PGE

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October 25, 2006

Via Electronic Filing and Messenger

Oregon Public Utility Commission
550 Capitol Street NE
Salem, OR 97301-2551

RE: UE 180, 181 and 184

Attention Filing Center:

Enclosed for filing on behalf of Portland General Electric Company in the captioned dockets are original and five copies of:

PGE Sursurrebuttal Testimony and Exhibits of:

- **Pamela G. Lesh – PGE/2400 (NVPC Regulatory Framework);**
- **Jim Lobdell – PGE/2500 (NVPC Port Westward & Biglow Canyon);**
- **Jay Tinker, Stephen Schue, Ted Drennan – PGE/2600 (NVPC Technical);**
- **Patrick G. Hager, William Valach – PGE/2700 (Cost of Capital);**
- **Thomas Zepp – PGE/2800 (Cost of Capital – Review);**
- **Doug Kuns, Marc Cody –PGE/2900 (Pricing); and**
- **Bruce Carpenter and L. Alex Tooman – PGE/3000 (AMI).**

Also enclosed are three copies of:

- **Work Papers (PGE/2600). Work Papers 1-4 are confidential and subject to Protective Order 06-111.**

These documents are being filed electronically. Hard Copies will be sent via messenger.

An extra copy of this letter is enclosed. Please date stamp the extra copy and return to me in the envelope provided.

Sincerely,

DOUGLAS C. TINGEY

DCT:jbf
Enclosures
cc: Service List -via US Mail – (with testimony only).

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the following: **SURSURREBUTTAL TESTIMONY AND EXHIBITS OF PORTLAND GENERAL ELECTRIC: PAMELA G. LESH –PGE/2400 (NVPC REGULATORY FRAMEWORK); JIM LOBDELL- PGE/2500 (NVPC PORT WESTWARD & BIGLOW CANYON); JAY TINKER, STEPHEN SCHUE AND TED DRENNAN – PGE/2600 (NVPC TECHNICAL); PATRICK G. HAGER AND WILLIAM VALACH- PGE/2700 (COST OF CAPITAL); THOMAS ZEPP – PGE/2800 (COST OF CAPITAL-REVIEW); DOUG KUNS AND MARC CODY- PGE/2900 (PRICING); BRUCE CARPENTER AND L. ALEX TOOMAN – PGE/3000 (AMI)** to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service.

Dated at Portland, Oregon, this 25th day of October 2006.

DOUGLAS C. TINGEY

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Table of Contents

I. Introduction

Q. Please state your name and position at PGE?

A. My name is Pamela G. Lesh and my position is Vice-President, Regulatory Affairs and Strategic Planning. I am responsible for all aspects of regulatory affairs and for overall strategic planning at PGE. My qualifications previously appeared in PGE Exhibit 100.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the positions various parties take in their rebuttal testimony with respect to net variable power cost (NVPC) regulatory framework issues.

Q. How is your testimony organized?

A. My sursurrebuttal testimony has three sections after this introduction. In Section II, I discuss issues related to power cost adjustment (PCA) mechanisms. These include arguments the other parties raise as considerations in the adoption of a regulatory framework for PGE's power costs and the reasons why PGE urges the Commission not to include a deadband in such a framework for PGE. Should the Commission conclude, however, that the power cost regulatory framework must include a deadband, I provide parameters for making this as fair as possible to PGE and customers.

In Section III, I discuss the advantages of an Annual Update tariff in achieving the most accurate NVPC forecast possible.

In Section IV, I conclude that:

- PGE needs a PCA mechanism that is consistent with its obligation to provide on-demand electricity at cost-of-service rates, its capital structure, and its authorized return on common equity.

- PGE does not propose to change the current MONET model-based methodology for establishing the NVPC forecast, although we are willing to explore the possible use of historical costs suggested by ICNU.
- The power cost regulatory framework that PGE proposes is most like those used for similar, vertically integrated electric utilities with which PGE must compete for capital.

II. Deadbands and PCA Mechanisms

Q. What is the purpose of this section of your testimony?

A. In this section, I discuss various arguments the parties raise regarding how the Commission should design a regulatory framework for PGE's power costs and why PGE believes deadbands should not have a place in the framework. I also present information on the consequences of an earnings test deadband. Finally, I describe ways the Commission could include a deadband within a regulatory framework for power costs with the fewest possible concerns and unintended consequences.

Q. Does the surrebuttal testimony the other parties offer help clarify the central issue regarding a regulatory framework for PGE's power costs?

A. Yes. Despite Staff's assertion to the contrary, we do "grasp the fact that both shareholders and customers want to avoid the same thing: exposure to large increases in NVPC." (Staff/1500, Galbraith/8). No one <u>wants</u> these hard-to-forecast costs of hydro and thermal coal plant production variations which, since the turn of the century, have become much more costly (less than planned production) or more valuable (more than planned production).

We understand that the sudden price increases and availability concerns of 2000/01 shocked our customers and created an anxiety about energy that has not dissipated; even as electricity markets have somewhat stabilized, natural gas and refined crude oil price increases continue to cause discomfort. After over almost 15 years of declining real prices for electricity, 2001 was an unpleasant surprise for both PGE and our customers. The 1990s, with a nascent wholesale market awash in surplus power and abundant natural gas at record low prices, were over.

The first years of this decade and century marked the change. CUB's table (CUB/300, Jenks-Brown/7) is instructive, but we have reproduced it below to show the costs that have been absorbed by PGE. Table 1 below shows that while the Commission has recently engaged in annual resetting of prices for power costs on a forward looking basis (*i.e.*, the RVMs), those price changes have left PGE with a significant amount of forecast to actual power cost variances to absorb.

Table 1
Effects of Power Cost Variations

Docket/ Year	Name	Effect on PGE Pric	Variance impact on PGE Earnings
UM 1039	2001/02 PCA	Increase $37M	Decrease $43.8M
UE 139/ 2003	2003 RVM	Decrease $172.8M	Decrease $28.6M**
UE 149/ 2004	2004 RVM	Increase $17.2M	Increase $3.5M**
UE 161/ 2005	2005 RVM	Increase $27.5M	Decrease $32.3M**
UE 172/ 2006	2006 RVM	Increase $102.4M	NA

* We corrected CUB's numbers to show the effect on customer prices, rather than the year-to-year change in NVPC, which does not adjust for changes in cost of service load.

** This uses Staff's formula for calculating the variance between forecasted and actual NVPC. Because the Commission has not yet acted on PGE's request to defer the costs associated with a portion of the Boardman outage, we did not reflect that above.

The electricity-related events of these last six years have not been easy for either PGE or our customers. These events flow from the resource portfolio we presently manage to provide our customers with on-demand retail electricity service. Most of the long-term resources in this portfolio – the ones that have inherent within them unexpected cost volatility – date back long before this time and are PGE's lowest-cost resources. The volatility is an unintended consequence – reflecting the difference between these resources' low costs and current high market prices – but not an irremediable one. With thoughtful, cautious additions to or changes in our resource portfolio, the volatility could decline. Its decline would not be without trade-offs, however. We are willing to explore this with the Commission and our customers. It makes sense to do so in the forum devoted to analyzing - quantitatively and qualitatively – our resource portfolio and choices: Integrated Resource Planning.

Until the Commission approves or acknowledges changes or additions to PGE's resource portfolio, however, the costs of those resources – forecasted or not – are the costs we incur. PGE included in this filing a comprehensive regulatory framework for connecting PGE's prudently incurred power costs to our cost-of-service rates for on-demand retail electricity service. The difficulty of forecasting some of these prudently incurred costs does not mean that the Commission can liberally exclude them from ratemaking. Despite Staff's assertion, we have not said that the Commission does not have the "ability to allocate the risk of exposure to large increases in NVPC." (Staff/1500, Galbraith/10). The disagreement is about the principles the Commission should follow in doing this.

Q. Is the assertion that no one wants these costs helpful to the Commission in deciding how to allocate the risk that actual NVPC will differ from those forecasted in a test year?

A. No. It is not helpful to argue that no one <u>wants</u> these costs. As I discuss below, it also is not particularly helpful to label the costs as "major," or "extreme," or "unusual." Nor does it help much to argue about what is normal business risk.

Q. Is asserting that customers care less about the possibility of lower power costs than the possibility of higher power costs helpful in deciding how to allocate the risks that actual NVPC will differ from those forecasted in a test year? (Staff/1500, Galbraith/7).

A. No, even if it were true. Staff offers this belief without any evidence, in much the same way as Staff offered its opinion in UM 995 that 250 basis points quantifies the amount of cost change that has to happen before a utility or the Commission will seek to open a general rate case. Good reason exists to doubt the factual basis of this claim.

Indeed, all of the other parties appear willing to assume away customers' interest in cost-of-service outcomes lower than what was forecasted. See Staff/1500, Galbraith/7; CUB/300, Jenks-Brown/2 ("Only if the power cost variance is large enough to warrant deferred accounting, may the Company burden customers with those variations"). While the term "variations" is neutral, the difficulty of considering a price decrease associated with lower-than-forecasted NVPC a "burden" indicates CUB is dismissing this possibility. (ICNU/108, Falkenberg/3, l. 6-8). ("The risk that I have been addressing in my testimony is the risk to customers of additional rate increases that PGE likely would be granted if a PCAM were adopted"). One could conclude from this that the parties would support a regulatory framework in which the Commission simply increased the NVPC forecast to cover any possible un-forecasted increases, but we doubt this is the case.

Assuming away the possibility of un-forecasted NVPC outcomes that are lower does not eliminate the need to establish a comprehensive regulatory framework for power costs that fairly allocates the risks between, and reduces the risks of, customers and PGE's investors. While it is understandable, given recent experience, to focus on the risk of higher-than-forecast NVPC, the risks in fact go both ways. The relevant standard is not what customers "want" but the "prudently incurred cost" PGE incurs to provide the power that customers actually <u>use</u>.

Q. Is the assumption that customers care less about cost decreases the basis most of the parties use in dismissing the cost-of-service risk framework you presented in PGE Exhibit 1800?

A. Yes, at least Staff and CUB. See Staff/1500, Galbraith/8; CUB/300, Jenks-Brown/3, 21; ICNU/108, Falkenberg/3. The alternative proposals that Staff and CUB offer, however, do not treat lower-than-forecasted NVPC as a non-event. Both provide for customer participation in these variances; CUB's proposal does so using an asymmetric deadband that provides customers the (beneficial) financial outcome of realizing this customer cost-of-service risk sooner than PGE would receive the (beneficial) outcome of realizing our utility cost-of-service risk.

ICNU attempts to dismiss cost-of-service risk by asserting that the "risks are equal in sign and always sum to zero." ICNU offers no support for this assertion and it is unlikely given the drivers of the risk: forecast uncertainty and degree of utility control. Assuming the sides sum to zero also assumes that the point forecast chosen for test year ratemaking exactly splits the range of the risk. See PGE Exhibit 1800, Section II. ICNU is correct that using only actual costs in ratemaking would eliminate this risk; whether to do so is Commission judgment. The data response ICNU attaches as ICNU Exhibit 109, explained (in full) that:

> "Although instances of a commission reaching such a conclusion [to reconcile all of the forecasted costs used to set a utility's prices for actual costs] have occurred in the past, it is unlikely that a commission would conclude that using only actual costs best meets the statutory and constitutional requirements and further regulatory goals. As explained in PGE Exhibits 400, 401, and 1800, it is common for commission to conclude that using actual purchased gas costs and net variable power costs (either 100% or subject to some amount of sharing) does meet statutory and constitutional standards and further regulatory goals. Inclusion of actual non-fuel/power operations and maintenance costs is rare,

> although it does occur on selective items, such as energy efficiency program costs as mentioned in PGE's response to ICNU Data Request No. 188."

Q. Does a claim that NVPC variances will more often be higher, than lower, help the Commission decide how to address the cost-of-service risk that actual NVPC will differ from those forecasted in a test year?

A. Yes. Staff expresses its belief that PGE's current set of resources has a greater probability of producing power at higher than forecasted costs than lower than forecasted costs (Staff/1500, Galbraith/7). Staff's assertion may or may not be correct. No one knows what PGE's actual future NVPC will be or how those will differ from what is forecasted from time to time in a general rate case or an Annual Update procedure. If Staff is correct, however, this claim suggests to us that the Commission must significantly reduce this unevenly allocated cost-of-service risk so that PGE's investors have a reasonable opportunity to recover the cost of capital provided PGE for investment in utility service.

Staff, on the other hand, appears to rely on this conclusion to support its argument that the Commission must adopt a large deadband that will, systemically, preclude PGE from recovering the net variable power costs it is incurring to provide on-demand retail electricity service. Otherwise, Staff states, PGE will shift this risk of not recovering the costs incurred in providing service to customers. (Staff/1500, Galbraith/11).

A conclusion that the basis on which the Commission sets PGE's test year NVPC forecast does not evenly allocate the inherent cost-of-service risk, whether true or not, provides no support for a determination that customers need not pay these prudently incurred costs. Again, these are the costs of our resources, unless and until changed pursuant to Commission acknowledgement of a future IRP.

Q. Is there any aspect of a comprehensive regulatory framework for PGE's power costs on which the parties agree?

A. Yes. We agree with Staff's observation that, "The objective should be to avoid allocating cost-of-service risk between shareholders and customers in an uneven manner and to achieve a permanent and fair allocation of power cost risk between shareholders and customers." (Staff/1500, Galbraith/10). We also agree with CUB that it has a history of support for proposals it believes are reasonable to adjust rates for differences between forecasted power costs and actual power costs. (CUB/300, Jenks-Brown/8, l. 5-6). Where the disagreement lies is with the parameters of what is fair and what is reasonable.

Q. Does ICNU assert that perhaps PGE's disagreement is with the recent direction of Commission policy, not with the other parties? (ICNU/108, Falkenberg/3).

A. Yes, and ICNU may be correct. Certainly PGE and the other parties have expressed different views of the application of recent Commission decisions on power cost related topics.

Q. What articulation of the recent direction of Commission policy do the other parties provide?

A. The other parties present the recent direction of Commission policy as follows:

- The Commission will allow coverage of power costs that are higher than forecast only if they are "major increases" or "extreme increases." (Staff/1500, Galbraith/3). This ensures that utilities bear normal business risk. (CUB/300, Jenks-Brown/13).
- The original measure of major or extreme, and conversely normal business risk, was a financial effect on the utility of at least 250 basis points, with sharing of amounts above that. See UM 995. The basis of this measure was Staff's opinion that 250

basis points was the amount of cost change required to trigger a general rate case filing by a utility or the Commission. (See Galbraith Deposition, PGE Exhibit 1801, pages 6-7).

