√
Adverse effects on low-income customers	√			
Shift of costs and risks associated with recession from PGE to customers		√		√
Energy efficiency programs moved from utilities to Energy Trust of Oregon		√	√	√
Shifts burden of regulatory lag from PGE to customers				√
Questionable efficacy of PGE objective to maintain price signals supportive of energy conservation				√
SNA charge/credit applied to direct access as well as cost-of-service customers			√	

[17] *See* Staff/1200, pages 3 at 10ff.

[18] Staff is cognizant of the potential for inadvertently either omitting or misconstruing other parties' testimony on this issue.

Q. DO YOU HAVE ANY COMMENTS ON PGE'S RESPONSES TO PARTIES' OBJECTIONS?

A. PGE's rebuttal testimony contains several responses on which I would like to comment. First, PGE witness Mr. Jim Piro asserts "(d)ecoupling allows the benefits of simultaneously providing customers with a price signal more closely aligned with marginal costs while allowing recovery of fixed costs through fixed charges."[19]

Staff believes neither side of what PGE is claiming decoupling provides is necessarily valid. On the "back" side, if fixed costs were actually being recovered through fixed charges, PGE's issue would largely disappear.[20] PGE's direct testimony implied that: a) revenues from fixed charges do not fully recover fixed costs; b) revenues from variable (volumetric) charges recover more than variable costs and contribute to the coverage of fixed costs; and c) if energy usage declines,[21] the amount of revenue from variable charges available to cover fixed costs is reduced, resulting in a situation in which PGE shareholders are harmed.[22,23] As pointed out in Staff's direct testimony, and

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[19] PGE/1300, page 37 at 7.

[20] If revenues from fixed charges exactly covered fixed costs, revenues from variable charges would therefore exactly cover variable charges. If usage is reduced, the reduction in variable revenues would be offset by the reduction in variable expenses. Therefore no inequities to shareholders would exist. Note that Staff is not at this time proposing PGE rates be restructured to achieve such an outcome.

[21] Actually, declines from the forecast usage levels incorporated in developing PGE's revenue requirement in a general rate case. More on this point later.

[22] *See* PGE/100, page 18, lines 5-7 and line 20 through page 19, line 1. *See* also Staff/600, page 14 at 6 and PGE/2100, page 5 at 13 through page 6 at 4.

[23] In this, PGE is (partially) correct: the issue is one of rate design. However, the issue is also one of regulatory lag.

assuming actual outcomes are reasonably close to the test-year predictions, this "harm" can only exist "in the "out" years between (the test years of) general rate cases."[24]

On the "front" side, it is unclear what is being compared with a price signal "more closely aligned" with marginal costs. If PGE's implied comparative reference here is to marginal variable costs, Staff is confident that higher <u>fixed</u> charges would also provide a price signal more closely aligned with marginal fixed costs; i.e., marginal costs are higher than embedded costs generally.

Q. PGE PROVIDED TESTIMONY REGARDING THE COMPANY'S DECOUPLING PROPOSAL IN PGE/2100. DO YOU HAVE ANY COMMENTS ON THAT TESTIMONY?

A. Yes. Several of PGE witness Mr. Ralph Cavanagh's conclusions are presumably based on his interpretations of the demographic dynamics of PGE's service territory and how those dynamics relate to energy usage. In disputing Staff's hypothetical example of PGE's over-collection of revenue in a recession,[25] he claims "recessions would be likely to affect customer growth along with usage per customer…"[26] Perhaps, especially if by "affect customer

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[24] *See* Staff's discussion of this point at Staff/600 page 22 at 5.

[25] *See* Staff/600, page 20 line 18 through page 21 line 19; especially page 21, lines 12-15: "…a recessionary impact on usage per customer in an environment where customer growth continues could result in PGE's revenues increasing under the SNA proposal whereas, absent the proposal, revenues would decline." This is true for any causality negatively impacting usage per customer except weather.

[26] PGE/2100, page 16 at 9.

growth" Mr. Cavanagh means "less customer growth than what it might be realized in the absence of recession, but still *growth* in customers."

The National Bureau of Economic Research (NBER) provides national "peak" and "trough" dates (month/year) for U.S. business cycles, with the intervening timeframe defining a recession in the U.S. economy. Since 1985, the NBER has dated recessions beginning in July, 1990, and lasting eight months; and in March, 2001, and also lasting eight months.[27] PGE-provided data for both 1990 and 1991 and for 2001 reveal the following dynamics: PGE had annual residential customer growth rates of, respectively, +3.1%, +3.0%, and +1.0%. In the same years, respectively, PGE residential usage per customer on a weather-normalized basis grew at the following rates: -0.1%, -0.2%, and -4.7%.[28] Staff acknowledges that national recessions can have different timings and impacts on any individual state or region thereof, but clearly here are: a) three years in at least part of which the U.S. economy was in recession, b) three years in which PGE experienced growth in the number of residential customers, and c) three years in which PGE's residential usage per customer declined. Admittedly, the declines for 1990 and 1991 were of a smaller percentage than that used in Staff's example. Staff also acknowledges the events of 2000 – 2001 were extraordinary in several ways. Still, here are three

27 *See* the NBER's "Business Cycle Expansion and Contractions" at http://www.nber.org/cycles.html .

28 *See* Staff/1301, including a chart, a table, and PGE's response to Staff Data Request No. 443. PGE provided weather-normalized usage data. Note that residential outdoor lighting energy usage (a portion of rate schedule 15 usage) accounts for 0.1% of residential energy usage per PGE.

recessionary years, three years with positive PGE residential customer growth, and three years of negative growth in PGE usage per residential customer. In fact, examination of PGE-provided data reveals this is not at all unusual. In the 22 years for which PGE provided data (1986 – 2007), the following occurred: a) the number of PGE residential customers never declined year-over-year (not once!); b) total PGE residential usage had four years of year-over-year decline—all since 2000 (2000, 2001, 2002, and 2005); and c) PGE usage per residential customer experienced year-over-year declines in 15 years. In other words, Mr. Cavanagh's "implausible in the extreme"[29] (mis)characterization of Staff's hypothetical situation—positive PGE residential customer growth with simultaneous decline in PGE residential usage per customer—is arguably the norm; it has occurred 15 years in the last 22.

The facts cited in the immediately preceding are viewed by Staff as exceptionally strong support for the likelihood of scenarios and outcomes under PGE's SNA decoupling proposal in which the SNA adjustment positively applies, with a customer charge (not a credit) resulting from a decline in weather-normalized residential usage per customer while simultaneously the number of PGE's residential customers increases. This is precisely the over-collection scenario discussed at length in Staff/600 (*see* Staff/600, pages 17 – 21). And, based on PGE's history over the last 22 years, this scenario occurs with relatively high frequency; i.e., in 15 of the past 22 years between 1986 and 2007, inclusive.

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[29] PGE/2100, page 16 at 3.

Staff developed Staff Example C (*see* Staff/1302, page 1) to assess the impact of PGE's SNA decoupling proposal over the next 22 years,[30] assuming PGE residential customer growth rates and the growth rate in usage per residential customer replicated PGE's experience of the last 22 years (1986 – 2007). Staff Example C shares many of the methodological techniques with Staff Examples A and B[31] and also with PGE/1208, page 2.[32]

After an initial nine-year period of mostly customer credits (2009 – 2017; based on PGE's 1986 – 1994 experience), the SNA provides for customer charges from that point forward. After this initial period, from 2018 through 2031, the SNA results in customer charges (not credits). By 2024 the Sales Normalization Adjustment mechanism provides adjustments maximized at the two percent of revenue constraint, thereby increasing the deferred SNA balance. The cumulative deferred SNA balance increases following 2024 until, at the period's end in 2031, it exceeds $256 million, which is approximately 25 percent of overall projected residential revenue. This balance would require over 12 years to reduce to $0 through the SNA mechanism—assuming no new additions to the balance over this 12 year period.[33] While this is a hypothetical

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[30] The timeframe (22 years) used is due to that being the timeframe for which PGE provided data.

[31] Staff/607 and Staff/608, respectively.

[32] Key assumptions include <u>no</u> rate increases (or decreases) over the period other than that attributable to the SNA; the same "starting place" for the number of residential customers and for usage per customer as was used in PGE/1208, page 2; and, as mentioned above, the same year-by-year growth rates in the number of residential customers and their usage per customer. In other words, for these last two items, the rates for 1986 were used for 2010, 1987 for 2011, *et cetera*.

[33] This calculation assumes no growth (or decline) in revenues—consistent with the assumption of no rate cases and no rate increases (or declines). The calculation is: $256,010,283; divided

example, it's questionable whether a balance this large in the "real world" could be reduced to zero through the proposed SNA mechanism's workings—even in perhaps several human generations. Yes, decoupling adjustments "go both ways" as PGE witness Mr. Cavanagh points out,[34] except using PGE's own recent history, it goes against ratepayers 15 of 22 years.[35]

Q. FOLLOWING A DIMINISHING MARGINAL RATE OF RETURN ON ENERGY EFFICIENCY INVESTMENTS LINE OF REASONING, ARE PGE'S EXPERIENCES IN THE 1980S AND EARLY 1990S RELEVANT TO A DECISION ON THE COMPANY'S CURRENT SNA PROPOSAL?

A. Perhaps not. It's been almost 30 years since the Harvard Business School report pointed to conservation as the most cost-effective means of meeting energy demands,[36] and much has changed.[37] Staff revised the analysis described above to reflect the most recent 10 years of PGE experience (the experience acquired from 1998 through 2007, inclusive) (*see* Staff Example D in Staff/1302, page 2); i.e., addressing the question of what results under the proposed SNA mechanism might be should the next decade essentially mirror

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by the positive 2% SNA increase limitation on the $1,008,339,813 of 2031 revenue, or $20,166,796; equals 12.7 years.

[34] PGE/2100, page 16 at 14.

[35] The SNA with +2% Constraint is positive (a customer charge) in 15 of the 22 years after 2009 in Staff Example C.

[36] *See* ENERGY FUTURE REPORT OF THE ENERGY PROJECT AT THE HARVARD BUSINESS SCHOOL; edited by Robert Stobaugh and Daniel Yergin; New York: Random House 1979.

[37] Staff is not here making any claim as to the cost-effectiveness of any specific energy conservation programs.

the last decade in terms of the dynamics of the demographic environment in which PGE operates. This period included four years in which total PGE residential usage declined and seven years in which usage per customer declined. In other words, a “mixed bag” in terms of both changes in total residential usage and changes in average usage per customer. The results, however, were much the same as those in Staff Example C, which used the extended, 22 year period. The proposed SNA decoupling mechanism, as simulated in Staff Example D, provided customer charges (not credits) in each year (10 years out of 10). By the tenth year (2019), the cumulative deferred SNA totals almost $145 million, representing roughly 18% of the overall projected residential revenue. This balance would require nine years to reduce to $0 through the SNA mechanism—assuming no new additions to the balance over this nine year period.

Q. YOU HAVE PROVIDED TWO HYPOTHETICAL EXAMPLES OF THE WAY PGE’S PROPOSED SNA MECHANISM MIGHT WORK, ADMITTEDLY USING PGE’S OWN EXPERIENCE. IS THIS A “REAL WORLD” CONCERN?

A. Yes. Below is a selection taken from the “Maine Public Utilities Commission Report on Utility Incentives Mechanisms for the Promotion of Energy Efficiency and System Reliability,” where CMP refers to Central Maine Power.

> “Maine has experience with revenue decoupling. In 1991, the Commission adopted, on a three-year trial basis, a revenue decoupling

mechanism for CMP (referred to as “Electric Revenue Adjustment Mechanism” or “ERAM”). The “allowed” revenue was determined in a rate case proceeding and adjusted annually based on changes in the utility’s number of customers. Analyses before the Commission at the time indicated that changes in the number of customers were at least as good an indicator of CMP's costs as changes in sales levels. CMP’s ERAM was not, however, a multi-year plan, so CMP was free to file a rate case at any time to adjust its “allowed” revenues.

CMP’s ERAM quickly became controversial. Around the time of its adoption, Maine, as well as the rest of New England, was at the start of a serious recession that resulted in lower sales levels. The lower sales levels caused substantial revenue deferrals that CMP was ultimately entitled to recover. CMP filed a rate case in October of 1991 that would have increased rates at the time, but likely would have caused lower amounts of revenue deferrals. However, the rate case was withdrawn by agreement of the parties to avoid immediate rate increases during bad economic times.

By the end of 1992, CMP’s ERAM deferral had reached $52 million. The consensus was that only a very small portion of this amount was due to CMP’s conservation efforts and that the vast majority of the deferral resulted from the economic recession. Thus, ERAM was increasingly viewed as a mechanism that was shielding CMP against the economic impact of the recession, rather than providing the intended energy efficiency and conservation incentive impact. The situation was exacerbated by a change in the financial accounting rules that limited the amount of time that utilities could carry deferrals on their books.

Maine's experiment with revenue cap regulation came to an end on November 30, 1993 when ERAM was terminated by stipulation of the parties."[38]

Please note that Staff is not claiming PGE's proposed SNA mechanism is the same as CMP's ERAM. Nor is Staff claiming that Oregon is Maine, or that the current period is the same as the early 1990s. The point is that automatic deferrals can work out in ways other than intended.

Q. ANY OTHER THOUGHTS ASSOCIATED WITH MR. CAVANAGH'S TESTIMONY IN PGE/2100?

A. Yes. I believe an important point regarding general rate cases, timing, and inequity to shareholders is in danger of getting overlooked. Mr. Cavanagh describes certain aspects of a general rate case proceeding (see PGE/2100, page 5 at line 17 through page 6, line 4) and asserts "…whether consumption ends up above or below regulators' expectation, every reduction in sales from efficiency improvements yields a corresponding reduction in cost recovery, to the detriment of shareholders." This is factually incorrect; from a rate case perspective, it is every reduction in sales from efficiency improvements *that*

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[38] Footnotes omitted. *See* the report at http://www.mtpc.org/rebates/public_policy/dg/resources/2004-02-01_ME-PUC_Eff-RelReport.pdf .

have not been incorporated into the consumption (or sales) forecast that yields a corresponding reduction in cost recovery, potentially to the detriment of shareholders. PGE's load forecast in this proceeding explicitly incorporates reductions due to energy efficiency measures.[39] Where PGE shareholders may suffer is if PGE should over-forecast volumes, whether any shortfall from forecast is due to energy efficiency measures incremental to the incremental measures already explicitly incorporated within the forecast of volumes or some other causality. On this point, Staff is not aware of any party in the current proceeding recommending the Commission decrement PGE's load forecast; i.e., at this point, it is PGE's forecast.

Information included in PGE's rebuttal testimony allows a (Company-provided) light to shine on this issue: "PGE anticipates filing frequent rate cases."[40] The more frequent the filing, presumably the lower the potential that a test year's load forecast could be "wrong." If PGE will be filing frequent rate cases, many arguments for a decoupling proposal are substantially reduced. Notably, Mr. Cavanagh's recommendation that approval of the SNA "should be conditioned on PGE's agreement to file a new rate case within five years," while important, does not seem to be much of a requirement if PGE is "filing frequent rate cases."

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[39] *See* PGE/1100, page 8, lines 2 through 22.

[40] *See* PGE/2000, page 19 at 1.

Q. THIS PROCEEDING DEALS WITH THE TEST YEAR 2009 AND THE LOAD FORECASTS FOR THAT YEAR. INCREMENTAL ENERGY EFFIENCY MEASURES IN FOLLOW-ON YEARS SURELY HAVE AN IMPACT, DO THEY NOT?

A. Yes, they do, if they are incremental to the test year forecast. As this risk is currently borne by shareholders, and PGE's proposed SNA decoupling proposal removes this risk,[41] this shift of risk to the ratepayer[42] underlies Staff's concern about the shift of the burden of regulatory lag from shareholders to ratepayers without any compensatory reduction in PGE's rates. As stated in Staff's direct testimony, this risk has historically been borne by PGE shareholders, with recourse in the form of a general rate case, rather than by ratepayers.[43] And PGE anticipates "filing frequent rate cases."[44]

Mr. Cavanagh's claim that "decoupling adjustments go both ways,"[45] would seem, based on PGE-provided data, to mostly go against ratepayers. Fifteen of 22 years.

[41] As well as removing the risk of the reduction in revenue resulting from any reduction in usage per customer for rate schedules 7 and 32/532 *for any reason except weather*. Note that PGE still retains the risk of weather-related reductions in usage per customer for these rate schedules. *See* PGE/100, page 23 at 12.

[42] "To the ratepayer" as it is ratepayers who will pay the SNA charge.

[43] See Staff/600, pages 26 through 27.

[44] PGE/2000, page 19 at 1.

[45] PGE/2100, page 16 at 14.

Q. THERE HAS BEEN TESTIMONY PROVIDED ON "EQUITY" BETWEEN RATEPAYER AND SHAREHOLDER IN THIS PROCEEDING. DO YOU HAVE ANY ADDITIONAL THOUGHTS ON EQUITY IN THIS REGARD?

A. Yes. Consider the following hypothetical situation. Suppose every residential PGE customer (ratepayer) who would be subject to PGE's proposed SNA decoupling mechanism reduces usage by five percent for 2010 over and above any amounts included in PGE's 2009 test year load forecast. Consider this reduction is on a weather-normalized basis. Let's also assume there is no growth in customers; indeed, every 2009 customer is a 2010 customer. Each customer's reduction can be for any reason at all: they are reacting to an electricity volumetric price signal, their personal circumstances have changed, they want to "do the right thing," they have incorporated energy efficiency measures, *et cetera*.

Now, what happens to their bills? First, their bills go down vis-à-vis what they otherwise would have been. Let's say their bills go down for each of 12 months and that in total their bills decline by five percent.[46] They've done "something:" they have changed their behaviors, they have invested in energy efficiency measures, "something."[47] They presumably not only feel like they

46 This five percent decline in billed amounts is a simplification. Due to the presence of fixed charges and inverted block energy rates in Rate Schedule 7, the actual decline from a five percent decline in energy usage would likely be less than five percent. Symmetrically, the SNA charge also would likely be less than five percent. The key point is that bill reduction $s = SNA charge $s.

47 This "something" is assumed by Staff to have a positive economic "cost" for each residential customer, whether it be financial outlays, opportunity costs, search costs, information costs, reduction in psychic income, other disutility, *et cetera*.

have saved money, they can see that this is so by viewing their monthly PGE bills.

All else being equal, PGE shareholders would bear the burden of these savings as manifested in reduced PGE earnings versus what would otherwise be the case. While the Company could potentially mitigate this outcome by reducing costs, shareholders have traditionally borne this type of burden and it is one for which they have been and are currently compensated.

How would this change under PGE's proposed SNA mechanism? PGE's Sales Normalization Adjustment would begin billing essentially for the reductions in customers' bills. In fact, under the provided assumptions, every customer would pay back every dollar of savings each initially realized, no matter what it was each customer did or did not do that created the energy savings and bill reductions.[48] Abstracting from any issues due to the time shifting of cash flows, PGE shareholders are "made whole." PGE residential customers are "made less."[49] This outcome captures the redistribution of equity between ratepayer and shareholder inherent in PGE's proposed SNA mechanism.

Additionally, Staff struggles to see how this arrangement is supportive of energy conservation, as viewed from the perspective of the individual ratepayer.[50] It is not clear to Staff that a Nash equilibrium[51] under PGE's

[48] This analysis abstracts from any own price elasticity considerations.

[49] "Made less" in that they now consume less electricity for the same level of expenditure.

[50] In a somewhat similar vein, see Staff/1200, page 1 at 15ff. for the discussion of cost-of-service versus direct access customers regarding a potential positive-feedback "death spiral."

proposed SNA decoupling mechanism is other than for residential customers to not perform any actions which result in energy conservation.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH PGE'S SNA DECOUPLING PROPOSAL?

A. Oregon has already undertaken perhaps the key action by forming the Energy Trust of Oregon. Below I include "bullet points" from a presentation given March 3, 2005, at the Harvard Electricity Policy Group's Thirty-Seventh Plenary Session by Maurice Brubaker of Brubaker & Associates, Inc. This presentation was in Session Two, concerning "Distribution Pricing: Do Revenue Caps Set Appropriate Incentives? Are they Fair to Consumers and Investors?"[52] On pages 11 through 15 of the presentation, Mr. Brubaker offers several salient points, including the following on page 15:

- Instead of decoupling revenue from sales
    - o Decouple product sales from the promotion of conservation
- Allows everyone to do what they do best

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[51] A nontechnical definition of Nash equilibrium is provided by Wikipedia at http://en.wikipedia.org/wiki/Nash_equilibrium . In particular: "Amy and Bill are in Nash equilibrium if Amy is making the best decision she can, taking into account Bill's decision, and Bill is making the best decision he can, taking into account Amy's decision. Likewise, many players are in Nash equilibrium if each one is making the best decision that they can, taking into account the decisions of the others. However, Nash equilibrium does not necessarily mean the best cumulative payoff for all the players involved; in many cases all the players might improve their payoffs if they could somehow agree on strategies different from the Nash equilibrium (e.g. competing businessmen forming a cartel in order to increase their profits)."

[52] Mr. Brubaker's presentation can be found at: http://www.hks.harvard.edu/hepg/Papers/Brubaker.Session2.HEPG.0305.pdf .

This Oregon has done. Improvements can be made, but they do not include implementation of PGE's proposed SNA mechanism. I continue to recommend the Commission reject PGE's SNA decoupling proposal.

Q. PGE PROPOSED A LOST REVENUE RECOVERY (LRR) MECHANISM IN DIRECT TESTIMONY WHICH YOU RECOMMENDED BE REPLACED BY A MORE ENCOMPASSING, BUT SIMILAR MECHANISM. WHAT DID PGE PROVIDE IN REBUTTAL TESTIMONY REGARDING THESE MECHANISMS?

A. Staff is unaware of any parties other than PGE supporting the proposed LRR mechanism. In essence, for rate schedules other than 7 and 32/532, PGE proposed the LRR mechanism in direct testimony. Staff's direct testimony proposed, among other things, an Energy Efficiency Revenue Recovery (EERR) mechanism as an alternative to both PGE's proposed SNA and proposed LRR mechanisms. The EERR mechanism proposed by Staff would encompass the rate schedules PGE excluded from the LRR. Mr. Cavanagh's testimony in rebuttal recommends "the Commission select the second of the two approaches proposed by the Company (a "load-based" decoupling mechanism, as opposed to a "Lost Revenue Recovery" mechanism)."[53]

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[53] PGE/2100, page 13 at 1.