- Major or extreme cost increases were the precursor to the unusual event standard for power cost adjustment (PCA) mechanisms, announced in Order No. 05-1261 (UE 165). (Staff/1500, Galbraith/3).
  - Order No. 05-1261 indicated $15 million might identify what is an unusual event. (Order No. 05-1261, page 11). To this, the Commission added an earnings test deadband of 100 basis points, such that a utility could recover actual NVPC higher than forecast only to the extent that recovery brought the utility's earnings up to 100 basis points below its last authorized return on common equity and would refund actual NVPC lower than forecast only to the extent that refund brought the utility's earnings down to 100 basis points above its last authorized return on common equity.
  - In this case, Staff interprets Order No. 05-1261 to support a deadband of 150 basis points as identifying what is an unusual event, with 90-10 sharing of variances outside this band. See Staff Exhibit 800. Staff does not indicate whether this recommendation considers the effects of the tax true-up in SB 408 or not. Staff recommends adoption of the UE 165 earnings test.
  - In this case, CUB interprets Order No. 05-1261 to support an asymmetric deadband of 150 basis points on the increased cost side and 75 basis points on the decreased cost side, with a subsequent 50/50 sharing tier and last a 90/10 sharing tier. (CUB/300, Jenks-Brown/27). CUB explained that these

amounts are adjusted for the tax true-up in SB 408. CUB also recommends adoption of the UE 165 earnings test.

Q. If this testimony accurately reflects the recent direction of Commission policy, do you agree with that direction?

A. No. Regardless of whether one supports a "deadband" on power costs (which I will call a "variance calculation deadband") and/or through an earnings test, with the explanation that it identifies "unusual events" or ensures that the utility bears "normal business risk," we urge the Commission to reconsider applying deadbands to a comprehensive regulatory framework for PGE's power costs.

Q. Before explaining your reasons for urging the Commission to reject deadbands as part of a comprehensive regulatory framework for PGE's power costs, do you have information to provide regarding the earnings test deadband?

A. Yes. As we previously noted, Order No. 05-1261 included this concept but neither the parties supporting the stipulation nor the parties opposing the stipulation had testified to it. There was no factual record regarding how it might work. Intuitively, it is clear that the test means that other events, within (*e.g.*, O&M cost savings) or outside of (*e.g.*, weather-driven load changes) PGE's control, can affect whether the PCA mechanism lowers customers' and PGE's NVPC cost-of-service risk, particularly if the earnings test deadband is equal to or larger than the variance calculation deadband. Not intuitive is how the various factors might work in combination and particularly what outcomes might result if PGE attempted to reduce or shift O&M because of adverse events occurring within a given year, as CUB notes that we did in 2002 as a response to the load decreases we experienced that year. (See CUB/300, Jenks-Brown/10).

PGE Exhibit 2602 shows the outcomes of various combinations of O&M savings (this also represents other financial impacts on PGE's earnings opportunity – within or outside of PGE's control), NVPC variances and the earnings test deadband. PGE Exhibit 2602 explains how we analyzed the various possible event combinations. I repeat only the conclusions here:

- If there are no O&M savings, whichever amount (variance calculation or earnings test) is larger will govern the recovery/refund of NVPC variances and determine PGE's earnings opportunity for that year.
- An earnings test deadband asymmetrically handles O&M savings. If a NVPC variance is a substantial refund, and there are O&M savings, customers will essentially receive the benefit of the O&M savings to the extent that the power cost decrease is large enough so that the sum of the power cost decrease and O&M savings is larger than the earnings test deadband. If the NVPC variance is a substantial collection, and there are O&M savings, customers will essentially receive the benefit of the O&M savings to the extent that the net of the collection amount and O&M savings exceeds the earnings test deadband. The NVPC variance and O&M savings combinations are a sum in the case of refunds and a net in the case of collections. The asymmetry occurs because:
    - With a NVPC variance that is a collection, O&M savings offset the variance and pull the net of the two toward or into the earnings test deadband.
    - With a NVPC variance that is a refund, O&M savings add to the variance and push the sum of the two toward or outside the earnings test deadband.

- The entire analysis is complicated by SB 408: will the earnings test deadband apply before or after any refunds or surcharges due because of SB 408?

Q. Why do you urge the Commission to reject deadbands for the PCA portion of a comprehensive regulatory framework for PGE's power costs?

A. We urge the Commission to reject the inclusion of deadbands for the PCA portion of a comprehensive regulatory framework for PGE's power costs for several reasons. This policy direction:

- Increases cost-of-service risk to both PGE and our customers.
- Is a significant departure from Oregon's prior policies with respect to electric utilities and current policies with respect to natural gas utilities.
- Is a significant departure from how other states regulate utilities otherwise comparable to PGE and will reflect negatively on Oregon's regulatory climate and PGE in the national financial markets.
- Is not fair with respect to the different types of costs within a utility's power costs, allowing customers to enjoy the benefits of low embedded fixed costs but shielding them from the full variable costs of the same resources.
- Is not fair across utilities because it ignores how much a given electric utility has invested in generation.
- Skews the regulatory framework for normal business risk.
- May not produce reasonable results over a multiple year period.
- If based on a distinction among "events," does not have a sound factual basis.

I explain these concerns below.

Q. Have you previously explained how a deadband increases cost-of-service risk to both utilities and customers?

A. Yes. I covered this in PGE Exhibit 1800, Section II.

Q. Why do you believe that this policy direction departs from prior Commission policy for electric utilities and current Commission policy for natural gas utilities?

A. Briefly, as addressed elsewhere in our testimony (see PGE Exhibit 1800, page 47, and PGE Exhibit 2600, pages 28-29), Commission policy supported a comprehensive PCA mechanism for PGE from 1979 to 1987. The standard deviation of possible NVPC outcomes at that time was much smaller than it is today, with market-based prices for natural gas and power. This PCA had no earnings test.

Even after the Commission terminated PGE's PCA mechanism, the Commission allowed coverage of higher than forecasted NVPC resulting from circumstances before and after Trojan's premature closure. In the first of these, granted before the decision to close the plant allowed a rapid decrease in fixed O&M, the Commission found that requiring PGE to absorb 10% of the increased NVPC resulting from replacing Trojan's output subjected PGE to "normal" business risk. See Order No. 93-257 (UM 445). This Order has an extensive discussion of the role of earnings tests in connection with deferrals that is not directly on point here because a PCA mechanism is an automatic adjustment clause.

Most on point is the Commission's discussion of the role of an earnings test in its 1999 order on purchased gas cost automatic adjustment clauses. This order explains:

> "[T]he earnings review mechanism should be fair to all parties and efficient to administer. The objective should be simply to determine whether or not an LDC's earnings are excessive prior to passing through prudently incurred gas cost changes in rates. It should not be structured so as to turn each PGA filing into an annual rate case or show cause hearing where the company's

> earnings would be subject to detailed review and adjustment. Indeed, such scrutiny may eliminate any incentive for the company to pursue efficiencies.
>
> A fair approach to an excessive earnings review should begin with an ROE threshold determined to be just and reasonable – not excessive – as a matter of policy." Order No. 99-272 at 9.

Even if the Commission concluded that a PCA mechanism for PGE must differ from the PGAs because of PGE's investment in generation, a deadband on the variance calculation could address that difference. Duplicating or compounding the effects of a variance calculation deadband with an earnings test deadband designed to achieve the same purpose – preclude recovery of some amount of prudently incurred power costs – rather than using the earnings test simply to check for excessive earnings is unnecessary and inconsistent with other Commission policies.

Q. Why do you believe that this policy direction departs significantly from how other states regulate electric utilities comparable to PGE?

A. My conclusions here rest on the comprehensive report National Economic Research Associates (NERA) prepared for us (PGE Exhibit 401). Of course, very few other electric utilities have the amount of hydro electric generation that PGE does. The other parties did not rebut the results of this report, which showed that 100% coverage of differences between forecasted and actual NVPC was a common regulatory practice, and that only a few states required sharing, let alone a deadband. The survey did not include earnings test practices so I cannot draw conclusions about that.

Q. Why would inclusion of deadbands in the Commission's regulatory framework for PGE's power costs reflect negatively on Oregon regulatory climate?

A. Both equity investors and providers of debt capital consider the ability of a utility to recover its prudently incurred power costs a key factor in determining whether the regulatory climate is supportive or punitive. In other words, they focus on the regulatory treatment given the utility's side of the cost-of-service risk.

A deadband applied to power cost recovery is suggestive of a less supportive regulatory climate because it implies that the utility will simply never recover certain costs, irrespective of whether the costs were prudently incurred or not. Recently, S&P[1] changed its outlook on PGE to 'negative' and cited "an uncertain regulatory environment," and "power cost variations that cannot currently be passed through to customers" as concerns. S&P also stated that it could restore PGE's outlook to stable if, among other items, "a sufficiently supportive PCA mechanism is adopted in addition to extension of the RVM." Whether S&P believes that a deadband results in a "sufficiently supportive PCA" has yet to be seen. Because most comparable utilities to PGE pass their actual costs of power and fuel (higher or lower) to customers without a deadband, however, it is difficult to see how the rating agencies would consider such a construct 'supportive'.

Q. Why is this policy direction unfair with respect to the different types of costs within a utility's power costs?

A. Applying deadbands to NVPC variances as part of a regulatory framework for power costs that includes the fixed costs of resources in test year ratemaking at embedded levels allows customers to enjoy the benefits of low embedded costs of particular resources while shielding them from the full variable costs of the same resources. The embedded, fixed costs of PGE's resources are just $16/MWh. This includes the low-priced Mid-C contracts, the significantly-depreciated Boardman, Colstrip, and Beaver generating plants, the newer Coyote Springs plant and the first-year costs of Port Westward. The NVPC associated with

[1] See September 25, 2006, S&P Research Report on Portland General Electric Company. The report has been provided in PGE Exhibit 2705.

these same resources, on a forecasted basis, are $41/MWh and we know that forecast includes a large amount of uncertainty.

Staff presents an estimate that its proposed PCA mechanism would result in customers paying only slightly more than half of variances from forecast, while customers would pay just over 60% of variances which exceed the upper deadband (Staff/1500, Galbraith/15). Given this estimation, Staff's claim that customers currently (or in the future would) pay the "full cost" of PGE's resources, is ironic (Staff/1600, Wordley/6). Staff's proposed PCA mechanism design would ensure that they do not.

Q. If customers can avoid the full costs of PGE's current resources, how can they make wise decisions about consumption?

A. Customers cannot make wise decisions about consumption, particularly around long-term equipment and appliance investments, if they never experience the full costs of PGE's resources. This was our point on rebuttal about price signals. See PGE Exhibit 1800 at 31. We already know that marginal costs exceed embedded costs. A regulatory framework that shields customers from the full costs of the resources used to serve them only exacerbates the problem and is potentially a barrier to the development of competitive markets.

This is not really a temporal problem, as CUB argues (CUB/300, Jenks-Brown/19). (See also Staff/1500, Galbraith/13). Customers will pay the tariff rate for any consumption while that tariff is in effect and will, presumably, make decisions to consume or not based on that. The inclusion of surcharges or credits in the calculation of that or any other tariff rate does not change this near-term consumption decision. A PCA mechanism does not base credits or charges to customers based on past consumption that customers cannot avoid; a PCA mechanism simply affects the calculation of the tariff rate that will apply to future consumption. In addition, if CUB and other parties think it better to reflect the credits and charges from a PCA mechanism more promptly in tariff rates than PGE's process proposal, the Commission could always implement the changes on an interim basis, subject to refund or return to PGE after a prudence review. Finally, if CUB and Staff are concerned about proper price signals, they should support the Annual Update tariff, which ensures that the test year forecast used for cost-of-service prices is as accurate as possible.

Q. Why would this policy direction be unfair across utilities?

A. A "deadband" policy direction that excludes cost variances from cost-of-service ratemaking based on a certain number of basis points of the authorized return on common equity the Commission last found that utility required to attract capital is unfair across utilities because it ignores how much a given electric utility has invested in generation. Only 38% (including Port Westward – 29% without) of PGE's investment in facilities for retail electric service relates to generation; the vast majority of the remainder are for local distribution service. For some utilities, the percentage of generation in the rate base is substantially higher. For example, shares of rate base from generation for Detroit Edison and Arizona Public Service are 47% and 45%, respectively. If PGE acquired future resources in the form of purchased power agreements, the situation would only worsen: our overall earnings opportunity would be hostage to the shrinking amount of investment made years ago in generation.

CUB argues at some length that electric utilities are different from natural gas utilities because the former have "expensive generating resources." If that is the case, it is the investment in those "expensive generating resources" that ought to determine a deadband, not the utility's entire investment. And electric utility's distribution investment is much the same as a natural gas utility's distribution investment.

Q. Why does the use of deadbands within a PCA mechanism skew how the regulatory framework otherwise deals with normal business variation?

A. Deadbands within a PCA mechanism, at least for PGE, skew how the rest of the regulatory framework addresses normal business variation[2] simply because the potential power cost variances produced by our current resource portfolio are so large that they swamp these normal business variations. In other words, whether this is a concern really depends on a given utility's resource portfolio. In this case, PGE's non-power O&M is approximately $330 million.[3] Much of this is for the people necessary to run the facilities we use every day to provide on-demand retail electricity service. Absent some change in the nature of that on-demand retail electricity service, the possibility of avoiding more than a small percentage of these costs on an ongoing basis – as PGE might have to do if several years of drought occurred in a row – is not a real possibility.

Q. Why might this policy direction of excluding "normal business variation" or including only "unusual events" be unreasonable over multiple years?

A. Although history does not tell us much about the distribution or size of power cost variances in the future, it does show us numerous periods in which the variances ran one way for a period of years and then another way for a period of years. Even if it was fair to exclude a significant portion of these costs or savings from ratemaking for one year (such as may occur with a deferral application), a cumulative result of such exclusions over four or five years may be unreasonable. The Commission must consider the indefinite future in

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[2] I am using the term variation because the risks (defined as negative events) lie with both customers and PGE. This normal business variation is the result of cost-of-service risk with respect to the other costs required to provide on-demand retail electricity service. As noted above, generally the regulatory framework does not adjust prices for this variation, leaving PGE with its risk and customers with their risk. The variation will affect PGE's earnings positively or negatively.

[3] Non-power O&M includes customer services, administrative and general costs, and operating and maintenance expenses associated with PGE's system.

choosing policy direction for a regulatory framework that will apply year after year and be able to conclude that the result is fair and reasonable over an extended period, not just one year. For example, the PCA mechanism in place for Puget Sound Energy (PSE) for the four-year period from July 2002 through June 2006 included a cap of $40 million on the amount of power cost variances that PSE would absorb. After reaching that cap, PSE incurred only 1% of variances. PSE appeared to first reach the $40 million cap in December 2003, but this was changed by a disallowance ruling in May 2004. PSE then reached the cap in 2005.

Q. Why do you believe that a policy direction excluding certain power cost variances from ratemaking based on whether those variances relate to "unusual events" has no sound basis?

A. We believe that the "unusual event standard" (Staff/1500, Galbraith/3) has no sound basis for two reasons. First, as "applied" so far, it implies a factual finding that does not exist. What is "unusual" is in the eye of the beholder. We acknowledge this is due in part to a lack of information. Lacking fore-knowledge of the total cost of supplying power to our customers for each year of the next 20, 30, or even 40 years, it is not possible to create the distribution that, statistically, might inform a decision that outcomes within one range are usual and outcomes outside that range are unusual and whether any of the outcomes "balance out" over time. Of course, even if we had such information and could make this calculation, that statistical information would tell us little about whether the regulatory framework should excuse customers from paying the un-forecasted, higher costs or preclude them from receiving the benefits of un-forecasted, lower costs deemed "usual."

Our second concern relates to the first. We do not know the distribution of power cost outcomes, year by year, into the future. We have no basis for a conclusion that the past is indicative of the distribution, either of events or – of greater importance – the financial effect of those events. This is the case with all three of the major sources of forecast-to-actual variance PGE's resource portfolio is likely to experience: hydro production, low-cost thermal production, and market-based gas and electricity prices. And while we do not know (beyond the IRP Final Action Plan filed in 2004) what resources PGE will add to this portfolio, we do know that certain resources currently part of the portfolio will not be there in future years as contracts expire and plants retire.

Q. Do you have a recommendation regarding what the Commission should do if it decides to retain a policy direction that includes deadbands in the PCA mechanism in a comprehensive regulatory framework for power costs?

A. Yes. We acknowledge CUB's criticism that "PGE offers no other way – reasonable or not – to identify whether an event is unusual." (CUB/300, Jenks-Brown/17, l. 23-24).

We suggest that, if the Commission believes it necessary, the Commission choose a NVPC variance deadband by combining the following parameters:

- PGE's test year generation rate base;
- A portion of the "risk premium" associated with the required return on common equity found by the Commission for the test year;
- Adjusted for the sharing percentage the Commission adopts for variances outside of the deadband; and
- Adjusted for SB 408, unless and until legislative action removes the "double whammy."

Using only the generation rate base avoids two of the issues I described above. It fairly distinguishes among various electric and natural gas utilities inside Oregon and it ensures that PGE's investment in distribution does not, by itself, cause the deadband to increase. No one could argue that PGE had an incentive to invest in generation simply to lessen the effect of the deadband on necessary new distribution investment.

Limiting the NVPC variance deadband to a portion of the risk premium (over the market cost of debt) associated with the required return on common equity for this generation investment also makes more sense than an arbitrary number, such as 250 basis points. It is for this risk premium that equity investors' claims to the assets of the utility are subordinate to providers of debt capital. Under Staff's ROE proposal of 9.40% (Staff/1400, Morgan/2), the risk premium is only 316 basis points.[4] 250 basis points would consume nearly all of this. Even under PGE's recommendation of a 10.75% ROE, the risk premium is only 451 basis points. Other business risks apply to generation, including but not limited to load risk, cost-of-service risk for O&M and capital additions, and "ORS 757.355" risk. This last risk has existed for many years in the form of requiring total disallowance of any plant investment in a facility that does not, ultimately, reach commercial operation. Some suggest that Oregon utilities can be held liable in civil actions for rates found to include any return on such investments, regardless whether the Commission has found the rates just and reasonable under statutory and constitutional standards. The Commission should not adopt a NVPC variance deadband that consumes the entire risk premium for PGE's side of the NVPC cost-of-service risk.

[4] PGE estimates the market cost of new debt at 6.24%, based on estimates of new debt placements described in the work papers to PGE Exhibit 2700.

The choice of the amount of risk premium to subject to cost-of-service risk should consider any sharing percentage applied to amounts beyond the deadband. In determining whether PGE's side of the cost-of-service risk affected by the PCA mechanism is fair to investors, the Commission should consider the combined effect of the deadband and sharing percentage. Notwithstanding the other parties' complaints that 10% is small (see CUB/300, Jenks-Brown/10, Staff/800, Galbraith/16, and ICNU/103, Falkenberg/37), it will significantly affect PGE's opportunity to earn the return our investors require for providing capital to the business. Considering the two aspects, we propose that 50% of the risk premium is a reasonable NVPC deadband when combined with 90/10 sharing of variances outside the deadband.

Last, until future legislative action changes SB 408, any PCA mechanism designs must consider the effects of the tax true-up on customers' and utilities' cost-of-service risk. Prior to SB 408, income taxes mitigated cost-of-service risk for both customers and utilities; now, they do not. Decreases from forecasted test year cost to actual cost trigger surcharges to customers; increases trigger refunds. Whatever amount of NVPC cost-of-service risk the Commission would otherwise find reasonable to leave with customers and PGE, it should reduce this to offset the double whammy effect of SB 408. We appreciate CUB's recognition of this in adjusting their recommendation for a PCA mechanism.

With respect to an earnings test deadband, we suggest that the Commission apply the policy direction articulated in 1999 for PGA automatic adjustment clauses, such that the earnings test precludes only excessive earnings rather than act as a duplicate deadband on the power cost variances the PCA mechanism includes in prices for both customers and PGE.

If the Commission does not apply this policy direction and finds it necessary to add an earnings test deadband to the variance calculation deadband, it should choose an earnings test deadband smaller than the variance calculation deadband and, ideally, such that PGE would recover additional actual costs up to some number of basis points above our authorized return on common equity and return lower costs down to some number of basis points below our authorized return on equity. This will preserve much of how the regulatory framework handles cost-of-service risk on all of the other costs that comprise PGE's provision of on-demand retail electricity service. In other words, at least within a reasonable range, even if normal business variation has resulted in PGE earning less than its authorized return on common equity, customers should still receive a NVPC variation that results in a refund and even if normal business variation has resulted in PGE earning more than its authorized return on common equity, PGE should still receive a NVPC variation that results in a collection. A reasonable range might be expressed by the range of possible returns on common equity the Commission found reasonable when it chose the point estimate authorized in the last rate case. Typically, this range is no more than 50 basis points above or below the point estimate chosen. Thus, the PCA mechanism refunds would occur unless refunding more would result in utility earnings less than 50 basis points below the authorized return on common equity and allow collections unless collecting more would result in utility earnings more than 50 basis points above the authorized return on common equity.

PGE Exhibit 2602 and the discussion on pages 11-13 demonstrate the possible unintended effects on O&M savings of the earnings test proposed by other parties. PGE Exhibit 2603 demonstrates that the "refund down to 50 basis points below authorized ROE and collection up to 50 basis points above authorized ROE" structure would largely alleviate the possible unintended effects on O&M savings.

Q. CUB states that PGE has supported the inclusion of a deadband in a PCA mechanism for five years and wonders why PGE has changed its position in this case. (CUB/300, Jenks-Brown/24-26). Can you explain?

A. First, I think the word "support" is too strong in this instance. We <u>settled</u> on a deadband – in UM 1008/1009, UE 115, and UE 165. We filed a tariff to extend the UE 115 PCA mechanism, which expired at the end of 2002 that simply adjusted the stipulated deadband to a 12-month number, rather than the 15-month number in UE 115 and maintained the energy revenues portion of the formula. We withdrew this tariff when it became clear that the other parties would support only significantly higher deadbands. We did not "support" the result in UM 1071. We did include a deadband in the Hydro Adjustment Tariff in UE 165, of a size we thought fair and reasonable: $2.5 million on either side of forecast. Although we think the better regulatory policy is simply to apply a sharing percentage to the variances, the UE 165 proposal was not unreasonable to us.

Second, the better question is what has changed since some of these filings? Gas prices took a steep rise. Although the rise has temporarily abated, no one is forecasting gas prices of the levels last seen in 2002 and 2003. The level of gas prices significantly affects the financial impact of changes in hydro and thermal coal plant production. In other words, at gas prices in their current range, the size of cost-of-service risk is much larger than with gas prices half as high. In addition, although 2006 finally produced normal to slightly above normal hydro conditions, five out of the last six have been poor to very poor. The concern we raised in 2004 with our UE 165 filing that the historical water years used to forecast hydro might no longer be "normal" has only deepened with time. What will normal water be? Another thing that changed was our knowledge of regulatory frameworks in place for utilities comparable to PGE. It was not until the summer of 2005 that we asked NERA to study the matter for us, with sufficient detail to permit comparisons. As NERA completed this study, we discovered just how different Oregon's approach was. Last, as it becomes clear that PGE's customers will require a significant amount of new resources, we have become increasingly concerned that we understand the rules of the game. With respect to a comprehensive regulatory framework for PGE's power costs, we need answers to questions such as:

- Will a required deadband mean that we should prefer new generation investment over power purchase agreements so that NVPC variances left with PGE compromise less of our return on transmission and distribution investment?
- Will a required deadband increase the cost-of-service risk of owned wind generation over wind acquired through a power purchase agreement because of the low variable cost of wind compared to market prices?

All of the above considerations, along with the reasons I described above why we believe that a deadband of the size the parties recommend is unfair and unreasonable, led to our proposal of a simple PCA mechanism in the comprehensive regulatory framework for power costs we filed in this docket.

III. Annual Update Tariff

Q. What is the purpose of this section of your testimony?

A. In this section, I focus on the advantages of PGE's proposed Annual Update tariff for producing the most accurate NVPC forecasts possible.

Q. Do the other parties continue to oppose PGE's proposed Annual Update Tariff?

A. Yes. Staff and CUB continue to argue that basing cost-of-service rates on the most recent information is not worth the regulatory burden (Staff/1500, Galbraith/2; CUB/300, Jenks-Brown/28); CUB also argues that an annual update shifts risk from PGE to our customers. (CUB/300, Jenks-Brown/28).

Q. What is the primary cause of NVPC variation that an Annual Update addresses?

A. PGE's proposed Annual Update ensures that our cost-of-service prices reflect the prices of the actual purchased power and fuel contracts we have entered into to serve customers over a given year. These are market prices and, for the past several years, quite volatile. The table CUB presents in its testimony, replicated on page 4 of this testimony, shows this recent volatility, including a one-year drop of over $172 million from 2002 to 2003 and a one year rise of over $102 million from 2005 to 2006. We believe that, if the efforts of PGE, Staff and any intervenors that choose to participate will result in better ratemaking for PGE's customers, we collectively have the obligation to put forth that effort.

Q. Are the causes of year-to-year NVPC variance different from those of within-the-year NVPC variances?

A. Yes. Although fuel and power market price volatility can affect within-the-year NVPC variances, addressed by a PCA mechanism, the greatest effect of these variances on NVPC cost-of-service risk is year-to-year, not within the year. Within-the-year it is hydro and coal plant production, combined with gas and power market prices, which produce the variances.

Although both types of variances result from forecasting uncertainty, it is much easier to improve forecasting certainty for fuel and power contracts than for hydro and thermal plant production. The contracts become certain once entered into; hydro and thermal plant production do not become certain until actually experienced.

It is unpredictable how the year-to-year market price variations interact with the within-the-year plant production variations. Some years they may work to offset each other; other years, they may exacerbate each other.

Q. Does PGE still propose that the Commission adopt the Annual Update Tariff?

A. Yes. As explained in PGE Exhibit 1800, it reduces the size of NVPC cost-of-service risk by using known, current information in the test year forecast and it helps the Commission maintain the allocation of NVPC risk it has chosen in creating the test year forecast. (PGE Exhibit 1800 at 33). Arguing that it is not worth the regulatory burden to minimize cost-of-service risk by including within our cost-of-service prices the most accurate information we have is disconcerting. Moreover, without the Annual Update tariff, PGE is likely to file general rate cases more frequently, at least when the cost of our market fuel and power purchases is rising. General rate cases impose much greater regulatory burden than the Annual Update process PGE proposed.

That being said, however, we would prefer that the Commission reject this tariff rather than use its presence as the basis to include a larger NVPC variance or earnings test deadband in the Annual Variance Tariff. This is because we have some ability to manage the timing of our market fuel and power purchases such that we can reflect these in test year ratemaking processes; we have no ability to ensure that test year ratemaking accurately reflects the hydro or coal plant production we experience in any given year.

IV. Conclusions

Q. What are your conclusions about a regulatory framework for PGE's power costs at this point in the proceeding?

A. My conclusions are:

- Cost-of-service risk exists and is the risk that the Commission is addressing when it designs a regulatory framework for PGE's power costs. The other parties rebut this only by assuming away the customer side of cost-of-service risk. Some of the arguments the other parties advance suggest that PGE does something other than provide on-demand retail electricity service at cost-of-service rates. They imply we should be like a brokerage house, gambling that natural and market circumstances will cause NVPC to fall in some years, providing profits that are larger than unexpected increases in NVPC (Staff/1500, Galbraith/6); or that we are an insurance company, charging customers premiums that protect them against unexpected NVPC. (CUB/300, Jenks-Brown/3, l. 9-10). Other arguments imply that customers are providing us insurance against the costs we must incur to provide the power they are using at any given moment. (Staff/1500, Galbraith/11). PGE is not a brokerage house, insurance company or insurance customer. PGE is simply a retail electric utility and this case concerns the regulatory framework under which PGE will provide that service at cost-of-service prices. If the other parties wish the Commission to construct a regulatory framework that treats us like a brokerage house or insurance company, the Commission must choose an authorized return on common equity and capital structure that reflect this.