Q. WHAT DO YOU THINK OF THE "LOAD-BASED" DECOUPLING PROPOSAL?

A. I believe this alternative, proposed for rate schedules other than 7 and 32/532, has many of the disadvantages of PGE's SNA proposal. In particular, it covers reduced load for causality other than energy efficiency measures.[54] Furthermore, it is not clear that the "load-based" decoupling mechanism would <u>not</u> cover variances from forecast due to weather. I recommend the Commission reject PGE's "load-based" decoupling mechanism.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

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[54] *See* PGE/100, page 22 at 1.

CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1301

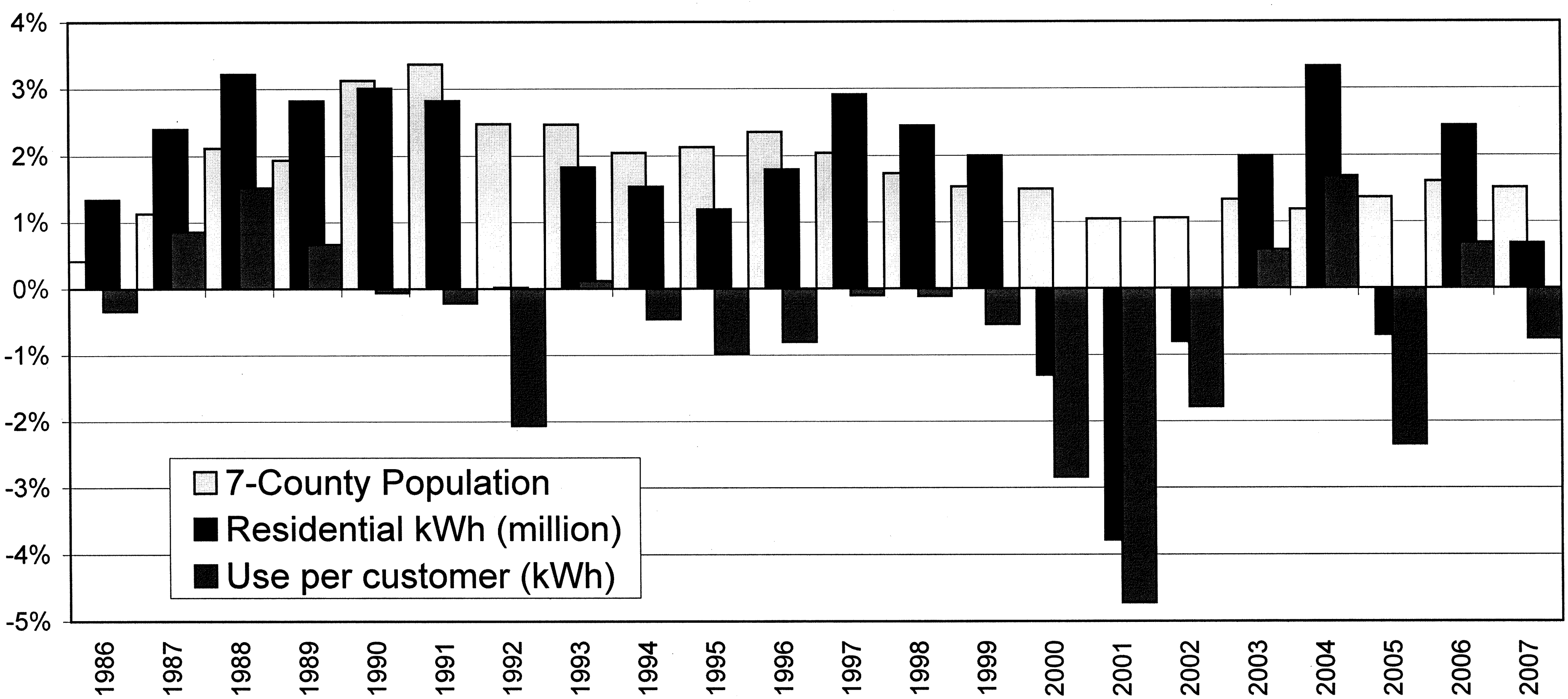
Exhibits in Support
of Surrebuttal Testimony

September 15, 2008

PGE Response to Staff Data Request 443(d)

Population and Residential Energy Use

Energy Use data is Weather-normalized



PGE Response to Staff Data Request No. 443(a)

Population and Residential Energy Use

Energy Use data is Weather-normalized

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
7-County Population [1]	1,429,750	1,435,700	1,451,900	1,482,600	1,511,300	1,558,500	1,610,910	1,650,780	1,691,510	1,726,050	1,762,760	1,804,190	1,841,000	1,872,840	1,901,470	1,929,850	1,950,050	1,970,700	1,996,950	2,020,650	2,048,245	2,081,145	2,112,595
% Change		0.4%	1.1%	2.1%	1.9%	3.1%	3.4%	2.5%	2.5%	2.0%	2.1%	2.4%	2.0%	1.7%	1.5%	1.5%	1.0%	1.1%	1.3%	1.2%	1.4%	1.6%	1.5%
Residential kWh (million) [2]	5,611	5,686	5,823	6,010	6,179	6,365	6,545	6,546	6,665	6,768	6,848	6,971	7,173	7,349	7,495	7,398	7,118	7,061	7,201	7,440	7,388	7,568	7,619
% Change		1.3%	2.4%	3.2%	2.8%	3.0%	2.8%	0.0%	1.8%	1.5%	1.2%	1.8%	2.9%	2.4%	2.0%	-1.3%	-3.8%	-0.8%	2.0%	3.3%	-0.7%	2.4%	0.7%
# of Residential Customers	457,119	464,802	471,891	479,787	490,039	505,086	520,449	531,536	540,591	551,420	563,514	578,254	595,683	610,952	626,539	636,449	642,708	649,145	658,232	668,830	680,093	691,931	701,952
% Change		1.7%	1.5%	1.7%	2.1%	3.1%	3.0%	2.1%	1.7%	2.0%	2.2%	2.6%	3.0%	2.6%	2.6%	1.6%	1.0%	1.0%	1.4%	1.6%	1.7%	1.7%	1.4%
Use per customer (kWh) [3]	12,275	12,234	12,339	12,526	12,609	12,602	12,575	12,315	12,329	12,273	12,153	12,055	12,042	12,028	11,963	11,623	11,075	10,877	10,940	11,124	10,863	10,937	10,854
% Change		-0.3%	0.9%	1.5%	0.7%	-0.1%	-0.2%	-2.1%	0.1%	-0.5%	-1.0%	-0.8%	-0.1%	-0.1%	-0.5%	-2.8%	-4.7%	-1.8%	0.6%	1.7%	-2.4%	0.7%	-0.8%

Footnotes. See also PGE Response to OPUC Data Request 443(b).

1. Mid-year estimate of the seven Oregon counties served by PGE. Source is Portland State University's Population Research Center.
2. Weather-normalized electricity delivered to PGE Residential customers in Rate Schedules 7 (Residential; 99.9%) and 15 (Outdoor Area Lighting; 0.1%)
3. Use per Customer (kWh) is Residential kWh divided by # of Residential Customers

September 5, 2008

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to OPUC Data Request
Dated August 25, 2008
Question No. 443

Request:

Regarding page 43 of PGE's "Integrated Resource Plan 2009: Second Stakeholder Presentation & Discussion" document distributed to parties attending the IRP Stakeholder meeting held on August 21, 2008:

a. Please provide a table documenting the values represented in the "Population and Residential Energy Use" graph, including the underlying values from which the three series of percentage change values were calculated, for each year 1986 through 2007. Please include the underlying 1985 values used in calculating the three 1986 percentage change values.

b. Please describe each of the three underlying data series contained in the "Population and Residential Energy Use" graph; i.e., 7-Co. Population, Residential, and Res. Use per Customer. (2) Please indicate whether or not the Residential energy use values have been weather-normalized. (3) Additionally, please describe how the Residential energy usage portrayed in the graph differs from PGE's current Schedule 7 energy usage; i.e., describe how the classification "Residential" differs from PGE's Rate Schedule 7.

c. Please identify the source for each of the three underlying data series contained in the "Population and Residential Energy Use" graph; i.e., 7-Co. Population, Residential, and Res. Use per Customer.

d. Please provide a letter-sized gray scale paper copy of the page 43 graph "Population and Residential Energy Use." Please include on the same page as the gray scale graph a legend denoting how each data series is represented in the graph.

Response:

a. See Attachment 443-A. This attachment is an Excel file containing the "raw" data as well as the calculated percentages used in the "Population and Residential Energy Use" graph, PGE's "Integrated Resource Plan (IR) 2009 Second Stakeholder Presentation & Discussion", page 43.

b. The population is the mid-year estimate of the seven counties that PGE serves (Clackamas, Columbia, Marion, Multnomah, Polk, Washington and Yamhill) supplied by Portland State University (PSU) Population Research Center, the state's official demographic clearing house (http://www.pdx.edu/prc/). Residential Energy Use is annual energy (in million kWh) delivered to our residential customers and (residential) use per customer is calculated by dividing the annual total residential customers into annual residential energy use. All energy use figures in the graphs are "adjusted" to average (or normal) weather conditions. Residential energy use consists of energy delivered under (PGE) Rate Schedule 7 (99.9%) and residential lighting.

c. The population data are obtained from PSU Population Research Center See answer to 443(b) above. Energy data are PGE's historical data as recorded by in our "Revenue Report" and adjusted by our weather-normalization models.

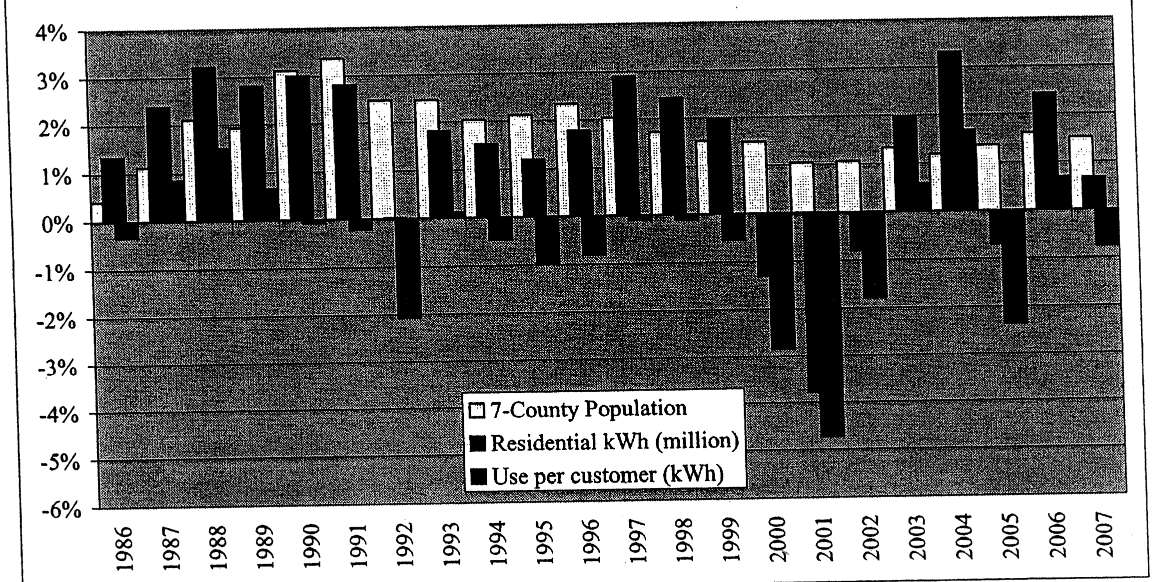
d. Attachment 443-A also includes in full size the same graph used in our 2009 IRP Presentation & Discussion.

UE 197
Attachment 443-A

Excel File and Graph

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
7-County Population	1,429,750	1,435,700	1,451,900	1,482,600	1,511,300	1,558,500	1,610,910	1,650,780	1,691,510	1,726,050	1,762,760	1,804,190	1,841,000	1,872,840	1,901,470	1,929,850	1,950,050	1,970,700	1,996,950	2,020,650	2,048,245	2,081,145	2,112,595
% Change		0.4%	1.1%	2.1%	1.9%	3.1%	3.4%	2.5%	2.5%	2.0%	2.1%	2.4%	2.0%	1.7%	1.5%	1.5%	1.0%	1.1%	1.3%	1.2%	1.4%	1.6%	1.5%
Residential kWh (million)	5,611	5,686	5,823	6,010	6,179	6,365	6,545	6,546	6,665	6,768	6,848	6,971	7,173	7,349	7,495	7,398	7,118	7,061	7,201	7,440	7,388	7,568	7,619
% Change		1.3%	2.4%	3.2%	2.8%	3.0%	2.8%	0.0%	1.8%	1.5%	1.2%	1.8%	2.9%	2.4%	2.0%	-1.3%	-3.8%	-0.8%	2.0%	3.3%	-0.7%	2.4%	0.7%
# of Residential Customer	457,119	464,802	471,891	479,787	490,039	505,086	520,449	531,536	540,591	551,420	563,514	578,254	595,683	610,952	626,539	636,449	642,708	649,145	658,232	668,830	680,093	691,931	701,952
% Change		1.7%	1.5%	1.7%	2.1%	3.1%	3.0%	2.1%	1.7%	2.0%	2.2%	2.6%	3.0%	2.6%	2.6%	1.6%	1.0%	1.0%	1.4%	1.6%	1.7%	1.7%	1.4%
Use per customer (kWh)	12,275	12,234	12,339	12,526	12,609	12,602	12,575	12,315	12,329	12,273	12,153	12,055	12,042	12,028	11,963	11,623	11,075	10,877	10,940	11,124	10,863	10,937	10,854
% Change		-0.3%	0.9%	1.5%	0.7%	-0.1%	-0.2%	-2.1%	0.1%	-0.5%	-1.0%	-0.8%	-0.1%	-0.1%	-0.5%	-2.8%	-4.7%	-1.8%	0.6%	1.7%	-2.4%	0.7%	-0.8%

Population and Residential Energy Use



CASE: UE 197
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1302

Exhibits in Support
of Surrebuttal Testimony

September 15, 2008

Staff/1302
Storm/1

UE 197 PGE

Schedule 123 Residential Sales Normalization Adjustment

Staff Example C

	Customer-Based Fixed Costs Revenue					Energy-Based Fixed Cost Revenue					
Year	Customer Growth Rate[1]	Customers	Monthly Fixed Costs per Customer	Monthly Revenue	Annual Customer-Based Revenue	Usage per Customer Growth Rate[2]	Customers	Annual Customer kWh	Total MWH	Volumetric Fixed Costs per kWh	Annual Energy-Based Revenue
2009		716,468	$45.59	$32,663,791	$391,965,496		716,468	10,765	7,712,700	$0.05082	$391,959,426
2010	1.3%	726,058	$45.59	$33,100,970	$397,211,634	-0.3%	726,058	10,729	7,789,615	$0.05082	$395,868,224
2011	2.4%	743,462	$45.59	$33,894,410	$406,732,922	0.9%	743,462	10,821	8,044,833	$0.05082	$408,838,389
2012	3.2%	767,365	$45.59	$34,984,154	$419,809,848	1.5%	767,365	10,985	8,429,403	$0.05082	$428,382,260
2013	2.8%	788,995	$45.59	$35,970,279	$431,643,349	0.7%	788,995	11,058	8,724,881	$0.05082	$443,398,450
2014	3.0%	812,732	$45.59	$37,052,455	$444,629,463	-0.1%	812,732	11,052	8,981,954	$0.05082	$456,462,911
2015	2.8%	835,652	$45.59	$38,097,375	$457,168,503	-0.2%	835,652	11,028	9,215,402	$0.05082	$468,326,745
2016	0.0%	835,818	$45.59	$38,104,943	$457,259,315	-2.1%	835,818	10,800	9,026,769	$0.05082	$458,740,424
2017	1.8%	851,064	$45.59	$38,800,004	$465,600,047	0.1%	851,064	10,813	9,202,324	$0.05082	$467,662,122
2018	1.5%	864,126	$45.59	$39,395,521	$472,746,252	-0.5%	864,126	10,763	9,300,666	$0.05082	$472,659,849
2019	1.2%	874,431	$45.59	$39,865,298	$478,383,580	-1.0%	874,431	10,658	9,319,404	$0.05082	$473,612,096
2020	1.8%	890,085	$45.59	$40,578,987	$486,947,849	-0.8%	890,085	10,572	9,409,936	$0.05082	$478,212,962
2021	2.9%	915,955	$45.59	$41,758,379	$501,100,548	-0.1%	915,955	10,561	9,673,299	$0.05082	$491,597,040
2022	2.4%	938,345	$45.59	$42,779,141	$513,349,689	-0.1%	938,345	10,549	9,898,269	$0.05082	$503,030,048
2023	2.0%	957,070	$45.59	$43,632,832	$523,593,979	-0.5%	957,070	10,492	10,041,107	$0.05082	$510,289,032
2024	-1.3%	944,602	$45.59	$43,064,413	$516,772,951	-2.8%	944,602	10,194	9,628,886	$0.05082	$489,339,986
2025	-3.8%	908,887	$45.59	$41,436,177	$497,234,123	-4.7%	908,887	9,713	8,827,713	$0.05082	$448,624,362
2026	-0.8%	901,591	$45.59	$41,103,531	$493,242,378	-1.8%	901,591	9,539	8,600,407	$0.05082	$437,072,665
2027	2.0%	919,510	$45.59	$41,920,478	$503,045,741	0.6%	919,510	9,594	8,822,188	$0.05082	$448,343,570
2028	3.3%	950,028	$45.59	$43,311,772	$519,741,262	1.7%	950,028	9,756	9,268,277	$0.05082	$471,013,856
2029	-0.7%	943,320	$45.59	$43,005,957	$516,071,479	-2.4%	943,320	9,526	8,986,516	$0.05082	$456,694,746
2030	2.4%	966,318	$45.59	$44,054,444	$528,653,329	0.7%	966,318	9,592	9,268,707	$0.05082	$471,035,687
2031	0.7%	972,854	$45.59	$44,352,402	$532,228,829	-0.8%	972,854	9,519	9,260,391	$0.05082	$470,613,065

Sales Normalization Adjustment

Year	Customer-Based Revenue	Energy-Based Revenue	Nominal SNA Amount	Overall Revenue	Percent Change	SNA with +2% Constraint	Annual Deferred SNA	Cumulative Deferred SNA
2009	$391,965,496	$391,959,426	$6,070	$839,815,814	0.00%	$ 6,070	$ -	$ -
2010	$397,211,634	$395,868,224	$1,343,411	$848,190,839	0.16%	$ 1,343,411	$ -	$ -
2011	$406,732,922	$408,838,389	($2,105,467)	$875,980,833	-0.24%	$ (2,105,467)	$ -	$ -
2012	$419,809,848	$428,382,260	($8,572,412)	$917,855,708	-0.93%	$ (8,572,412)	$ -	$ -
2013	$431,643,349	$443,398,450	($11,755,101)	$950,029,533	-1.24%	$ (11,755,101)	$ -	$ -
2014	$444,629,463	$456,462,911	($11,833,447)	$978,021,564	-1.21%	$ (11,833,447)	$ -	$ -
2015	$457,168,503	$468,326,745	($11,158,242)	$1,003,441,124	-1.11%	$ (11,158,242)	$ -	$ -
2016	$457,259,315	$458,740,424	($1,481,109)	$982,901,385	-0.15%	$ (1,481,109)	$ -	$ -
2017	$465,600,047	$467,662,122	($2,062,076)	$1,002,017,097	-0.21%	$ (2,062,076)	$ -	$ -
2018	$472,746,252	$472,659,849	$86,403	$1,012,725,270	0.01%	$ 86,403	$ -	$ -
2019	$478,383,580	$473,612,096	$4,771,484	$1,014,765,564	0.47%	$ 4,771,484	$ -	$ -
2020	$486,947,849	$478,212,962	$8,734,888	$1,024,623,421	0.85%	$ 8,734,888	$ -	$ -
2021	$501,100,548	$491,597,040	$9,503,509	$1,053,300,268	0.90%	$ 9,503,509	$ -	$ -
2022	$513,349,689	$503,030,048	$10,319,641	$1,077,796,734	0.96%	$ 10,319,641	$ -	$ -
2023	$523,593,979	$510,289,032	$13,304,947	$1,093,349,900	1.22%	$ 13,304,947	$ -	$ -
2024	$516,772,951	$489,339,986	$27,432,965	$1,048,464,283	2.62%	$ 20,969,286	$ 6,463,680	$ 6,463,680
2025	$497,234,123	$448,624,362	$48,609,762	$961,226,618	5.06%	$ 19,224,532	$ 29,385,229	$ 35,848,909
2026	$493,242,378	$437,072,665	$56,169,712	$936,475,849	6.00%	$ 18,729,517	$ 37,440,195	$ 73,289,104
2027	$503,045,741	$448,343,570	$54,702,171	$960,624,991	5.69%	$ 19,212,500	$ 35,489,672	$ 108,778,776
2028	$519,741,262	$471,013,856	$48,727,407	$1,009,198,551	4.83%	$ 20,183,971	$ 28,543,436	$ 137,322,212
2029	$516,071,479	$456,694,746	$59,376,734	$978,518,296	6.07%	$ 19,570,366	$ 39,806,368	$ 177,128,580
2030	$528,653,329	$471,035,687	$57,617,643	$1,009,245,326	5.71%	$ 20,184,907	$ 37,432,736	$ 214,561,316
2031	$532,228,829	$470,613,065	$61,615,764	$1,008,339,813	6.11%	$ 20,166,796	$ 41,448,967	$ 256,010,283

Note: 2009 values for Customers and Annual Customer kWh are from Exhibit PGE/1208 page 2.

1. Customer Growth Rate is based on PGE history for period 1986 - 2007.
2. Usage per Customer Growth Rate based on PGE history for period 1986 - 2007.