- How PGE forecasts NVPC already allocates more cost-of-service risk to PGE than to customers and the other parties would exacerbate this by imputing "extrinsic value" of some amount. (See PGE Exhibit 2600). We oppose this imputation even if the Commission adopts our Annual Variance Tariff as proposed, but it is even more egregious if the Commission includes deadbands in the PCA mechanism portion of the power cost regulatory framework.
- For all of the reasons stated in PGE Exhibits 1800, 1900 and 2600, PGE does not propose to change how we develop a forecast of NVPC. MONET is a good representation of what we know and does as good a job with uncertainty as one can expect. Stochastic modeling would significantly compound forecast uncertainty without eliminating any cost-of-service risk. ICNU's suggestion that we use non-normalized historical costs to create a forecast test year is intriguing but we don't understand it well. We are willing to explore this concept with the other parties for purposes of future test year NVPC forecasts. Adopting historical costs as the basis of forecasting, however, would not remove the need for a PCA mechanism.
- The power cost regulatory framework PGE proposes is most like those used for similar, vertically integrated electric utilities. Including a variance calculation deadband weakens this similarity but is acceptable if the Commission develops the deadband using the parameters I discussed in Section II. Any earnings test deadband should also use the parameters discussed in Section II.

Q. Does this conclude your testimony?

A. Yes.

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I. Introduction

Q. Please state your name and position at PGE.

A. My name is Jim Lobdell, and my position is Vice-President, Power Operations and Resource Strategy. I am responsible for the development and operation of all of PGE's power supply resources. My qualifications are at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut CUB's statements concerning the prudence of Port Westward. I also provide information on progress to date for the Biglow Canyon Phase I development. Finally, I rebut other parties' assertions that PGE simply dispatches its plants to market and explain how PGE's financial condition affects PGE's power supply activities.

Q. How is your testimony organized?

A. This introduction is Section I. In Section II, I discuss Port Westward and the Biglow Canyon Phase I development and their interaction as parts of PGE's Commission-acknowledged 2002 IRP Final Action Plan. In Section III, I discuss how PGE's obligation to serve its customers' loads and maintenance of required reserve margins are very important considerations in PGE's dispatch decisions. I also discuss how PGE's financial condition impacts its ability to provide power for customers.

II. Port Westward Considerations

Q. What is CUB's general concern regarding the prudence of PGE's acquisition of Port Westward?

A. CUB expresses "concern that PGE has not sufficiently made the case that the inclusion of Port Westward is prudent in light of other actions taken consistent with PGE's most recent acknowledged IRP." (CUB/300, Jenks-Brown/29). In addition, CUB states that "PGE has not provided any evidence in the record that it has acquired or will acquire the resources included in the Company's IRP action plan." (CUB/300, Jenks-Brown/29). CUB is particularly concerned with PGE's acquisition of the wind resources included in the 2002 IRP Final Action Plan.

Q. Is this a valid general concern?

A. Yes. The Commission acknowledges an overall action plan, which is a "package" of resource acquisitions. It is important that a utility complete all major elements of an action plan, unless conditions change substantially. If conditions do change significantly from those assumed in the IRP, then the utility's continuing prudence obligation requires that it address these changes.

Q. Is CUB's general concern well-founded here?

A. No. CUB is concerned that PGE wants the Commission to recognize in its order in this docket that PGE prudently incurred the costs to build Port Westward, even though PGE does not yet have a signed wind turbine contract for Phase I of its Biglow Canyon wind project and needs Biglow Canyon to complete its IRP action plan. PGE fully intends to complete its Biglow Canyon Phase I development as soon as possible. We are actively negotiating with potential counterparties for the turbines and our target on-line date is still December 31, 2007.

Q. Would it be good regulatory policy to withhold a determination of Port Westward's prudence until PGE signs turbine contracts for Biglow Canyon?

A. No. The Commission acknowledged PGE's final action plan. It did not acknowledge PGE's final action plan with all actions to be completed at the same time or in a particular order. Such a condition would unduly restrict PGE's ability to acquire the resources at the best prices for customers.

Q. What is the current status of PGE's Biglow Canyon Phase I development?

A. As stated on pages 57-58 of PGE Exhibit 1900, the Commission has issued two orders to facilitate PGE's development of Biglow Canyon, which can be built out in phases to a maximum of 450 MW.

Q. What specific milestones have been reached and what specific commitments have been made regarding overall Biglow Canyon development?

A. Milestones and commitments to date include:

- The Oregon Energy Facility Siting Council (EFSC) issued a final Project Site Certificate on June 30, 2006. The Site Certificate authorizes construction of up to 225 wind turbines, 450 MW, and a maximum wind turbine size of 3.0 MW. PGE has submitted an amendment requesting transfer of the site to PGE. We expect EFSC approval on November 3, 2006. PGE will make use of this authorization if we develop further stages of Biglow Canyon.
- PGE has acquired 400 MW of interconnection rights for the project with BPA and has paid $6.5 million to BPA to advance the interconnection project pending BPA

completion of its National Environmental Policy Act process necessary to offer PGE a Large Generation Interconnection Agreement (LGIA).

- BPA has completed its Environmental Impact Statement (EIS) and has advised that it has drafted a Record of Decision (ROD) to approve the EIS and will be in a position to offer PGE a LGIA very close to the end of October 2006. Pending review of the ROD and final LGIA, PGE will execute the LGIA following BPA's offer and execution.
- PGE has invested a total of approximately $7.8 million into the project as of September 30, 2006. In addition, PGE has executed a purchase order for a project transformer for Phase I at a cost of up to $2.0 million and is obligated to pay at least an additional $5.0 million for BPA interconnection facilities concurrent with execution of the LGIA.

Q. What part of the Biglow Canyon development is part of the 2002 IRP Final Action Plan?

A. Phase I of the Biglow Canyon development is part of the Final Action Plan. PGE has designed Phase I for a capacity of up to 126 MW, with expected energy of approximately 47 MWa. PGE remains in negotiations with two counter parties to acquire wind turbines. We prefer to obtain wind turbines for completion of Phase I by the end of 2007 but will delay completion to 2008 if turbines are not available at a reasonable price.

Q. Has PGE completed another wind supply action as part of its 2002 IRP Final Action Plan?

A. Yes. As part of the Final Action Plan, PGE entered into a 30-year purchase agreement with PPM Energy for the output of the Klondike II development. Expected output of this wind resource is 27 MWa.

Q. What specific milestones have been reached and what specific commitments have been made regarding the Biglow Canyon Phase I development?

A. Milestones and commitments to date include:

- In July 2006, PGE issued an Invitation for Bid to wind turbine manufacturers for supply of wind turbines for Phase I. Four of the manufacturers responded with bids and one additional supplier provided an unsolicited bid.
- PGE is in active negotiations with two parties, who can potentially make deliveries in time to facilitate our targeted December 31, 2007, on-line date.
- PGE generation engineering services has developed a draft design basis document and scope of work for Phase I. In addition, PGE generation engineering has authorized a third party contractor to begin design work on the project substation.
- PGE has requested and BPA has verbally approved redirection of 150 MW of point-to-point transmission rights currently held from 'Mid-C to PGE's service territory' to 'the project point of interconnection to PGE's service territory.'

Q. Has Staff stated a view on how the Biglow Canyon schedule might impact the prudence of Port Westward expenditures?

A. Yes. In its response to PGE Data Request No. 085, Staff states that it "does not agree with CUB's approach to determining the prudence of Port Westward." Staff also states that "[at] this point in this proceeding, Staff does not believe that CUB has successfully challenged the prudence of PGE's decision to build Port Westward." Finally, Staff states that "the record in this proceeding is not yet closed, and therefore Staff will provide its final recommendation on PGE's decision to build Port Westward, based on the final record in this proceeding, in its opening brief." We include Staff's complete response to PGE Data Request No. 085 as PGE Exhibit 2501.

Q. Does CUB make other recommendations concerning Port Westward?

A. Yes. Page 31 of CUB Exhibit 300 includes three conditions related to potential delays in Port Westward's on-line date. The first is that tariffs from this rate proceeding would be valid if Port Westward is used and useful within 30 days of its scheduled March 1, 2007, on-line date, i.e., if the plant can be used to serve customers by March 31, 2007. The second is that if Port Westward is not used and useful by March 31, 2007, PGE must re-open this docket. The third is that if Port Westward is not used and useful by September 1, 2007, PGE must file a new rate case.

Q. Do you agree with these conditions?

A. No. As stated in PGE Exhibit 1900, "It is highly unlikely that the test year revenue requirement will become stale within 30 days or even a few months. Nonetheless, we acknowledge CUB's concern and suggest that the Commission revise the first condition to allow three months slippage before applying the second condition and that the Commission not require a new rate case unless the plant's commercial operation is delayed beyond 2007." (PGE Exhibit 1900 pages 55-56).

III. Load Serving Considerations

Q. How do other parties treat PGE's obligation to provide on-demand power to customers?

A. Other parties overlook PGE's obligation to serve. First, ICNU disputes the need for capacity resources. PGE responded to this position on pages 36 and 37 of PGE Exhibit 1900. Second, Staff asserts that PGE simply dispatches its resources to market. Specifically, Staff states that "in actual operation of the system PGE does not base resource dispatch on the level of retail load." (Staff/1600, Wordley/7).

Q. Is this characterization complete?

A. No. Market prices are an important consideration in PGE's dispatch decisions. However, they are not the only consideration. PGE also bases its dispatch on other factors, most importantly meeting its obligation to serve customer loads and maintaining required reserves.

Q. Can you elaborate on how meeting loads and maintaining reserves factor into PGE's dispatch decisions?

A. Yes. The two most important considerations in the actual operation of PGE's system are meeting loads and maintaining required reserve margins in all hours of all days under all circumstances. We then make operational decisions, such as resource dispatch, purchases, and sales, so as to achieve the lowest possible overall net variable power costs. However, the most important considerations remain the obligation to meet loads and maintain required reserve margins under all circumstances.

Q. Can you provide an example of this practice?

A. Yes. We often enter high-load months with a small long position designed to provide additional coverage for load excursions.

Q. PGE Exhibit 2700 discusses how Commission decisions affect PGE's financial condition and its ability to attract capital. Does PGE's financial condition also affect its power supply activities?

A. Yes. If PGE's financial condition deteriorated to below investment grade, this would significantly impact PGE's ability to secure power supplies for customers at the lowest cost possible. The vast majority of PGE's unsecured credit lines with its wholesale counterparties would be reduced to zero. As a result, these counterparties would require prepayment and/or adequate margin for all current and forward positions.

IV. Qualifications

Q. Mr. Lobdell, please describe your qualifications.

A. I received a Bachelor of Science degree from the University of Oregon in 1984. Since joining PGE in 1984 I have held a variety of positions at PGE and its affiliates including Vice President, Risk Management, Reporting, and Control, Vice President of Portland General Distribution Company, Vice President of Portland General Holdings II, Vice President of FirstPoint Utility Solutions, Manager of Financial Risk Management and Pricing at PGE, Treasurer of Tule Hub Services Company, Manager of Commercial Group Accounting for Portland General Holdings, Project Manager for Columbia Willamette Development Company, and Supervisor of Accounting Operations for Portland General Corporation. I became PGE Vice President of Power Operations in September 2002. I entered my current position of Vice President of Power Operations and Resource Strategy in 2003.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2501	Staff Response to PGE Data Request No. 085.

October 18, 2006

TO: Patrick Hager
Portland General Electric Company

FROM: Maury Galbraith
Oregon Public Utility Commission

PORTLAND GENERAL ELECTRIC
UE 180/ UE 181/ UE 184
Staff Response to PGE Data Request No. 085
Dated October 10, 2006
Question 085

Request:

Please provide Staff's recommendation on the prudence of PGE's decision to build Port Westward. See Staff/1500, Galbraith/22 lines 11-14.

Response:

In direct testimony, Staff indicated that it had not discovered any issues or concerns regarding PGE's decision to build Port Westward. See Staff/800, Galbraith/3.

In rebuttal testimony, Staff indicated that it thought PGE had, in large part, successfully rebutted the Citizens' Utility Board (CUB) concern regarding the company's implementation of its 2002 Integrated Resource Plan (IRP) Final Action Plan. See Staff/1500, Galbraith/22. Staff also indicated that it intended to review CUB's rebuttal testimony before making its final recommendation to the Commission. See Staff/1500, Galbraith/22.

CUB, in its rebuttal testimony, indicated that it could not determine, at this time, the prudence of PGE's decision to build Port Westward and that the prudence of the investment will become more clear over time. CUB suggests that if PGE does not acquire the renewable resources included in its 2002 IRP Final Action Plan, then PGE's decision to build Port Westward may become imprudent. See CUB/300, Jenks-Brown/31.

Staff does not agree with CUB's approach to determining the prudence of Port Westward. If PGE does not acquire the renewable resources included in its 2002 IRP Final Action Plan, then the decision to not acquire the renewable resources could be the subject of a prudence challenge in a future rate proceeding. A potential adjustment in that future rate proceeding would be to impute the foregone renewable resources in PGE's rates. Staff believes that CUB's prudence challenge is misdirected. The challenge has more to do with PGE's decision-making with respect to renewable resources than it does with PGE's decision to build Port Westward.

At this point in this proceeding, Staff does not believe that CUB has successfully challenged the prudence of PGE's decision to build Port Westward. If the record in this proceeding were to close today, then Staff's final recommendation to the Commission would be that PGE's decision to build Port Westward be found prudent and that any prudently incurred costs be included in PGE's rates when the plant becomes used and useful. However, the record in this proceeding is not yet closed, and therefore Staff will provide its final recommendation on PGE's decision to build Port Westward, based on the final record in this proceeding, in its opening brief.

Table of Contents

I. Introduction

Q. Please state your name and positions with Portland General Electric.

A. My name is Jay Tinker. I am a Project Manager in the Regulatory Affairs department. My qualifications previously appeared in PGE Exhibit 200.

My name is Stephen Schue. I am a Senior Analyst in the Regulatory Affairs department. My qualifications previously appeared in PGE Exhibit 300.

My name is Ted Drennan. I am a Business Analyst in the Regulatory Affairs department. My qualifications previously appeared in PGE Exhibit 1900.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to various parties' positions in several specific areas. These include:

- Extrinsic value claims
- Capacity contract misconceptions
- Forced outage forecasts
- Staff simulation limitations
- PCA mechanism
- RVM timing

Q. What are your primary conclusions regarding the parties' proposals?

A. The Commission should:

- Not adopt the proposed reduction to PGE's forecasted NVPC for extrinsic value due to its one-sided nature.
- Calculate forced outage rates for PGE's plants consistent with the long-standing four-year rolling average methodology.