UE 197 PGE

Schedule 123 Residential Sales Normalization Adjustment

Staff Example D

Customer-Based Fixed Costs Revenue

Year	Customer Growth Rate[1]	Customers	Monthly Fixed Costs per Customer	Monthly Revenue	Annual Customer-Based Revenue
2009		716,468	$45.59	$32,663,791	$391,965,496
2010	2.4%	733,982	$45.59	$33,462,241	$401,546,887
2011	2.0%	748,629	$45.59	$34,130,005	$409,560,066
2012	-1.3%	738,877	$45.59	$33,685,383	$404,224,595
2013	-3.8%	710,940	$45.59	$32,411,762	$388,941,142
2014	-0.8%	705,233	$45.59	$32,151,563	$385,818,762
2015	2.0%	719,250	$45.59	$32,790,587	$393,487,044
2016	3.3%	743,121	$45.59	$33,878,870	$406,546,435
2017	-0.7%	737,874	$45.59	$33,639,658	$403,675,897
2018	2.4%	755,863	$45.59	$34,459,795	$413,517,536
2019	0.7%	760,975	$45.59	$34,692,860	$416,314,325

Energy-Based Fixed Cost Revenue

Usage per Customer Growth Rate[2]	Customers	Annual Customer kWh	Total MWH	Volumetric Fixed Costs per kWh	Annual Energy-Based Revenue
	716,468	10,765	7,712,700	$0.05082	$391,959,426
-0.1%	733,982	10,752	7,892,073	$0.05082	$401,075,175
-0.5%	748,629	10,694	8,005,960	$0.05082	$406,862,898
-2.8%	738,877	10,390	7,677,289	$0.05082	$390,159,835
-4.7%	710,940	9,900	7,038,499	$0.05082	$357,696,513
-1.8%	705,233	9,723	6,857,264	$0.05082	$348,486,132
0.6%	719,250	9,780	7,034,094	$0.05082	$357,472,633
1.7%	743,121	9,944	7,389,769	$0.05082	$375,548,072
-2.4%	737,874	9,710	7,165,116	$0.05082	$364,131,180
0.7%	755,863	9,777	7,390,112	$0.05082	$375,565,478
-0.8%	760,975	9,703	7,383,481	$0.05082	$375,228,514

Sales Normalization Adjustment

Year	Customer-Based Revenue	Energy-Based Revenue	Nominal SNA Amount	Overall Revenue	Percent Change	SNA with +2% Constraint	Annual Deferred SNA	Cumulative Deferred SNA
2009	$391,965,496	$391,959,426	$6,070	$839,815,814	0.00%	$ 6,070	$ -	$ -
2010	$401,546,887	$401,075,175	$471,712	$859,347,300	0.05%	$ 471,712	$ -	$ -
2011	$409,560,066	$406,862,898	$2,697,168	$871,748,127	0.31%	$ 2,697,168	$ -	$ -
2012	$404,224,595	$390,159,835	$14,064,760	$835,959,994	1.68%	$ 14,064,760	$ -	$ -
2013	$388,941,142	$357,696,513	$31,244,629	$766,403,787	4.08%	$ 15,328,076	$ 15,916,553	$ 15,916,553
2014	$385,818,762	$348,486,132	$37,332,630	$746,669,541	5.00%	$ 14,933,391	$ 22,399,239	$ 38,315,792
2015	$393,487,044	$357,472,633	$36,014,411	$765,924,099	4.70%	$ 15,318,482	$ 20,695,929	$ 59,011,721
2016	$406,546,435	$375,548,072	$30,998,363	$804,652,698	3.85%	$ 16,093,054	$ 14,905,309	$ 73,917,030
2017	$403,675,897	$364,131,180	$39,544,717	$780,190,762	5.07%	$ 15,603,815	$ 23,940,902	$ 97,857,932
2018	$413,517,536	$375,565,478	$37,952,058	$804,689,993	4.72%	$ 16,093,800	$ 21,858,259	$ 119,716,190
2019	$416,314,325	$375,228,514	$41,085,811	$803,968,011	5.11%	$ 16,079,360	$ 25,006,451	$ 144,722,641

Note: 2009 values for Customers and Annual Customer kWh are from Exhibit PGE/1208 page 2.

1. Customer Growth Rate is based on PGE history for period 1998 - 2007.
2. Usage per Customer Growth Rate based on PGE history for period 1998 - 2007.

Staff/1302
Storm/2

CASE: UE 197
WITNESS: Paul Rossow

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1400

Surrebuttal Testimony

September 15, 2008

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Paul Rossow. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551. I am a Utility Analyst in the Electric and Natural Gas Division of the Utility Program of the Public Utility Commission of Oregon.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement appears in Exhibit Staff/201, Rossow/1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will identify PGE's business process changes that support staff's proposal to set PGE's uncollectibles rate for the 2009 test period at 0.38 percent, the company's most recent full year of actual experience in 2007.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Staff Exhibit 1401. Exhibit 1401 consists of a copy of PGE's Business Case Cost and Benefit Assumptions Advanced Metering Infrastructure Project report that was submitted to the Oregon Public Utility Commission dated April 5, 2007 (April 5, 2007 business case).

Q. HAS PGE IDENTIFIED OTHER POSSIBLE FACTORS THAT AFFECT THE OVERALL UNCOLLECTIBLES RATE?

A. At PGE/1700/Hawke/12, PGE states that PGE's uncollectibles rate is not directly tied to the unemployment rate, but that there are other drivers that affect that rate and impact the economy as a whole. PGE then demonstrates how the 2008 light and power portion of its uncollectibles rate has increased slightly over 2007.

This demonstration does not address PGE's overall 2008 uncollectibles rate and therefore may not paint a true picture of the actual overall rate.

Q. DID STAFF LOOK AT PGE'S OVERALL HISTORIC TREND FOR UNCOLLECTIBLES?

A. Yes. Staff's uncollectible adjustment looks at PGE's overall historic trend for uncollectibles and attempts to set a reasonable projection for the 2009 test period. Staff acknowledges that all measures in this case are dynamic, not static, and that economic outlooks, including employment statistics, can change dramatically over short and long periods of time. However, the historic look at the overall rate generally produces a fairly reasonable outcome. *See* Staff/200, Rossow/3-4.

In addition, Staff would ask that the Commission consider PGE's upcoming deployment of Automated Meter Infrastructure (AMI). In its April 5, 2007 business case, PGE makes assumptions about how the new remote disconnect feature of AMI will improve cash flow and reduce working capital. In its case, PGE assumes that 60% of potential late-paying customers affected by Customer Selected Due Date and remote disconnect will now pay sooner to avoid paying late fees and that ultimately this will improve PGE's cash flow that is measured as a reduction in working capital. *See* Exhibit Staff/Rossow/1401, page 11 of 17.

While Staff recognizes that these factors are not currently in place and the Company will not see the benefits completely until full-deployment (2010), much of the deployment will take place by 2009 and it will be completed only one year after the implementation of this general rate proceeding. In its UE 189 Stipulation, Staff, PGE and other Parties have agreed to a condition that PGE will file another general rate case by 2012 in order to capture all the benefits of AMI; however, 2012 is three years after the implementation of the current proceeding.

Q. WHAT REASONABLE UNCOLLECTIBLE OVERALL RATE DO YOU RECOMMEND THE COMMISSION ADOPT IN THIS PROCEEDING?

A. It is not reasonable to allow PGE to increase its uncollectible rate to 0.48%. Staff's forecast of a rate of 0.38% is reasonable and recommends that the Commission adopt an overall uncollectible rate of 0.38%.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

CASE: UE 197
WITNESS: Paul Rossow

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1401

Exhibits in Support
of Surrebuttal Testimony

September 15, 2008

Business Case Cost and Benefit Assumptions
Advanced Metering Infrastructure Project

Portland General Electric Company
April 5, 2007

1. Introduction

The following information summarizes the major cost and benefit assumptions contained in the revised economic model submitted to the OPUC as Attachment A on March 7, 2007 in support of PGE's advanced metering infrastructure ("AMI") business case. This document covers the project's capital costs, incremental expenses, recurring O&M costs, benefits and capital revenue requirement. The economic model includes costs for both the Status Quo (current practice) and the proposed AMI system. Benefits are the net of savings versus recurring costs of AMI compared with the Status Quo.

The discussion below focuses on the costs, benefits and underlying assumptions for the proposed AMI system. In each subsection, PGE notes the locations within the business case model where data can be found and identifies key assumptions used in the model. Costs are shown for the AMI deployment years of 2007, 2008 and 2009. Costs for the first full year of operations (2010) also are shown to provide the reader with the basis for the continuing cost and benefit stream over the remaining years of the project life.

2. Deployment and Meter Cost Assumptions

Table 2-1
(Dollars in 1000s)

Line	Item	Tab	Cell	2007	2008	2009	2010
1	Meter Deployment (units)	Cap Assumptions	J49: M56	158,400	445,600	240,787	14,974
1a	Failed Meter Replacements	Cap Assumptions	K35:M36	0	166	723	1,352
1b	Avg. Installed Meter Cost	Cap Assumptions	J62:M68	$130.35	$118.40	$120.50	$136.50
2	Total Meter Cost	CAPEX	J86	$20,865	$55,784	$30,900	$2,228

Meter Deployment (Line 1)

The deployment schedule in the economic model of March 2007 described in this document is unchanged from the revised economic model submitted in October 2006. The preliminary draft AMI Field Deployment Plan PGE submitted in January 2007 shows a schedule that assumes a June 2007 AMI project approval from the OPUC. For comparison, this schedule starts about six months later and finishes three months later than the deployment schedule assumed in the economic model.

In the economic model, PGE conducts the AMI vendor system acceptance test (SAT) during the first 7 months of 2007. This entails installing 15,000 meters and communication infrastructure for this purpose. In the model, full deployment starts in July of 2007 and ramps up to a deployment rate of about 36,000 meters month by October. A total of 158,400 meters are installed in 2007. The deployment proceeds at a rate of about 37,000 meters per month in 2008 and 2009. The full deployment ends in July of 2009, but the total numbers for 2009 include new construction meters (i.e., new meters added as the result of new development or growth) through December.

The total meters installed in the project period (845,676) is based on the actual number of existing meters as of the end of 2006 plus a net gain primarily from new construction of about 15,000 meters per year. The annual meter growth rate is based on PGE short-term forecast of 2005.

Failed Meter Replacements (Line 1a)

The meter count for 2010 and subsequent years is based solely on this net gain in meters per year plus replacement of failed meters. The details by type of meter installed are shown on the Capital Assumptions tab, cells J49:M55. The count of meters also includes replacement for failed meters not covered by warranty; these quantities are shown in cells K35:M36. The failure rate basis is an Iowa R18 curve, which is the standard depreciation accounting schedule (shown in cells BG27:BV42) used to define a useful project life. This results in a more conservative estimate than the manufacturer's representations.

Average Installed Meter Cost (Line 1b)

The average installed cost per meter includes the combined average cost of all AMI meter types in the volumes expected to be deployed, including the costs of meter rings, meter seals, installation labor, meter testing, and direct scheduling and supervision of the meter installation process.

Most of the meters will be installed by our contract meter installer (CMI). PGE employees will continue to install all new construction meters at commercial and residential sites. PGE also plans to install AMI meters in all sites with external current transformers (i.e., transformer-rated meters).

Table 2-2

Item	Tab	Cells	Basis
▪ Meters (average cost)	Cap Assumptions	J62:M68	Bid received by PGE in 2006 from prospective vendor
▪ CMI Meter Installation, Testing, Scheduling and Supervision	Cap Assumptions	J166:M169 J244:L244	Bid received by PGE in 2006 from prospective vendor
▪ PGE Meter Installation, Testing, Scheduling, Supervision and Project Management	Cap Assumptions	J138:M157 G202:H210	Current PGE labor costs (loaded) multiplied by average meter installation times, including travel time, based on PGE experience
▪ PGE Indirect Meter Installation	Cap Assumptions	J214:M234	Current hours and labor rates for testing, scheduling, supervision and general project management
▪ % of Meters Installed by Each Type of Installer	Cap Assumptions	J105:M130	CMI to install single-phase and three-phase self-contained meters with no external wiring
▪ Meter Rings, Seals and other Peripheral Materials	Cap Assumptions		PGE's most recent procurement costs

The average installed meter costs are higher in 2007 and 2010 because of higher prices based on lower volume purchases in those years and the effect of higher project management costs per meter at lower volume. The labor cost for new construction residential meters is not included since the work process is unchanged compared to current practice and this work is done mainly by distribution line crews, not PGE's Meter Services department.

Meter Services' planned work installing transformer-rated meters will be done primarily by meterman who normally do sample testing of existing meters; this activity is assumed to be deferred during the AMI deployment period. Since this type of work is expensed and the installation work is capital, the cost of this work is included twice, once in the O&M Summary section of the model that shows all full-time equivalents (FTEs) of personnel as O&M, and again in the capital cost of AMI installation. This type of double counting occurs in other areas of the model; the method to deal with this is further described in Section 4, O&M Credit (Line 7).

Total Meter Cost (Line 2)

The appropriate multiplication for the various assumptions associated with total meter cost is calculated in CAPEX rows J18:M80. Total meter cost, Line 2 of Table 2-1 above, is then derived as the product of the average meter cost times the quantity of meters deployed plus a contingency shown in Row 84 on the CAPEX spreadsheet.

3. Other Capital Cost Assumptions

Table 3-1
(Dollars in 1000s)

Line	Item	Tab	Cell	2007	2008	2009	2010
3	Communication System	CAPEX	J122	$2,583	$2,405	$570	$0
4	IT Infrastructure (with contingency)	CAPEX	J153	$10,265	$4,900	$1,240	$0

Communication System (Line 3)

Table 3-2

Item	Tab	Cells	Basis
▪ Vendor-provided Field Equipment	Cap Assumptions	J253-L255	Vendor bids received in 2006
▪ Vendor-provided Network Services	Cap Assumptions	J265-L265	Vendor bids received in 2006

The assumptions for vendor-provided field equipment and services to install and optimize the AMI communication network are shown in the Capital Assumptions tab, cells J253:L265. The totals shown in Line 3 of Table 3-1 are calculated in rows 96 and 118 in the CAPEX tab.

IT Infrastructure (Line 4)

Table 3-3

Item	Tab	Cells	Basis
▪ Computer Servers, Storage, and other related hardware	Cap Assumptions	I276:L276 I278: L279 I281:L281	Price quotes based on AMI vendor specs & quotes for MDC storage
▪ Purchase Software Licenses	Cap Assumptions	I280:L280	Vendor quotations
▪ System Modifications and New Application Development	Cap Assumptions	I272:L275 I277: L277	IT estimates based on documented business requirements

The capital assumptions for expenditures in Table 3-1, Line 4 above are shown in the Capital Assumptions tab, cells I272:L281. There are three primary areas of costs: (1) computer hardware: servers, storage, and back office network equipment; (2) software from vendors; and (3) development of applications at PGE to support the new business process. About $6 million is for computer hardware, $1.4 million for various software, $6.6 million for application development to support the new business processes, and $2.4 million for contingency. 2007 expenditures are much higher than the other years because most of the software and server hardware is purchased at the beginning of the project. Also $1.3 million in mostly application development that occurred in 2006 is shown in 2007. Our answers to data request #521 in UE 180 explained what the development task included in the $6.6 million expenditure; however, the cost estimates have been revised since that data request based on more detailed information.

4. Incremental One-Time Project Expense Assumptions

Table 4-1
Dollars in 1000s

Line	Item	Tab	Cell	2007	2008	2009	2010
5	Incremental Expense	O&M Summary	See below	$2,683	$2,705	$670	$0
7	O&M Credit	O&M Summary	D117,118 – D46,47	-$3,132	-$1,848	-$879	$71
P	**Total One-Time Expense**			**$132**	**$3,324**	**$2,415**	**$71**

Incremental Expense (Line 5)

"Incremental Expense," Line 5 of Table 4-1, is the sum of rows, in the O&M Summary spreadsheet, 92, 95 through 102, 116, and the difference of row 60 less row 12 with loadings added. The assumptions, respectively, for these rows are listed in Table 4-2 below.

Table 4-2

Item	Tab	Cells	Basis
▪ Temporary NDO Expense	O&M Assumptions	D75:F76	Supervisor estimate
▪ IT Project Expense	O&M Summary	D99:F99	IT cost estimate
▪ Severance Costs	FTE Counts Labor Summary	D37, 41, 61 E13:14, 31	PGE Severance Policy

▪ Outplacement Cost	FTE Counts	D44:F48	PGE Human Resources
▪ PGE Employees in Project Office	O&M Assumptions	D72:F72	AMI Project Manager requirements
▪ Project Office Contract Labor	O&M Assumptions	D66:F67	AMI Project Manager requirements
▪ Project Office Contingency	O&M Summary	D116:F116	AMI Project Manager
▪ Communication & Misc. Expense	O&M Assumptions	D80:F80	AMI Project Manager estimate

"Temporary NDO Expense" is for workers in Network Data Operations (NDO) that are needed to validate new meter installations and to set up meter installation exceptions in the AMI system. These positions are needed since, for most of the project, there is a need to support a meter exchange rate 20 times higher than normal. "IT Project Expense" includes management oversight, but most of the dollars are for minor code modifications after new applications are placed in service.

"Severance Costs" are calculated for FTE positions that are eliminated due to AMI. "Outplacement Costs" are based on the historical costs of providing HR services to employees who leave the company.

"PGE Employees in Project Offices" reflects approximately 10 needed to manage the overall project and field activity, data collection for planning and scheduling, project communications, business process changes across more than 10 departments, organizational change management and project cost control. "Project Office Contract Labor" includes specialty services required during the project period (e.g., schedule management, legal review, system testing, administrative support, contract administration, etc.). The "Project Office Contingency" expense is for unexpected project costs.

"Communications and Misc. Expenses" is based on the AMI Communication Plan submitted to the OPUC plus some miscellaneous costs. Most of this is for customer communications during the deployment period.

O&M Credit (Line 7)

As discussed previously under Average Installed Meter Cost in Section 2, an O&M credit is needed to correctly calculate the true incremental expense during the project period. Work in three PGE departments (Meter Services, IT staff within NDO and staff of other PGE IT departments) is mostly expensed in the Status Quo case but, during the AMI project, will be charged to AMI-related capital jobs. The capital work of these employees shows up on the CAPEX spreadsheet in the columns discussed in Sections 2 & 3 above. For PGE employees, these costs are repeated in columns AH through AK. The sums of these columns are totaled respectively for the AMI and Status Quo cases in cells I163:M164 and I216:M217 in the CAPEX spreadsheet. These totals, in turn, show up as a credit in cells C117:G118 and C46:G48 respectively in the O&M Summary spreadsheet. The O&M summary sheet tallies 100% of labor cost of these departments, equally, in both the Status Quo and AMI cases. The amount of the credit in each case reduces expense in the AMI case equal to the work of these employees that is capitalized. Since these employees do more capitalized work during the deployment period than normal, there is a net credit to O&M expense in these years.

5. Recurring AMI Expense Assumptions

Table 5-1

Dollars in 1000s

Line	Item	Tab	Cell	2007	2008	2009	2010
8	Incremental FTE	See below		$176	$549	$765	$1,015
9	Field Comm. Services	O&M Summary	D103	$40	$210	$233	$239
10	Software Support Fees	O&M Summary	D104	$0	$21	$304	$578
11	IT Maint. and Support	O&M Summary	D104	$5	$407	$492	$504
R	**Total of Recurring Cost**			**$222**	**$1,187**	**$1,795**	**$2,337**

Incremental FTE (recurring) (Line 8)

Lines 8 through Line 11 of Table 5-1 list incremental recurring costs that extend through the life of the project. The calculation of recurring PGE labor costs is the most complicated part of the model due to several factors:

- Capitalized labor is treated differently than when expensed
- Benefit loadings vary depending on component and whether capital or expense
- The work performed during the AMI project changes compared to post deployment
- Some departments[1] gain FTE and some see reductions
- Departments with minor involvement are modeled differently than those with major impact
- The model accounts for the increase in FTEs due to a growing number of customers and meters

In this document, to simplify the explanation of assumptions, most labor increases or savings are explained by stating the number of FTE added or reduced multiplied by the average annual loaded cost of these FTEs. The complicating factors listed above are referenced only when necessary to explain the simplified assumptions. These simplified assumptions lead to some error. The amount of error is small and calculated in Section 8 of this document.

In the model, incremental FTE are treated in two ways based on the level of department involvement. The primary assumptions for these two methods are indicated in Table 5-2 below.

Table 5-2

Item	Tab	Cells	Basis
▪ Incremental FTE in NDO, Meter Services	O&M Assumptions	D69:G73	Affected PGE managers
▪ Incremental FTE in Contact Center	O&M Assumptions	D107:G107	PGE Contact Center manager

"Incremental FTE NDO, Meter Services" represents new FTE positions in the highly involved departments needed to support the AMI system. There are 10 new positions, with an average loaded labor cost of $89,323, in 2010:

[1] In the economic model PGE refers to "departments" as responsibility centers or "RCs."

- Two metermen to deal with somewhat higher commercial meter failures (there are two independent failure modes now, the meter and its communication module)
- Three additional IT positions are required to support the new automated businesses processes and the very large increase in data storage created by the AMI system
- Two positions, a database analyst and a lineman, to handle the increased amount of service transformer-level metering needed to support increased identification of energy theft and unaccounted for energy losses
- Three additional positions in NDO to support the large increase in the number of AMI meters.

"Incremental FTE in Contact Center" includes incremental costs for 2 FTEs in the Customer Contact Center due to increased call volume generated by the expected increased number of service disconnects for non-payment because payments will no longer be taken in the field. These costs show up in row 108 on the O&M Summary tab.

Recurring IT Expense (Lines 9, 10, & 11)

Lines 9 through 11 of Table 5-1 cover costs incurred by IT departments: These costs include (1) standard telecom service to transport data from field-based AMI collectors back to PGE; (2) lease of physical infrastructure for attaching the collectors to towers; (3) lease of the AMI vendor-owned radio frequency; (4) software maintenance for vendor, server and storage application software; (5) spare parts to replace failed IT equipment; and (6) phone technical support from IT vendors.

Table 5-3

Item	Tab	Cells	Basis
▪ Field Communications Services	O&M Assumptions	D80:F80	IT estimates based on number of sites
▪ Software Support Fees	O&M Assumptions	H95:J95	Vendor quotations
▪ IT Maintenance & Support	O&M Assumptions	G97:I97	IT estimates based on equip. purchased

6. Benefits Assumptions

The following section covers benefits anticipated by AMI. These benefits are those quantified in the AMI business case. Potential future benefits, such as those described in PGE's submittal to the OPUC on Customer and System-Related Benefits and/or benefits not quantified in the business case, are not included.