Q. How is your testimony organized?

A. In addition to this Introduction, our testimony has six sections.

In Section II, we rebut various unfounded claims from other parties about extrinsic value. We point out that Staff expects actual power costs to exceed forecasted costs, and compounds the problem of under-recovery by PGE by reduced forecasted NVPC for extrinsic value. We refute ICNU's extrinsic value claims by comparing the result of the ICNU calculation method with the value that MONET credits to customers. When we correct the calculation errors, ICNU's methodology results in a value that is actually less than what MONET already credits to customers.

Section III addresses ICNU's misconceptions with our capacity contracts.

In Section IV, we respond to other parties' continued request to change the methodology for forecasting forced outage rates. We dispute the need for a methodology change. If the Commission does decide that a change in methodology may be appropriate, we offer suggestions on making the process fair to <u>all</u> utilities.

Section V addresses Staff's simulation based on the PA Consulting Report. We note the limitations of the simulation results provided in Staff's surrebuttal testimony.

In Section VI, we respond to various PCA mechanism issues. These include adjustments for load variations, earnings test deadbands, and unintended consequences. We also demonstrate that PGE's 1979-1987 PCA was indeed comprehensive.

In Section VII, we address the implementation of power cost forecasting for 2007. Specifically, we discuss the timing of updates to our power cost forecast, and incorporation of Port Westward dispatch benefits.

II. Expected Value Power Costs and Extrinsic Value

Q. What is the purpose of this section of your testimony?

A. In this section, we rebut other parties' claims regarding extrinsic value. We show that MONET already places a higher value on PGE's gas-fired resources than would correct implementation of ICNU's methodology. We also show that Staff's methodology lacks a foundation, and that it would worsen, rather than improve, the accuracy of power cost forecasts, given evidence that expected NVPC are greater than the MONET forecast.

Q. What is the basis for other parties' extrinsic value proposals?

A. Staff and ICNU propose to reduce the MONET net variable power cost (NVPC) forecast because they believe that some of PGE's gas-fired resources and heat-rate-based contracts will produce margins higher than those in the MONET forecast. Staff also believes that PGE should pursue expected value power costs, but "[u]ntil the company develops and implements stochastic power cost modeling, staff's recommended extrinsic value adjustment improves the company's current NVPC estimate by ensuring customers receive all the benefits from the company's flexible power resources for which they are paying all the cost in rates." (Staff/1600, Wordley/10, lines 19-23). Staff further claims that "the extrinsic value adjustment will improve the consistency between the company's IRP/RFP and ratemaking processes." (Staff/1600, Wordley/10-11, lines 23-2).

Q. Staff claims that PGE is "confusing extrinsic value with the stochastic modeling of power costs." (Staff/1600, Wordley/4, lines 1-2). Is this correct?

A. No. Extrinsic value and stochastic power cost modeling are both responses to the same phenomenon: the impact of uncertainty on an otherwise static forecast of power costs. This is why Staff indicated in their opening testimony that if PGE were to model power costs stochastically, there would be no need for an extrinsic value adjustment. (Staff/200, Wordley/8, lines 16-18).

Q. Staff indicates it proposes an extrinsic value adjustment "to be fair and consistent to the company and to customers." (Staff/1600, Wordley/4, lines 6-7). Is such an adjustment fair or consistent?

A. No. The adjustment is neither fair nor consistent because it fails to incorporate all, or even a reasonably comprehensive subset of, the impacts that uncertainty may have on the company's forecast of net variable power costs. By incorporating only one aspect of the impact of forecasting uncertainty on PGE's power costs (*i.e.*, the extrinsic value of thermal resources), Staff is effectively cherry-picking the "good" aspects of uncertainty while ignoring the "bad" aspects.

The only attempt to address the full impact of forecasting uncertainty on PGE's power costs is the PA study (see PGE Exhibit 1803). Pages 42 and 43 of PGE Exhibit 1803, from the PA Consulting report, indicate that, under PA's modeling, the base MONET NVPC forecast is less than an expected NVPC. In the PA report, the base forecast is less than an expected NVPC by approximately $10 million. The sign of the difference is more important than the exact amount, given that PA used what are now old data. Thus, a more complete assessment of risk indicates that an appropriate adjustment to PGE's power cost forecast, if any, would increase the forecast. Given this evidence that MONET understates an expected NVPC, simply decreasing the MONET forecast by an extrinsic value adjustment would worsen the problem that the MONET forecast is less than an expected NVPC.

Q. Does Staff agree that there is greater risk of power cost under-recovery than over-recovery?

A. Yes. In Exhibit 1500, Staff states twice that "Staff believes that increases in NVPC are more likely than decreases in NVPC." (Staff/1500, Galbraith/4, lines 20-21 and at 7-8, lines 16-1). In spite of this, however, Staff proposes an extrinsic value adjustment that would only exacerbate this problem.

Q. Staff indicates that if the Commission either doesn't approve a PCA, or approves one, but with a deadband, an extrinsic value reduction is necessary. (Staff/1600, Wordley/5-6). Do you agree?

A. No, an extrinsic value reduction represents an ad-hoc approach to assessing the impact of forecasting uncertainty on power costs that ignores the negative consequences that uncertainty may have on PGE's power costs. It would also make it less likely that PGE would recover its power costs in any given year based on the results of the PA Study. Whether the Commission approves a PCA with a deadband or no PCA at all, the Commission should not approve an extrinsic value adjustment to PGE's power cost forecast. This issue is part of the fair allocation of cost-of-service risk discussed in Section II of PGE Exhibit 1800.

Q. But aren't customers paying the "full costs" of these resources?

A. No, they are not. The Commission has never adopted a regulatory framework under which customers pay all of the actual costs of PGE's resource portfolio, and Staff's proposed deadband (Staff/1500, Galbraith/4, line 6) on a PCA mechanism (combined with its belief that higher actual NVPC outcomes are more likely) would suggest that Staff does not want customers to pay the full costs in the future. If Staff believes a better regulatory framework is one under which customers pay the "full costs" and receive the "full value" of a utility's resources, a robust PCA with no deadband would be an appropriate tool to ensure that result.

"Full costs" are not just depreciated capital costs, but also the financial impact of the uncertainty discussed above.

Q. What is the specific basis for Staff's proposed extrinsic value NVPC reduction?

A. Staff states that "PGE's estimate of extrinsic value used to evaluate capacity resource options was the only estimate available to staff and consequently was used by staff to develop its proposed extrinsic value adjustment." (Staff/1600, Wordley/8, lines 20-23). The estimate referred to is one figure taken from PGE's analysis of the Super-Peak Contract within PGE's 2003 Request for Proposals (RFP) process, which itself was part of PGE's 2002 Integrated Resource Plan (IRP).

Q. Is this an appropriate basis for deriving an extrinsic value reduction to the NVPC forecast that includes the Super-Peak Contract, and several other resources, for the 2007 test year?

A. No. Staff took this figure from one part of the RFP evaluation process and used it to support a ratemaking adjustment related to the Super-Peak Contract and several other resources, particularly Beaver and Coyote, in the 2007 test year. PGE explained on pages 17-19 of PGE Exhibit 1900 why an analysis performed within the IRP/RFP process is not suitable for test year rate making. On pages 29-31 of PGE Exhibit 1900, PGE further explained why it is inappropriate to extrapolate information from a winter-only resource across the entire year for other resources.

Q. Did Staff make use of information on the Super-Peak Contract that is now available?

A. No. One winter season of Super-Peak dispatch history is now available. In fact, the contract dispatched only 12 hours during that period. Staff dismissed this information, stating that

"One year of actual experience provides no useful evidence regarding staff's estimate …" (Staff/1600, Wordley/9, lines 16-17).

Q. Did Staff make use of information provided by PGE on the inappropriateness of applying information for a winter-only resource to other resources, which are available all year?

A. No. Staff states that "when staff issued a discovery request asking the company to provide analysis or studies that support and demonstrate that extrinsic value is higher in the winter, the company could provide no convincing evidence." (Staff/1600, Wordley/10, lines 8-11).

Q. Did PGE, in fact, provide useful information?

A. Yes. PGE's response to Staff Data Request No. 620 provided useful information. In part, it stated:

> the basis for the assertion is the historical experience of PGE's trading floor personnel that an agreement with parameters like those of the Super-Peak Contract would have its highest value during the months of December through February, which is the Super-Peak "winter" contract period. This period corresponds to historical PGE peak loads and times of strained capacity. In other months an agreement with parameters like those of the Super-Peak Contract would have less value. In fact, in many months it would have essentially no value at all.

PGE's response to Staff Request No. 620 is included as PGE Exhibit 2601.

Q. What is your summary evaluation of Staff's extrinsic value methodology?

A. Staff inappropriately used one number from one part of an RFP analysis for one resource as the basis for test year adjustments for several PGE resources. This extreme extrapolation does not produce a credible result.

Q. How does ICNU calculate extrinsic value adjustment figures?

A. On page 13 of ICNU Exhibit 108, ICNU discusses two estimates, both of which are variants of the analysis first presented in ICNU Exhibit 103 (pages 7-8). Alternative 1 includes methodology corrections proposed in PGE Exhibit 1900 (page 32), but updates forward curves to those included in PGE's September 29, 2006, partial power cost update. Alternative 2 differs from Alternative 1 in that "the mean spread between gas and power is based on historical spreads, rather than the projected Monet spread." (ICNU Exhibit 108 at 13, lines 9-10).

Q. Does ICNU correctly update the forward curves in Alternative 1?

A. No. Rather than using the 2007 forward curves from the September 29, 2006, partial update, ICNU used the 2006 figures listed in Monet. These 2006 figures are not relevant to the 2007 test year.

Q. What is the effect of using the correct 2007 curves?

A. Use of the correct curves decreases Alternative 1 from $4.3 million to $3.4 million.

Q. Do you disagree with other aspects of ICNU's Alternative 1 calculation?

A. Yes, we disagree. It includes more than $220,000 in intrinsic value associated with Port Westward for January and February of 2007. This is inappropriate because the test year revenue requirement is based on a March 1, 2007, on-line date for Port Westward. It also uses NERC average forced outage rates for Coyote and Port Westward, which increases the result by approximately $50,000.

Q. Have you calculated Alternative 1 with all appropriate corrections?

A. Yes. Including these corrections decreases the Alternative 1 estimate by approximately an additional $200,000, to $3.2 million.

Q. Does the September 29, 2006, MONET power cost forecast credit customers with dispatch benefits for Coyote, Beaver, and Port Westward that are, in fact, greater than what ICNU advocates through Alternative 1?

A. Yes. The Alternative 1 estimated dispatch benefits are the sum of the $3.2 million of extrinsic value and an associated $38.2 million of intrinsic value based on the mean spreads, or a total of $41.4 million. However, the September 29, 2006, MONET partial update includes dispatch benefits of $44.3 million. In other words, the MONET run credits customers with almost $3 million more than ICNU advocates.

Q. What is the basis for the $44.3 million MONET dispatch benefit figure?

A. We used the hourly diagnostic report associated with the September 29, 2006, MONET run to calculate both the value of power output and the cost of (primarily) fuel for Coyote, Beaver, and Port Westward over the test year. The net was $44.3 million. The September 29, 2006, power cost update was only partial, and therefore did not include the hourly diagnostic report. However, we include this report in the electronic work papers for this testimony.

Q. Is your comparison of ICNU's recommendation and the dispatch benefits included in MONET similar to what you presented on page 34 of PGE Exhibit 1900?

A. Yes. It is simply an updated version of the same comparison. Table 1 below summarizes the updated comparison.

Table 1

Value of Coyote, Beaver, and PW Under ICNU Methodology

	Coyote	Beaver	PW	Total
Base Margins:	13,860,444	3,526,242	20,855,449	38,242,135
Extrinsic Value:	889,805	933,262	1,340,532	3,163,599
Total Value:	14,750,249	4,459,504	22,195,981	41,405,734

Value of Coyote, Beaver, and PW in March MONET Run

	Coyote	Beaver	PW	Total
Value of Output:	86,269,037	34,613,949	116,073,987	236,956,973
Cost of Output:	69,597,006	30,587,755	92,467,091	192,651,852
Net Value:	16,672,031	4,026,194	23,606,896	44,305,121

Q. Do you believe that ICNU's Alternative 2 is a reasonable approach?

A. No. Taking the forward curves from the September 29, 2006, partial update MONET run, but then using historical spreads, rather than those from the same partial update run, is inconsistent. It is simply a way to produce a higher extrinsic value estimate.

Q. Are there errors in the Alternative 2 calculation?

A. Yes. It includes more than $300,000 in intrinsic value associated with Port Westward for January and February of 2007. Again, this is inappropriate because of the expected on-line date for Port Westward. It also uses NERC average forced outage rates for Coyote and Port Westward, which increases the result by approximately $50,000. These corrections would reduce the Alternative 2 estimate from $5.9 million to $5.5 million. However, for the reason stated above, Alternative 2 does not have a reasonable basis, and should not be used.

Q. Please summarize your discussion of the proposed extrinsic value reductions to the NVPC forecast.

A. Staff and ICNU proposed these reductions because they lower the test year NVPC forecast. This "cherry-picking" approach simply exacerbates the problem that the MONET forecast is likely less than an expected NVPC. Staff's methodology is not credible, as it greatly overuses one figure. ICNU's (Alternative 1) methodology, when corrected and properly compared to the dispatch benefits credited to customers in the MONET forecast, actually indicates that such an adjustment should be an increase of almost $3 million in the test year NVPC forecast.

Q. ICNU criticizes PGE's use of the qualitative conclusions of the PA Consulting report, stating the "The PA model result is so far below the Monet result that one cannot have confidence that both models are correct." (ICNU/108, Falkenberg/4, lines 22-23). ICNU also characterizes the PA model as a "black box." (ICNU/108, Falkenberg/4, line 19). Is this criticism valid?

A. No. PA based its report on data that differ substantially from those used in the MONET forecasts that are part of this proceeding. Therefore, the results should be different. It would be a cause for concern if the results were the same. We relied on the PA report for qualitative results, not exact point estimates. In addition, the fact that results based on data from periods only a few years apart can differ substantially points out that power cost risk is large and that a PCA mechanism is needed to fairly deal with this risk.

It is not correct to characterize the PA model as a "black box" for two reasons. First, PGE retained PA to do an independent study that focused on the dispersion of power costs results, not exact point estimates. PA's modeling did this. Second, the "black box" characterization makes it seem that parties can do nothing at all with the PA results. This is incorrect. Staff performed a simulation based on PA's results (Staff/108, Galbraith/14-16).

Q. Staff and ICNU are critical of the example of extrinsic value provided by PGE in rebuttal testimony (PGE Exhibit 1900, pages 25-26). Staff states "Clearly, any number

of reasonable examples can be created using the company's "more complete view", the results of which are totally assumption driven." (Staff/1600, Wordley/8). ICNU states that PGE's example represents a flaw of logic (ICNU/108, Falkenberg/13) and cites an example where a specific event leads to additional margins without any negative consequences (ICNU/108, Falkenberg/15). How do you respond?

A. The purpose of the example was to show, using what we believe to be a plausible example, how a narrow view of extrinsic value <u>could</u> lead to the wrong conclusion about the impact of forecasting uncertainty on power costs. Clearly, there are an infinite number of combinations of actual circumstances that might deviate from a forecast. Our intent was not to state that this was the <u>only</u> possible outcome, but rather it was illustrative of the importance of considering all of the factors that are at risk. As Staff points out, the results will be assumption driven. That is exactly why any adjustment for the impact of uncertainty needs to be comprehensive in nature. Sometimes circumstances may arise that result in "good" outcomes (*e.g.*, widening spark spreads coupled with falling gas and electric prices and loads unchanged). Sometimes circumstances may arise that result in "bad" outcomes (*e.g.*, flat spark spreads with gas price spikes and load excursions). The only flaw in logic would be to adjust PGE's power costs by assuming away the "bad" outcomes associated with uncertainty.

Q. ICNU contends that PGE's example is nothing more than "numerology" and is plagued by poor assumptions such as the prospect for high regional gas prices in a primarily national gas market as well as the assumption that market heat rates and gas prices would move "lock step" (ICNU/108, Falkenberg, 14-15). How do you respond?

A. The Northwest markets may not have reached simultaneous $12/mmbtu gas and 12.0 mmbtu/MWh heat rate in the last four years. Based on ICNU Exhibit 118, however, it appears that, on December 7, 2005, gas prices were in excess of $12 with a market clearing heat rate above 11. PGE's example is just as valid with these data input assumptions. More importantly, even at far less extreme conditions, if a load excursion requires that PGE sell to customers rather than into the market, as assumed by ICNU in its example, the net impact to PGE would be negative. For example, at a gas price of $9/mmbtu, it would cost PGE more to produce power at Beaver to serve residential load than the revenue from that additional residential use. If the additional load being served by PGE were from our larger customers from whom we receive less tariff revenue, even lower gas prices could lead to negative outcomes.

Q. ICNU claims that PGE's tariff rate provides adequate compensation for incremental power demand such that customer optionality to consume more or less power can be effectively ignored in extrinsic value calculations (ICNU/108, Falkenberg/10-11). Do you agree?

A. No. Customer optionality to use more or less energy is a significant driver of the impact of risk on PGE's power costs and overall financial results. Any evaluation of the effect of risk on power costs should incorporate the load variable. As Staff pointed out in prior testimony, the variables that require evaluation to forecast power cost under uncertainty include "retail system loads, market prices for electricity and natural gas, thermal power plant forced outage rates, and hydro generation availability." (Staff/200, Wordley/3) While we believe that additional variables may also require evaluation, such as coal prices and regional supply/demand conditions, we agree that the load variable cannot be ignored.

Q. But ICNU claims that since mid-2002, the market price of power has exceeded PGE's average retail rate only a small fraction of the time (5.5% for heavy load hours and 2.75% for light load hours). (ICNU/108, Falkenberg/11). Doesn't this imply that PGE is "covered" for these load variations?

A. No. First, customer optionality includes <u>both</u> the option to use more energy and the option to use less energy at any time. Thus, even if Mr. Falkenberg's data represent a reasonable prediction of the future, PGE would clearly be exposed to negative financial results if customers were to use less energy and PGE would forego, on average, 7.85 cents of tariff revenue for each kWh reduction in usage and in return receive market energy revenues that met or exceeded this retail rate only a small fraction of the time.

Q. Do you believe that Mr. Falkenberg's data tell a convincing story that retail rates will be above market energy rates the vast majority of the time?

A. No. PGE's exposure to load variations can occur due to changing consumption patterns for any of its customers. For example, in 2005 the average tariff rate for PGE's Schedule 83-T customers was 5.04 cents/kwh[1]. Based on Mr. Falkenberg's data, the market price of energy exceeded 5.04 cents 26.8% of the heavy load hours and 12.8% of the light load hours. Thus, unexpected increases in demand from these larger customers have a significant chance of harming the company financially.

Q. Are there any other factors that suggest market energy rates may be more likely to exceed tariff rates than suggested by Mr. Falkenberg?

A. Yes. Mr. Falkenberg uses data from mid-2002. Market gas and electric prices have risen considerably since that time. It is debatable whether using data from 2002, or even 2003 or 2004, is relevant today. If, for example, data from 2004 to the present is used, market prices

[1] See 2005 FERC Form 1, pg. 304, line 25.

have exceeded the average retail rate 8.6% of the heavy load hours and 4.8% of the light load hours. Using data from 2005 to the present, the respective percentages are 7.0% and 8.1%. We also note that the average flat Mid-Columbia forward curve for 2007 as filed in this case was more than 6.0 cents/kWh. Thus, on an expected basis, market prices in 2007 exceed some PGE tariff rates, including Schedule 83-T, and are in fact approaching PGE's average retail tariff rate.

Q. Staff encourages PGE to continue pursuing expected value power cost modeling in part to "ensure a fair sharing of power cost risk between customers and the company." (Staff/1600, Wordley/10). Do you agree that expected value power cost modeling is capable of delivering this result?

A. No. Expected value power cost modeling may provide information about the probability and size of power cost outcomes that are different than forecast. Incorporating all of this in a forecast is, however, an inadequate regulatory response to forecasting uncertainty, if it is the only response. It erroneously implies that the risk has been dealt with simply because it was factored into the forecast for rates. The best that one can hope to achieve with expected value power cost modeling is an allocation of NVPC cost-of-service (COS) risk that has an equal probability (next year only) that actual NVPC will be either above or below the forecast. The appropriate tool to reduce NVPC COS risk is a reasonably structured PCA. There is a discussion of COS risk allocation in PGE Exhibit 1800, Section II, Part D.

Q. Do other parties propose additional adjustments to the MONET NVPC forecast?

A. Yes. On page 2 of Staff Exhibit 1600, Staff proposes an adjustment for ancillary services revenue. The basis for this adjustment is PGE's response to Staff Data Request No. 619.

Q. Do you agree with this calculation?

A. No. Staff's calculation does not remove approximately $100,000 in grid management charges imposed by the California Independent System Operator. In addition, we reiterate the statement made on page 47 of PGE Exhibit 1900, that, given the variation to date and future uncertainty of these revenues, the costs and revenues are best handled under a comprehensive variance tariff.

III. Capacity Contracts

Q. What are ICNU's conclusions regarding the capacity contracts included in PGE's test year NVPC forecast?

A. ICNU concludes:

- it is "very difficult to establish a need for peaking resources that have only been used a few hours over a period of several years." (ICNU/108, Falkenberg /16, lines 5-6).
- the "PPM Super Peak contract was justified on the basis of extrinsic value rather than the ratepayers' need for peaking capacity." (ICNU/108, Falkenberg /16, lines 8-9).
- utility "rates should only recognize *reasonable and necessary* costs. Capacity contracts that are seldom (or never) called upon do not result in *necessary* costs." (ICNU/108, Falkenberg /16, lines 12-14).
- in the "winter of 2005/2006, the entire 380 MW capacity from Boardman was out of service, yet PGE never needed to rely upon the PPM or Cold Snap contracts." (ICNU/108, Falkenberg /16, lines 22-24).

Q. Are these conclusions well founded?

A. No. First, ICNU mischaracterizes how long PGE has had the Cold-Snap and Super-Peak contracts, which began in January 2005 and December 2005, respectively. They did not begin "several years" ago.

Second, PGE did not justify the Super-Peak contract simply on the basis of extrinsic value. As discussed on page 36 of PGE Exhibit 1900, PGE selected the Super-Peak contract to help meet the capacity resource component of its 2002 IRP Final Action Plan. The need for capacity was the primary factor. An extrinsic value analysis helped to rank capacity resource bids received in response to PGE's 2003 RFP. PGE has an obligation to meet customer loads under extreme circumstances. Capacity resources help meet this obligation. The fact that they may not dispatch frequently does not make them unnecessary. Commission Order No. 04-375 acknowledged PGE’s 2002 IRP Final Action Plan, which included “400 MW of tolling capability for peak purposes.” PGE acquired this necessary tolling capability through the Super-Peak and Cold-Snap contracts.

Third, ICNU’s 2005/2006 winter example is not factually correct, and misses the point of capacity resources. As stated on page 19 of ICNU Exhibit 103, the Super-Peak contract (with PPM) did dispatch during its first winter season, although for a small number of hours. More importantly, the conclusion that PGE’s capacity contracts are not needed simply because PGE didn’t have to rely very much on them during the 2005/2006 winter (even though Boardman was not running) is erroneous. Capacity resources are needed for extreme circumstances that are largely regional in nature. Since the expected energy from Boardman during the winter of 2005/2006 was replaced with term purchases, the Boardman outage did not affect our use of the capacity contracts. Pages 36 and 37 of PGE Exhibit 1900 and PGE Exhibit 1910 provide evidence that we needed all of PGE’s resources under the extreme regional circumstances on July 24, 2006. Similarly extreme circumstances in the winter would require approximately 450 MW more resource capacity, making the 400 MW of capacity contracts (300 MW and 100 MW for the Cold-Snap and Super-Peak contracts respectively) necessary to meet customer load and reserve requirements.

IV. Forced Outage Rates

Q. What is the purpose of this section of your testimony?

A. In this section, we discuss other parties' continued requests for changes in the methodology for calculating forced outage rates which run contrary to the Commission's original intent in establishing the methodology. We also offer suggestions for making the process fair to all utilities, if the Commission decides to consider methodology changes.

Q. Staff Exhibit 102 is a 1984 Staff memo that established the use of the current four-year rolling forced outage rate for rate making. What was Staff's intent with this method?

A. According to the memo, Staff intended:

> "to propose a method for calculating performance that can be applied uniformly from plant to plant and from company to company." (Staff/102, Galbraith/4)

Q. Will the use of NERC data as proposed by Staff, ICNU, and supported by CUB in this case meet with the original intent?

A. No. The new proposals will not be applied uniformly across companies, only to PGE. The method will not be applied uniformly across plants, only a subset of PGE's units. The method is not even applied uniformly by the parties. Staff suggests Boardman and Colstrip use NERC data, ICNU includes Coyote, and CUB simply adds that it agrees with the use of NERC data.

Q. Why did Staff choose a four year period in 1984?

A. As stated in Staff/102, Galbraith/4, the memo states::

> The reason I propose using a 48 calendar month rolling average is that it reflects recent plant experience, which I think tends to better portray expected operation over the coming year.

Q. Have any of the parties shown NERC data to be more accurate in predicting plant operation?

A. No, as we stated previously. (PGE Exhibit/1900, Tinker-Schue-Drennan/42). No parties attempt to rebut this argument.

Q. In this case, Staff suggests removing extreme events, or extreme outage rates. Did the 1984 memo recognize this possibility?

A. Yes, at least partially. The memo did not, however, suggest that a high forced outage rate for a single year was, by itself, a reason for removing events from the 48-month average as Staff and ICNU suggest doing in the present case. (Staff/1500, Galbraith/17, ICNU/100 RJF/8).

As noted by Staff in its opening testimony, an extreme outage was excluded for PacifiCorp's Hunter unit. (Staff/100, Galbraith/7). However, in this docket parties have not suggested exactly what level qualifies as an extreme outage rate, except that the rate for Colstrip in 2002 qualifies. Staff Exhibit 102, a copy of the 1984 memo, mentions removal of an early Boardman outage in the forced outage calculations. (Staff/102, Galbraith/14). The memo also states:

> As in all aspects of rate making, if we can reasonably establish that substandard performance was due to poor or imprudent management then we should disallow some cost or adjust the historical EOR or MW net. (Staff/102, Galbraith/17)

Q. Have any of the parties presented evidence in the current case of imprudent management for Boardman, Colstrip, or Coyote?

A. No. They have not.

Q. Is it necessary to abandon the 4-year average altogether to address extraordinary plant outages?

A. No. It is possible to remove the days associated with particular events from the calculation. Staff discussed this approach for the recent Boardman outage in its opening testimony.

(Staff/100, Galbraith/7). There is also an interplay with any PCA mechanism. A sharing regime mitigates problems associated with forced outage assumptions; a deadband can be more problematic.

Q. Are there other issues with parties' positions on removing the 2005 Boardman outage, and Colstrip for all of 2002?

A. Yes. First, regarding Boardman, UM 1234 is addressing the 2005-2006 outage. We expect guidance from the Commission regarding treatment for the portion of this outage during the deferral period, which should also inform us on how to derive the four-year average for this docket.

Second, regarding Colstrip, there has been no evidence presented on imprudence, either in this case, or the 2004, 2005, or 2006 RVM proceedings, or in PacifiCorp's recently completed rate case. As stated above, the only rationale is that it is an "extreme outage rate." If this is indeed a proper standard, fairness would require removal of years when plants perform exceptionally well. Coyote had such exceptional performance in 2002, 2004 and 2005 with forced outage rates of 1.6, 0.76, and 1.01 percent, respectively. Parties are not clamoring for removal of these exceptional outage rates. Inclusion of only exceptionally good years is asymmetric treatment, and improper.

Q. What is Staff's response to your concerns with its choice of peer groups for Boardman and Colstrip?

A. Staff disregards our concern that NERC itself is critical of the method Staff and ICNU used in choosing peer groups for plant comparisons. Staff states that, from its review of the NERC benchmarking,

> The material describing these benchmarking services does not indicate the sign or magnitude of the potential bias. (Staff/1500, Galbraith/19, lines 14-16)

Staff does not deny that bias exists.

Q. Staff suggests the optimal peer group may have a lower forced outage rate than its chosen peer group, "in other words, the optimal peer group for the Boardman unit may have a lower forced outage rate than the standard peer group based on fuel type and capacity." (Staff/1500, Galbraith/19, lines 17-19). Is this proper justification for selecting a peer group?