Table 6-1. Benefits Summary

Dollars in 1000s

Line	Item	Tab	Cell	2007	2008	2009	2010
12	Reduced Meter Reading Costs	O&M Summary	D54-D7 + loadings	-$420	-$3,479	-$6,657	-$8,128
13	Reduced FCR Costs	"	D55-D8 + loadings	-$41	-$473	-$1,411	-$1,984
14	Reduced Overtime	"	D66-D18	-$5	-$124	-$283	-$368
15	Reduced Costs Due to Automated Move-In/Move Out	"	D109	$0	-$93	-$433	-$644

16	Fuel & Maintenance Savings – Meter Readers & FCRs	"	D71-D23	-$9	-$168	-$342	-$429
17	Miscellaneous Costs & Materials Expense Reduction	"	(D78, D85,D 87->91) - (D30, 37, 44)	-$9	-$137	-$339	-$473
18	CSDD Late Pay	"	D111	$0	$0	-$850	-$1,731
19	CSDD & RD Reduced Working Capital	"	D110	$0	-$408	-$415	-$422
20	Saved Power Cost Due to Remote Disconnects	"	D113	-$111	-$351	-$1,072	-$1,382
21	UFE Reductions	"	D112	$0	-$600	-$1,656	-$1,871
22	A&G Reductions	"	D107	$0	-$31	-$236	-$461
23	Increase KWh (previously unbilled)	"	D114	-$13	-$93	-$177	-$180
24	Improved Meter Accuracy	"	D115	-$31	-$227	-$440	-$524
25	Special Meter Costs, TOU Load Research, etc.	"	D145	-$173	-$195	-$218	-$243
B	**Total Benefits**			-$811	-$6,379	-$14,528	-$18,840
N	**Total Net Benefits**		Sum P, R, & B	-$458	-$1,868	-$10,318	-$16,432

Assumptions of Reduced Meter Reading Costs (Line 12)

Table 6-2

Item	Tab	Cells	Basis
▪ Reduced Meter Reading Costs	O&M Summary	D54-D7 + loadings	Reduction from 126 FTE to 12 FTE

The Meter Reading department has 119 employees in 2007; this grows to 126 by 2010 under the Status Quo case (see Labor Summary tab, row 9). Under the AMI case (see row 106), this department will be reduced to 12 FTEs in 2010 for a net reduction of 114 with an average hourly wage of $21.32 in 2010 (see Labor Summary cells H110:111). The typical labor loadings are 36.25% (see O&M Assumptions cell C13) and average medical insurance is $10,970 per FTE in 2010 (see O&M Assumptions cell G10). The 2010 savings of $8,128,000 equals the calculation of the assumptions above (i.e., = 114*(21.32*2080*1.3625+10970). The ramp rate leading to the 2010 value is determined in the O&M Assumptions tab, rows 53, 54, 55, & 58. The 4% subtraction in row 58 exists to account for the lag that occurs to perform an additional month of manual reads for each meter to validate the automated reads.

Assumptions of Reduced Field Connect Representative Costs (Line 13)

Table 6-3

Item	Tab	Cells	Basis
▪ Reduced FCR Costs	O&M **Summary**	**D55-D8 + loadings**	High number of disconnects and move-in/move-out transactions for accounts in non-owner occupied housing units

The remote disconnect application creates five benefit streams; this section discusses the overall process changes and the benefits derived from labor reductions (line 13) for field connect reps (FCRs). Lines 14, 16, 20, & 21 in Table 6-1, described below, cover the other benefit streams.

When PGE analyzed the economics of installing remote disconnect meters on all residential housing, there were insufficient benefits to justify this choice. In exploring how to improve the economics, it was determined that the approximately 235,000 non-owner occupied dwellings in PGE's service territory, which make up about 30% of all residential dwellings, account for about two-thirds of all disconnects and about 80% of all move-in/move out transactions. The higher transaction rate in these locations justified the incremental cost of meters with disconnect relays. O&M Assumptions tab, row 64 shows the assumptions that lead to a reduction in the number of the FCRs by two-thirds by 2010.

Automation of the remote disconnect application, which will link the customer information, AMI system and customer notification systems, is planned for completion in mid-2008. Thus, the benefits are greatly reduced in 2008 and 2009 based on time-weighted average number of meters installed after the remote disconnect application is placed in service. In a calculation similar to the section above, a labor reduction of 21.7 FTE (Row 27 less row 124) in 2010 leads to a loaded labor savings of using an average wage of $28.35.

Assumptions of Reduced Overtime (Line 14)

Table 6-4

Item	Tab	Cells	Basis
▪ Reduced Overtime Costs	O&M Assumptions	G59:G64	Reduction in existing overtime costs based on percent of FTE reductions

The AMI case (O&M Summary tab, rows 63 and 64) calculates the reduction in overtime costs proportional to the FTE reductions for meter readers and field connect representatives shown in rows 59 and 64 of the O&M Assumptions tab.

Assumptions of Reduced Costs Due to Automated Move-In/Move-Out (Line 15)

Table 6-5

Item	Tab	Cells	Basis
▪ Reduced Move-In/Move-Out Costs	O&M Assumptions	G111:G113	Elimination of manual off-cycle meter reads and manual billing processes

Approximately 150,000 PGE customers terminate their electric service account annually. Since this usually does not occur at the time of the normal meter read, a special off-cycle read is required. Because the reading usually must be prorated to the actual move-out day, it also requires a manual process by the Billing department. With AMI, this work can be automated because every meter is read every day. The work load reduction from automation is estimated to be 13 FTEs in 2010 based on the number of off-cycle reads eliminated. The wage and FTE reduction assumptions are shown in O&M Assumptions tab rows 111 and 113.

Assumptions for Fuel & Maintenance Savings (Line 16)

Table 6-6

Item	Tab	Cells	Basis
▪ Fuel & Maintenance Savings	O&M Assumptions	B19:20	Historical mileage at forecasted fuel, fuel efficiency & maintenance costs

2007 in the departments with reductions is forecasted at 1.2 million miles based on 2006 data. At 15 miles per gallon and a price $2.15 per gallon the fuel cost would be $172K. The maintenance cost for vehicles is forecast to be $298K based on 2006 data. The sum of $470K is somewhat higher $428K shown in cell D23 of O&M Summary tab. Gasoline costs have increased more than inflation since the last update of this estimate in 2004. The reduction in fuel and maintenance costs is assumed to ramp up with savings proportional to the FTE reductions. See row 60 in the O&M Assumptions tab.

Reduction in Miscellaneous Costs and Materials (Line 17)

Table 6-7

Item	Tab	Cells	Basis
▪ Misc. Costs & Materials	O&M Summary	(D78, D85,D 87->91) - (D30, 37, 44	Based on 2006 expenses filed in UE180 for departments with FTE reductions

Savings are based on the percentages listed in rows 61, 62, & 63, 64 of O&M Assumptions applied to the 2006 expenses filed in UE 180 for the departments listed in rows 25 through 44 in the O&M Summary tab. It should be noted that reductions only occur in the departments with FTE reductions.

CSDD Late Pay (Line 18)

Table 6-8

Item	Tab	Cells	Basis
▪ CSDD Late Pay	O&M Assumptions	G120:123	See Worksheet 1

Reading every meter every day means that meter read dates are no longer constrained to reduce labor costs in manually read meter routes. Bill due dates are driven by the read date. With AMI, PGE will allow customers to choose their preferred billing cycle, within limits, so that their bill due date is more convenient for them. This is called the Customer Selected Due Date (CSDD) business process.

Existing administrative rules allow PGE, if customers pick their own bill due dates, to advance the date when customers are obligated to pay a late fee by about 30 days. PGE's records show that 76.6% percent of customers pay "on-time," so this change will have no effect on these customers. To determine the expected additional revenue collected from late fees due to this change in business process, an examination of payments that occur after the due date as a function of time was undertaken (see Worksheet 1).

Worksheet 1 explains the additional revenues anticipated from implementing CSDD and also the benefits from "Reduced Working Capital" due to CSDD and remote disconnect and "Saved Power Cost Due to Remote Disconnect.". (In Worksheet 1, "row" will be used to designate a line of information.) Row 1 in Worksheet 1 shows the historical arrears pattern that occurred in 2004. This pattern is applied to the expected revenue in 2007 and then is divided by 12 (in row 4) to show average monthly receipts aged by the amount of delay in payment. Payments at 61-to-90 days in arrears and later are assumed not to be affected by advancing the late pay trigger because these later payments are already subject to a late fee. This amount of delay will be affected by the new remote disconnect process and discussed in the next section.

PGE makes the assumption that about 18% of customers (based on 2004 payment patterns) would incur a late pay fee under the new late pay calculation. PGE assumes that 60% of the customers, row 14, will pay sooner to avoid that late fee, and that 40% of the customers, row 15 will not pay earlier, and so will incur a late fee. The increase in annual late pay fees ($1.65 million, row 29) is calculated in row 17 multiplying arrears (row 7) by the late fee penalty of 1.7% and by 12 to determine an annual value. The new late fee rule is not implemented until all customers have an AMI meter (mid-2009), so the amount shown in 2010 includes escalation in revenue due to customer growth.

CSDD and Remote Disconnect Reduced Working Capital (Line 19)

Table 6-9

Item	Tab	Cells	Basis
▪ CSDD & Remote Disconnect Reduced Working Capital	O&M Summary	D110	Analysis of PGE's data on customer bill payment and disconnect patterns

Both of PGE's business process changes (CSDD and remote disconnect) advance payments by customers closer to their bill due dates. As discussed in the preceding section, PGE assumes that 60% of the potential late-pay customers affected by CSDD will pay on time to avoid the late fee. This means that PGE's cash flow will improve and this is measured as a reduction in working capital. Row 8 of Worksheet 1 indicates the average number of days payment will occur earlier to avoid the late fee. Row 10 normalizes the earlier days of payment to a one-month impact. Row 11 indicates the reduction in working capital if <u>everyone</u> paid on time; row 16 adjusts this impact to reflect the 60% assumption. This calculation contributes to the total working capital benefit shown in row 28.

With the remote disconnect process, payments also occur earlier, but not because the late fee is applied earlier. Under existing rules, PGE can disconnect customers about 29 days after the bill due date. In current practice, PGE doesn't do so and, as a result, PGE has active accounts in arrears as late as 121-to-150 days. The reasons for this delay include allowance for first time infraction, a relatively small bill, and manpower constraints. With the AMI remote disconnect capability, PGE expects the average disconnect to occur at about 50 days after the bill is due; the number of days payments occur earlier from this practice is shown in row 9 of Worksheet 1. The normalized months of improvement are shown in row 10. If <u>all customers</u> pay when given a 5-day cut-out notice, or just after disconnection, the reduction is working capital is shown on row 12. However, in practice, there are customers that vacate their home without notice rather than pay their bill. In rows 18 and 19, PGE assumes that 83% of customers will pay their bills and that 17% move without payment. Row

20 is the percent of disconnects that occur on homes with the disconnect relay[2]. Row 21 is the indirect gain in benefits expected at locations without remote disconnects to keep them somewhat consistent with days for those with disconnects. Row 22 calculates the working capital on row 12 reduced for the 83% assumption and the adjustment for meters without disconnects; these totals are shown again on row 28. The sum of working capital benefits on row 28 is $10 million. This value is used as input to Attachment B of the working papers filed with PGE's AMI tariff request. The treatment on row 110 of the O&M Summary worksheet in the AMI model is only an approximation.

Remote Disconnects Saved Power Costs (Line 20)

Table 6-10

Item	Tab	Cells	Basis
▪ Saved Power Cost from Remote Disconnect	O&M Assumptions	D127:G130	Earlier disconnects based on historical percent of customers who move away without notice following a disconnect

As discussed above, 13% of customers who have been disconnected move away without notice or payment to PGE. These accounts become inactive and, ultimately, the majority of these balances usually become write-offs. With AMI, the ability to disconnect meters earlier means that power deliveries that would likely have been written off are not delivered. The benefit is determined by calculating the energy represented (row 23) in arrears (row 4), times the 13% (row 19), divided by the average retail rate ($87/MWh). This amount of energy is reduced in rows 24 and 25 for the same factors discussed in the section above. Row 26 calculates the energy not delivered by the ratio of the earlier days of disconnect (row 9) to the total day of arrears (row 6). The dollar benefit in row 27 and 30 is the product of the energy not delivered times the avoided power cost ($65.7/MWh) times twelve to return to an annual benefit.