A. No. This is just speculation. The optimal peer group could have a higher, or lower, forced outage rate. Conceivably the optimal peer group's rate could equal the overall average.

Q. Staff calls the NERC data "verifiable and objective." (Staff/1500, Galbraith/19, line 24). Is this correct?

A. This does not appear to be true. PGE could not verify ICNU's NERC data. (PGE Exhibit/1900, Tinker-Schue-Drennan/44). Further, ICNU could not explain the differences in their data and those that PGE found on the NERC website. ICNU states:

> It is possible that NERC may have retroactively revised its figures after I obtained these documents from its web page. (ICNU/108, Falkenberg/18, lines 18-20)

ICNU rationalizes away the differences stating:

> "it makes little difference, because the numbers differ by only a small amount." (ICNU/108, Falkenberg/18, lines 20-21)

Similar to Staff's 'defense' of peer group choice, ICNU's defense seems weak.

Q. Do you have any other issues with the contention of 'verifiable and objective' data?

A. Yes. As shown above we could not verify the data on a macro level. We are also unaware how one would verify the data on a plant-specific level. PGE is doubtful that we, or any other party, could verify that the data included in the NERC dataset are correct, especially when such data involve plants outside of our control.

It may be that the data are "objective" from the NERC standpoint, *i.e.*, NERC probably has no stake in presenting the data figures in one way or another. On a plant-specific level, there may be issues of objectivity. As stated in our testimony (PGE Exhibit/1900, Tinker-Schue-Drennan/43), plants may not report outages in the same manner.

Q. The current method of forecasting forced outage rates is well established, having been in place for more than 20 years. If the Commission decides it would like to change methodologies, what should it consider?

A. Any change should be well reasoned, not based on a single occurrence. (Staff/1500, Galbraith/19). Any change should include all utilities, not strictly PGE. Any change should include all units, not a subset of units (unless there are appropriate reasons). Any change, if using NERC data, should rely on the appropriate peer group, not an overall average that may or may not be reflective of the generating unit in question.

Q. How should the Commission proceed with any changes to the current forced outage methodology?

A. One possibility is to open an investigation so that all utilities and stakeholders could participate. This investigation would focus on alternatives to the current methodology, such as use of NERC data. If the investigation shows more accurate or more appropriate alternatives, the Commission should consider changes to its current policy.

Q. How did Staff and ICNU misconstrue PGE's statements regarding forced and planned outages?

A. Both parties suggest that PGE trades off planned outages for forced outages. This is not correct. Our testimony discussed our concerns with NERC data, especially potential reporting by other operators of forced outages as planned outages. (Staff/1500, Galbraith/18, ICNU/108, Falkenberg/17). At no point did we say our plants forego planned maintenance at the expense of forced outage rates. Rather, we explained that our plants have reasonable performance levels when looking at an equivalent availability factor (EAF). Use of the NERC EAF data for comparison reflected our concerns with NERC forced outage data.

Q. ICNU states that the comparison of the NERC EAF figures for 2001-2004 with PGE units' EAF figures for the same period is "off-base and irrelevant." (ICNU/108 Falkenberg/17). Do you agree?

A. No. We were attempting to compare like time periods. NERC data for 2005 performance are not available then, or now. We should also note there was a discrepancy in the Colstrip EAF numbers. We inadvertently listed the 2002-2005 EAF figures, as opposed to those for 2001-2004. Table 2 below is a corrected version of Table 6 in PGE/1900, page 39, along with the 2005 EAFs for Boardman and Colstrip. Again, it is evident that PGE's plants perform well in comparison on an EAF basis.

Table 2

	Four-Year Average						
Coal Plants 400-599MW	(2002-2005)	(2001-2004)	2005	2004	2003	2002	2001
Boardman EAF	78.47%	83.83%	69.87%	70.98%	88.20%	84.83%	91.32%
NERC EAF		83.74%		84.89%	84.17%	83.12%	82.77%
	Four-Year Average						
Coal Plants 600-799MW	(2002-2005)	(2001-2004)	2005	2004	2003	2002	2001
Colstrip EAF	84.14%	81.97%	92.48%	83.33%	83.80%	76.95%	83.81%
NERC EAF		84.16%		83.62%	85.74%	84.06%	83.20%

Q. What are your conclusions?

A. NERC data are inappropriate for ratemaking purposes. The data have not been shown to be objective and verifiable, and it is inappropriate to use data when we are uncertain how incorrect they may be.

We recommend that the Commission continue with the traditional method of calculating forced outage rates for rate making purposes. Any change in methodology should be well reasoned, not reactionary. A single event, the 2005 Boardman outage, does not require a change in methodology that violates the original intent of using the four-year average. The proposed changes treat PGE's plants differently both on a plant basis, and on a utility basis.

Finally, it is unfair and arbitrary to adjust or remove outage rates for a single year based solely on unsubstantiated claims that an outage or outage rate is "extreme." Parties have not demonstrated, or even suggested, imprudence for Colstrip during 2002. Should the Commission decide to remove an entire year from the calculation, fairness dictates removal of years with exceptional outage rates as well.

V. Simulation Based on PA Consulting Report

Q. What is your understanding of the basis for the statements on pages 14-16 of Staff Exhibit 1500 about the statistical characteristics of Staff's proposed power cost adjustment mechanism?

A. It is our understanding that Staff ran simulations of NVPC outcomes based on the parameters developed in the PA Consulting report. Specifically, Staff ran simulations with parameters that either reproduced or bounded those listed on page 7-39 of the PA Consulting report, reproduced as page 43 of PGE Exhibit 1803. Staff then summarized the simulation results in Table 3 on page 15 of Staff Exhibit 1500. This summary also includes the interaction between Staff's proposed PCA mechanism and the NVPC simulation results.

Q. Have you examined the simulation results summarized in Table 3 of Staff Exhibit 1500?

A. Yes. Table 3 accurately summarizes the simulation results and their interaction with Staff's proposed PCA mechanism, given the parameters taken from page 7-39 of the PA report.

Q. Are there limitations on what can be inferred from the Staff's Table 3 results?

A. Yes. These results are only consistent with the data PA used – electric and gas prices, hydro production, etc., from historical periods. For example, the gas and electric price data that PA used were from periods beginning in the 1990s. These underlying data can change, sometimes greatly, over time. Therefore, the Table 3 results would change over time as well.

Q. Does Staff discuss the expected frequency with which its proposed PCA mechanism would trigger?

A. Yes. Staff states that its "proposed PCA mechanism could be expected to result in recovery/refund in at least 7 out of 10 years." (Staff/1500, Galbraith/15, lines 6-7).

Q. Is this an important consideration in evaluating Staff's proposed mechanism?

A. No. How a regulatory framework allocates deviations in actual from forecasted NVPC is much more important than how often. In other words, the size of the deadband (could be zero, as in PGE's proposal), and the size(s) and percentage(s) of the sharing band(s), are very important considerations. Once these are set, the frequency with which the mechanism triggers will vary with the many factors which influence actual power costs. It is also important to note that Staff's statement is based on "10,000 random draws from each of four different distributions." (Staff/1500, Galbraith/14, lines 11-12). Any particular sample of one or at most a few years would likely exhibit considerable variation.

VI. PCA Mechanism Issues

Q. What is the purpose of this section of your testimony?

A. In this section, we respond to other Parties' proposals for load variation adjustments and earnings test deadbands, and unintended consequences that might result from these proposals. We also discuss how PGE's 1979-1987 PCA was comprehensive.

Q. Does ICNU propose a method to adjust for load variations?

A. Actually, ICNU proposes two different mechanisms. The first was described in ICNU's opening testimony. (ICNU/103, Falkenberg/46-47). It basically assumes perfect knowledge of future loads by adjusting at the forward curve used to set rates. We discussed the shortcomings of this approach in our rebuttal testimony. (PGE Exhibit 1900 at 12). In its rebuttal testimony, ICNU proposes to use a method that Avista uses in Washington.

Q. Are you familiar with Avista's method?

A. Yes. It is essentially the load adjustment mechanism used by PGE in its UE 115 PCA. That is, it is an adjustment based on the average total production costs (fixed and variable) of the utility. While such an adjustment has merit, we did not propose it in this case because of the widespread criticism we received from parties (including ICNU) from the application of the UE 115 mechanism during the October 2001 through December 2002 time period.

Q. Has the Commission previously approved mechanisms that included PGE's proposed formulation for treatment of load variations?

A. Yes. As stated on page 36 of PGE Exhibit 400, PGE's 1979-1987 PCA included this formulation.

Q. Do you agree with ICNU that this issue has not been fully developed in the current record?

A. No. We have now had five rounds of testimony in this docket. If ICNU has not fully developed its position, it is not for lack of opportunity.

Q. What earnings test deadband do Staff and CUB propose?

A. Staff and CUB propose a +/- 100 basis point earnings deadband.

Q. Have you analyzed the earnings deadband proposed by Staff and CUB?

A. Yes. PGE Exhibits 2602 and 2603 provide analyses of the interaction of an earnings deadband and possible O&M cost savings over an extensive range of possible circumstances. Section II of PGE Exhibit 2400 also includes a discussion of cost savings and possible unintended consequences of an earnings deadband (PGE/2400, Lesh/11-13).

Q. ICNU contends the 1979-1987 PCA was not comprehensive, based on exclusion of coal and nuclear fuel. (ICNU/108, Falkenberg/5-6). Is this correct?

A. When the PCA was established in 1979, that is correct. Of course, in 1979 PGE had no coal resources. However, by March 17, 1981 PGE's tariff had changed and the PCA included coal and nuclear costs. Page one of Schedule 100, included as PGE Exhibit 2604, includes the following:

> The total power cost will be determined as the sum of the fuel expense of all Company-owned or leased generating facilities, costs of carrying fuel oil inventories and net results of sales from inventory, the net cost of purchased power, and the cost of transmission of electricity by other systems, less the revenues from sale for resale.

This comprehensive formulation continued until the PCA was terminated in 1987.

VII. Power Cost Forecasting and Implementation

Q. What is the purpose of this section of your testimony?

A. In this section, we discuss the timing of our power cost forecast updates, and incorporation of Port Westward dispatch benefits.

Q. Does ICNU make a proposal regarding resource changes between general rate cases?

A. Yes. ICNU proposes that "if a PCAM is adopted, the actual costs be computed using all actual resources and any projections of power costs should do the same." (ICNU/108, Falkenberg /5, lines 10-12).

Q. Does PGE accept ICNU's proposal?

A. PGE generally accepts ICNU's proposal, with the understanding that "actual resources" includes changes in resource capacities between general rate cases. In other words, MONET forecasts between general rate cases would include changes in the capacities of existing resources.

Q. ICNU summarizes its proposed adjustments to PGE's filed NVPC forecast at ICNU/108, Falkenberg/21. Has PGE updated the forecast of NVPC since the initial filing in this case?

A. Yes. Table 3 below summarizes the updates to NVPC.

Table 3
Power Cost Forecast Updates

Filing Date	NVPC Without Port Westward ($000s)	NVPC With Port Westward ($000s)	Cost-of-service Busbar Load (MWa)	Total System Busbar Load (MWa)
Mar 15, 2006	856,968	847,321	2,405	2,416
July 28, 2006	878,566	857,603	2,405	2,416
Aug 21, 2006	888,714	870,604	2,399	2,414
Sept 29, 2006	860,861	856,898	2,399	2,414
Nov 2, 2006		To be filed		
Nov 9, 2006		To be filed		

Q. Does PGE anticipate future updates to NVPC?

A. Yes. In accordance with our standard RVM schedule, PGE will file an update on November 2, 2006, which will lock down all inputs to MONET except for forward curves. The final update on November 9, 2006, will update forward curves only and will be final, except that PGE may need to file updated NVPC forecasts to comply with a Commission Order on the contested NVPC issues in this case.

Q. Is PGE aware of any significant changes since its September 29, 2006, NVPC update was filed?

A. Yes. A month-long direct access window was completed at the end of September. As a result of that opportunity, customers with a significant amount of load gave PGE notice that they will not take a cost-of-service pricing option from PGE by selecting either a 3- or 5-year opt-out under Schedule 483 beginning in 2007. PGE is incorporating the impact of these decisions into an updated load forecast, which will be filed with the November 2 NVPC update. As a result of this change, we expect a significant reduction in 2007 cost-of-service load, NVPC and revenues.

Q. Will Port Westward dispatch benefits calculated without the Annual Update Tariff be effective for rates at a different time than the on-line date of Port Westward?

A. No. PGE is still proposing that all of the costs and benefits of Port Westward be implemented for rates with the on-line date of the plant. Since PGE cannot charge customers for the fixed costs associated with Port Westward until the plant is "in-service", we believe it is fair that any associated dispatch benefits be withheld until the "in-service" date as well. Thus, if Port Westward is "in-service" in March 2007, as expected, customers would be charged the costs and receive the benefits of Port Westward beginning then.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2601	PGE Responses to OPUC Data Request No. 620
2602	Interaction of Earnings Deadband and O&M Savings
2603	Interaction of Alternative Earnings Deadband and O&M Savings
2604	PGE Schedule 100

September 28, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated September 21, 2006
Question No. 620

Request:

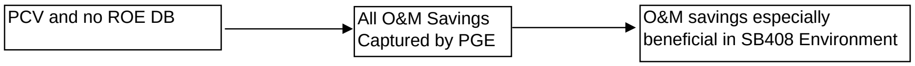
Please provide the analysis or studies that support and demonstrate the Company's assertion in PGE Exhibit 1900, page 30, lines 13-16.

Response:

PGE has not performed such specific analyses or studies for the Super-Peak Contract for months other than those offered by the bidder. However, the basis for the assertion is the historical experience of PGE's trading floor personnel that an agreement with parameters like those of the Super-Peak Contract would have its highest value during the months of December through February, which is the Super-Peak "winter" contract period. This period corresponds to historical PGE peak loads and times of strained capacity. In other months an agreement with parameters like those of the Super-Peak Contract would have less value. In fact, in many months it would have essentially no value at all.