UFE Reductions (Line 21)

Table 6-11

Item	Tab	Cells	Basis
▪ Unaccounted for Energy (UFE) Reductions	O&M Summary	D112	Conservative application of industry experience

A general survey of industry research suggests the avoidable unaccounted-for-energy (UFE) reduction is in the range of 0.5% and 2% of total sales. The model assumes, conservatively, that an incremental savings of 0.25% can be detected through systematic computer analysis of interval data available on all meters, and by using specialized, temporary AMI metering on service transformers. In 2010, energy sales were estimated at 18.4 million MWh. Avoided power cost for this estimate has not been updated since a 2005 forecast of $40.66/MWh. The benefit in cell G112 of the Summary O&M spreadsheet of $1,871K equals the product of 18,400K MWh * 40.66 $/MWh * 0.25%.

[2] See the basis for this number in the write up for Line 13 Reduced FCR Cost.

A&G Reductions (Line 22)

Table 6-12

Item	Tab	Cells	Basis
▪ Direct Labor Savings	O&M Summary	D61-D13	Net labor savings
▪ A&G Loading Value 8.1%	O&M Assumptions	B104	59% of standard A&G loading based on support departments affected

Administrative and General overhead cost savings are assumed proportional to the reduction in direct labor costs times 8.1%.

Increased kWh (previously unbilled) (Line 23)

Table 6-13

Item	Tab	Cells	Basis
▪ Increased KWh (previously unbilled)	O&M Assumptions	B134:I135	Early detection of move-ins with no notification; assumes 50% of instances with average of 4-day delay

The "Increased kWh Billing" shown in cell B135 on the O&M Assumptions tab is based on detecting customers that move in without notifying PGE in a timely fashion. About 60,000 move-ins occur per year when no one is accountable to pay for energy use. Between occupants, PGE monitors inactive accounts for use, but substantial use can go undetected because the meter is only read monthly. AMI allows PGE to monitor inactive accounts on a daily basis. If 50% of the customers in these 60,000 accounts average a 4-day delay (at 30 kWh/day) to notify PGE before moving in, then PGE will reduced unbilled power by 7,200 MWh/year. The dollar benefit of $202,000/year is calculated using a benefit of $0.028/kWh since the energy loss already is recovered via line loss.

Improved Meter Accuracy (Line 24)

"Improved Meter Accuracy" is based on two effects: replacing slow meters and increased sensitivity on the new meters. The assumptions are summarized below.

Table 6-14

Item	Tab	Cells	Basis
▪ Replacing Slow Meters	O&M Assumptions	B152:C153	OPUC 2003 sample test report
▪ $0.028 per kWh Benefit	O&M Assumptions	B148	Non-energy increased revenue
▪ Increased Meter Sensitivity	O&M Assumptions	B142:B146	OEM spec sheet
▪ Benefit Ramp-In Rate	O&M Assumptions	D140:I141	Meter deployment rate

About 40% of PGE's mechanical meter are more that 20 years old. In the 2003 sample test report, these older meters ran slow by an average amount of 0.14%. About $790 million is collected on all of these meters annually. Since the solid-state meters cannot run slow, this unbilled use will now be collected. The assumed benefit is $0.028/kWh since the energy loss is already recovered via line loss. The calculation of benefit (see cell F153 on the O&M Assumptions tab) is $164,000 per year in 2007.

Solid-state meters also are able to record energy use at a lower wattage level than mechanical meters due to the friction created by the disk's bearing that must be overcome. The estimate for increased measured use because of this sensitivity is 16 kWh per year (O&M spec sheet details: B142-B146) and this applies to 760,000 existing mechanical meters. Using the same benefit basis used above for slow meters, the calculated benefit is $330,000 per year. These two benefits are realized as the new solid-state meters are installed.

Special Meter Costs, TOU Load Research, etc. (Line 25)

Table 6-15

Item	Tab	Cells	Basis
▪ Avoided Capital Installed Cost	CAPEX	J177	Included in Status Quo Capital
▪ Avoided Incremental Read Cost	O&M Summary	D45	Included in Status Quo O&M

Without AMI, PGE must support Direct Access, Load Research, TOU, Demand Response and a failing set of "drive-by" meters installed in 1993 by installing special meters. The Status Quo case includes the capital and O&M expense necessary to support these activities. Since AMI can support these activities, these costs are not shown in the AMI case and, thus, represent a savings due to AMI. In 2010, the quantity of avoided special meters averages 1,000 commercial and residential meters per year. The average avoided cost is $230. By 2010, the cumulative number of meters that are read (either by the existing AMI systems or by meter readers) reaches 18,000 meters, including 15,000 drive-by meters. The quantities of meters in each category are based on input from program managers for these activities. The meter cost and meter reading cost assumptions are based on current practices.

7. Net Capital Revenue Requirements

Table 7-1
(Dollars in 1000s)

Line	Item	Tab	Cells	2007	2008	2009	2010
26	Installed AMI Meters	New Meters-NMR	H139	$118	$4,187	$14,891	$20,226
27	Communication System	Network Comm. Eq-NMR	H126	$0	$802	$1,486	$1,527
28	Information Technology	Computers (servers)-NMR	H126	$394	$3,157	$4,422	$4,388
29	Accelerated Depreciation of Old Meters	OldMeters-NMR	I38 + I43	$11,093	$14,299	$10,457	$0
30	Status Quo Revenue Requirement of: Old Meters, New Meters, Vehicles, Handhelds	OldMeters-SQ NewMeters-SQ NewVehicles-SQ Handhelds-SQ	I43 H136 H136 H126	($7,222)	($7,259)	($7,026)	($6,887)
C	**Total of Capital RR**			$4,383	$15,187	$24,229	$19,254
C*	**Total from Attach. A**	Summary	G20:J20	$4,383	$15,187	$24,229	$19,254

Installed AMI Meters, Communication System and IT (Lines 26, 27 & 28)

Table 7-2

Item	Tab	Cells	Basis
▪ Installed AMI Meters	NewMeters-NMR	H139	Standard utility method based on the outcome of UE180
▪ Communication System	Network Comm. Eq-NMR	H126	Standard utility method based on the outcome of UE180
▪ Information Technology	Computers (servers)-NMR	H126	Standard utility method based on the outcome of UE180

The references in Lines 26, 27 and 28 of Table 7-1 show the specific cell containing the values for the revenue requirements for capital expenditures. The sum of all AMI capital-related revenue requirements for 2007 appears in cell G14 of the Summary tab.

In each case, the tab of the cell referenced is the spreadsheet dedicated to calculating the revenue requirements based on standard utility methods. For each of the three categories of capital there is a corresponding tab to account for the differences in tax and book treatment. The assumptions for all of these calculations are based on the outcome of UE180. The common variables are listed in rows 8 through 17 in the Capital Assumptions tab.

Assumption of Accelerated Depreciations of Existing Meters (Line 29)

Table 7-3

Item	Tab	Cells	Basis
▪ Accelerated Depreciation of Old Meters	OldMeters-NMR	I38 + I43	Meter exchange rate used in the model

The tab "OldMeter-SQ" calculates the revenue requirement to depreciate and remove all existing meters from PGE's books. The result is found as the sum of rows 38 and 43 in this tab. The basis matched the deployment rate in the model. Attachment B of the PGE tariff filing refines this method to account for meter assets that will not be subject to accelerated depreciation, and shifts the recovery earlier to levelize the revenue requirements and ensure that there is no Ballot Measure 9 issue. Attachment B is explained in detail below.

Status Quo Revenue Requirement (Line 30)

Table 7-4

Item	Tab	Cells	Basis
▪ Status Quo Revenue Requirement of Old Meters, New Meters, Vehicles, Handhelds	OldMeters-SQ NewMeters-SQ NewVehicles-SQ Handhelds-SQ	I43 H136 H136 H126	Standard utility depreciation methods

In the full AMI model, the Status Quo capital revenue requirements, Summary tab, row 7, contains seven contributors to the revenue requirement. Four of them are shown in Table 7-4 above.

Computers and Network equipment are zero contributors in the Status Quo case. Old Vehicles in the Status Quo case is a non-zero contributor but cancels with an equivalent amount in the AMI case, as explained in the next section.

The four meaningful contributors in the Status Quo case are (1) Old Meters, meaning those purchased through the end of 2006, (2) New Meters deployed in 2007 and after, (3) New Vehicles to replace worn-out vehicles used by meter readers and FCRs on a 10-year replacement cycle, and (4) New Handhelds. New Handhelds are included because the handheld meter reading devices used by meter readers today have reached their useful end-of-life, are no longer supported by the manufacturer and are due for replacement. If AMI does not go forward, they will be replaced as indicated in the Status Quo case.

Explanation of Line C

Line C of Table 7-1 is the sum of Lines 26, 27, 28, 29 & 30. With two omissions explained below, lines 26 through 29 equal the sum to be found in the total AMI capital revenue requirement in row 14 on the Summary tab. Not shown in the 1-page model (Worksheet 2) are two additional contributors that exist in the formula for cell G14, and subsequently in G20 in the Summary tab. The first omission is the revenue requirement of new vehicles in the AMI case. Since PGE has more than enough new vehicles at the start of this project, the replacement vehicles to be purchased in 2015 for field employees (FTEs) do not show up in the model until 2016. The second omission is the revenue requirement for existing vehicles in the AMI case; these are shown on the tab OldVehicles-NMR. These are the same calculations shown in OldVehicles-SQ[3]. The assumption that allows for this equality is that vehicles now in service will either remain in service for other PGE field workers or that they will be sold at what is assumed to be book value. In most cases, the older vehicles will be sold at a small loss to PGE relative to book value.

Including Line 30 in the total of Line C effectively subtracts row 7 from row 14 shown in the Summary Tab of the full AMI model. This difference is shown in row 20. Row 20 is copied into line C*. Line C equals C*. That indicates that all capital assumptions are correctly shown in the 1-page model shown in Worksheet 2.

8. Reconciliation of Simplified Model with Full AMI Model

Table 8-1
(Dollars in 1000s)

Line	Item	Tab	Cells	2007	2008	2009	2010
I	Sum of Capital and Net Benefits	from above	Sum C + N	$3,925	$13,319	$13,911	$2,822
II	Row 21 of AMI Model	Summary	G21	$3,968	$13,425	$14,143	$2,867
III	Difference			$43	$106	$232	$45

[3] Since the project NPV is based on taking the difference of these two equal calculations, both can be ignored.

Worksheet 2, the "1-page" model, shows the line numbers listed above on a single page. The net incremental revenue requirements shown above and in the 1-Page model as Line I. Row 21 in Attachment A on the "Summary" spreadsheet is copied into Line II.

The project period covers years 2007 through 2009. 2010 is the first full year of operations after the project period ends. In almost all instances, years 2011 through 2023 use the same formulas used in 2010 to account for meter growth and escalation of labor and other costs. Significantly, meter prices do not escalate since meters, as with all electronics, have shown a steady or slowly declining nominal price trend for more than 20 years.

The difference between these models (Line III of Table 8-1) is due to the simplified treatment of labor costs used in this document to simplify the explanation of what is being calculated with more detail in the full AMI model.

CERTIFICATE OF SERVICE

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I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-13-0070, to the following parties or attorneys of parties.

Dated at Salem, Oregon, this 15th day of September, 2008.

Kay Barnes

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