Incentives for O&M Savings with Power Cost Variances and ROE Deadbands

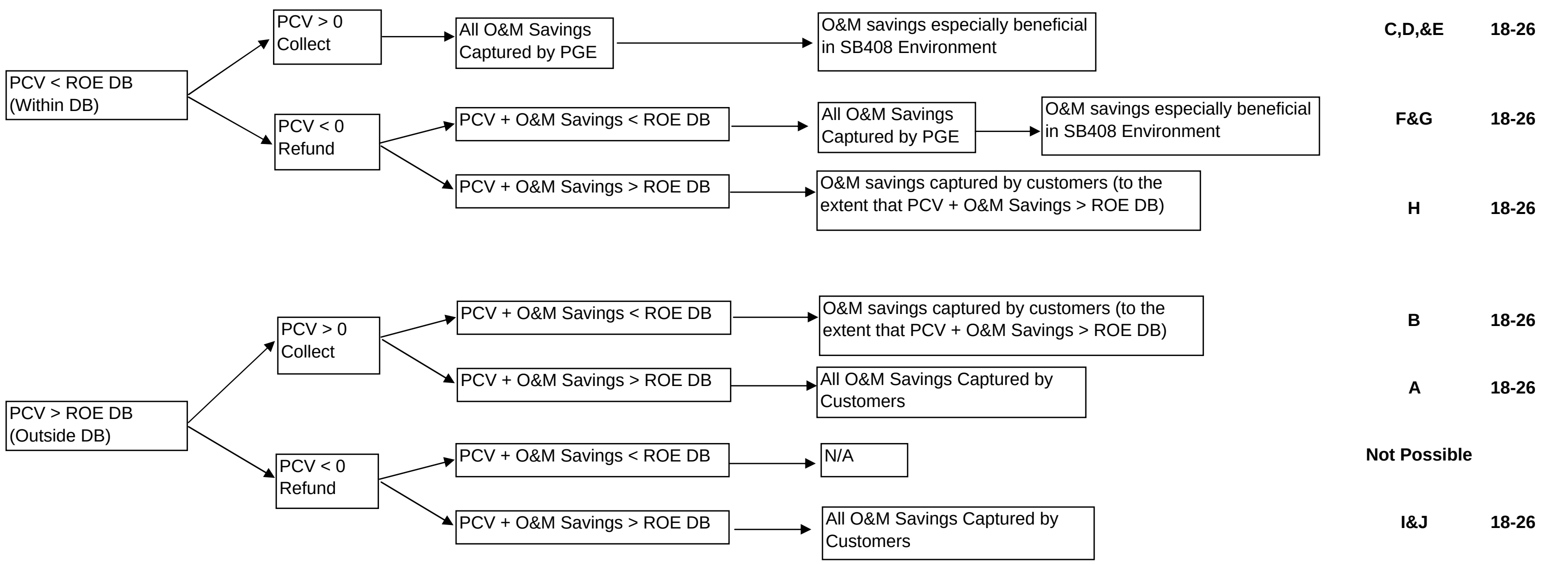
O&M Savings with Power Cost Variance and No ROE Deadband



O&M Savings with Power Cost Variance and an ROE Deadband

PCV = Amount Owed to Customers or to be Collected from Customers from PCA

Columns Rows



Summary:

PGE Captures All or part of O&M Savings if:

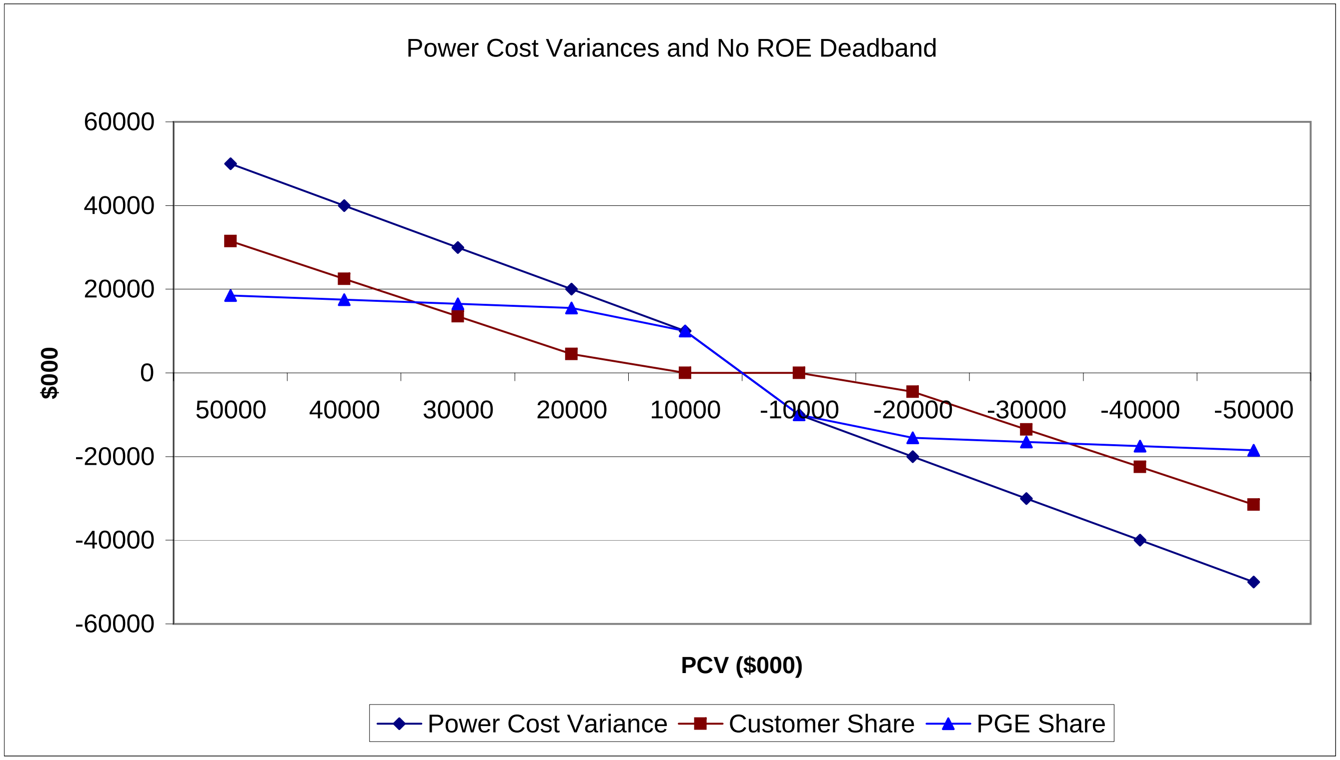
1) The net of collections and O&M savings are within the ROE deadband.
2) The sum of refunds and O&M savings are within the ROE deadband.

Customers Capture All or Part of O&M Savings if:

1) The net of collections and O&M savings are outside the ROE deadband.
2) The sum of refunds and O&M savings are outside the ROE deadband.

Examples with Power Cost Variances, Deadbands and Sharing, ROE Deadband, and O&M Savings
($000)

Line No.	Power Cost Variance	(A) 50000	(B) 40000	(C) 30000	(D) 20000	(E) 10000	(F) -10000	(G) -20000	(H) -30000	(I) -40000	(J) -50000
	Scenarios With No ROE Deadband:										
1	PCV Deadband	15,000	15,000	15,000	15,000	10,000	(10,000)	(15,000)	(15,000)	(15,000)	(15,000)
2	PGE Sharing Tier	3,500	2,500	1,500	500	-	-	(500)	(1,500)	(2,500)	(3,500)
3	**PGE Share of Excess PC**	**18,500**	**17,500**	**16,500**	**15,500**	**10,000**	**(10,000)**	**(15,500)**	**(16,500)**	**(17,500)**	**(18,500)**
4	Customer Sharing Tier	31,500	22,500	13,500	4,500	-	-	(4,500)	(13,500)	(22,500)	(31,500)
5	**Customer Share of Excess PC With No ROE Deadband**	**31,500**	**22,500**	**13,500**	**4,500**	**-**	**-**	**(4,500)**	**(13,500)**	**(22,500)**	**(31,500)**
6	Total Excess Power Costs Shared	50,000	40,000	30,000	20,000	10,000	(10,000)	(20,000)	(30,000)	(40,000)	(50,000)
	Scenarios with O&M Savings but No ROE Deadband:										
7	Maximum Collection/(Refund) of Excess PC	31,500	22,500	13,500	4,500	-	-	(4,500)	(13,500)	(22,500)	(31,500)
8	O&M Savings	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)
9	**Maximum Collection/(Refund) with No ROE Deadband**	**31,500**	**22,500**	**13,500**	**4,500**	**-**	**-**	**(4,500)**	**(13,500)**	**(22,500)**	**(31,500)**
10	**PGE Share with No ROE Deadband and O&M Savings**	**18,500**	**17,500**	**16,500**	**15,500**	**10,000**	**(10,000)**	**(15,500)**	**(16,500)**	**(17,500)**	**(18,500)**
11	**Amount of $7.5 Million O&M Savings Captured by Customers**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
12	**Amount of $7.5 Million O&M Savings Captured by PGE**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**
	Scenarios With 100 BP ROE Deadband:										
13	Approximate Revenue for 100 BP of ROE Deadband (Based on UE-180 Revenue Requirement With PW)	17,500	17,500	17,500	17,500	17,500	(17,500)	(17,500)	(17,500)	(17,500)	(17,500)
14	Possible Collection/(Refund) of Excess PC	31,500	22,500	13,500	4,500	-	-	(4,500)	(13,500)	(22,500)	(31,500)
15	**Maximum Collection/(Refund) with 100 BP ROE Deadband**	**14,000**	**5,000**	**-**	**-**	**-**	**-**	**-**	**-**	**(5,000)**	**(14,000)**
16	**PGE Share with 100BP ROE Deadband**	**36,000**	**35,000**	**30,000**	**20,000**	**10,000**	**(10,000)**	**(20,000)**	**(30,000)**	**(35,000)**	**(36,000)**
17	Delta ROE from Collection/Refund	0.80%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-0.29%	-0.80%
	Scenarios with O&M Savings and a 100 BP ROE Deadband:										
18	Maximum Collection/(Refund) of Excess PC	31,500	22,500	13,500	4,500	-	-	(4,500)	(13,500)	(22,500)	(31,500)
19	Maximum Collection/(Refund) with 100 BP ROE Deadband	14,000	5,000	-	-	-	-	-	-	(5,000)	(14,000)
20	O&M Savings	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)
21	**Maximum Collection/(Refund) with ROE Deadband**	**6,500**	**-**	**-**	**-**	**-**	**-**	**-**	**(3,500)**	**(12,500)**	**(21,500)**
22	**PGE Share with 100 BP ROE Deadband and O&M Savings**	**43,500**	**40,000**	**30,000**	**20,000**	**10,000**	**(10,000)**	**(20,000)**	**(26,500)**	**(27,500)**	**(28,500)**
23	Delta ROE from Collection/Refund	0.37%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-0.20%	-0.71%	-1.23%
24	**Amount of $7.5 Million O&M Savings Captured by Customers**	**7,500**	**5,000**	**-**	**-**	**-**	**-**	**-**	**3,500**	**7,500**	**7,500**
25	**Amount of $7.5 Million O&M Savings Captured by PGE**	**-**	**2,500**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**	**4,000**	**-**	**-**
26	Total O&M Savings Shared	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500



Power Cost Variances and No ROE Deadband
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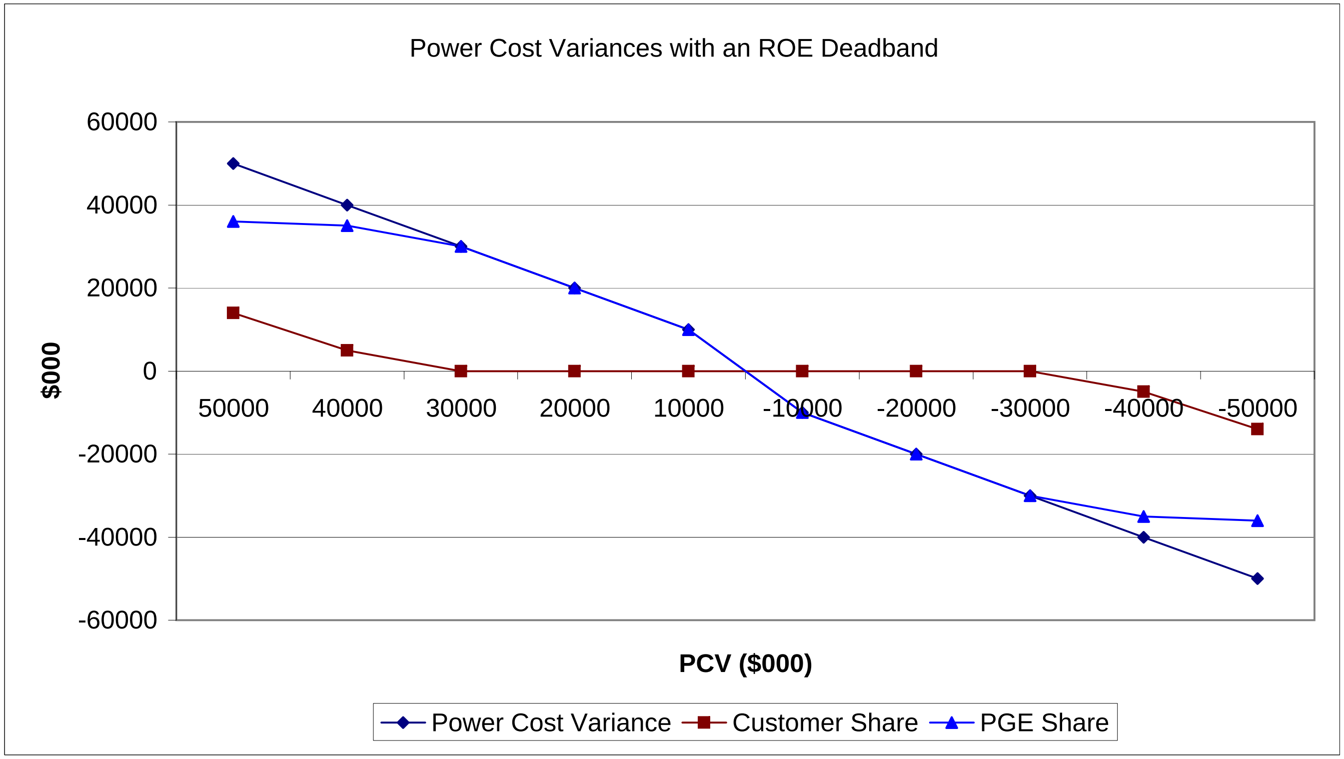
PCV ($000)
Power Cost Variance
Customer Share
PGE Share


Power Cost Variances with an ROE Deadband
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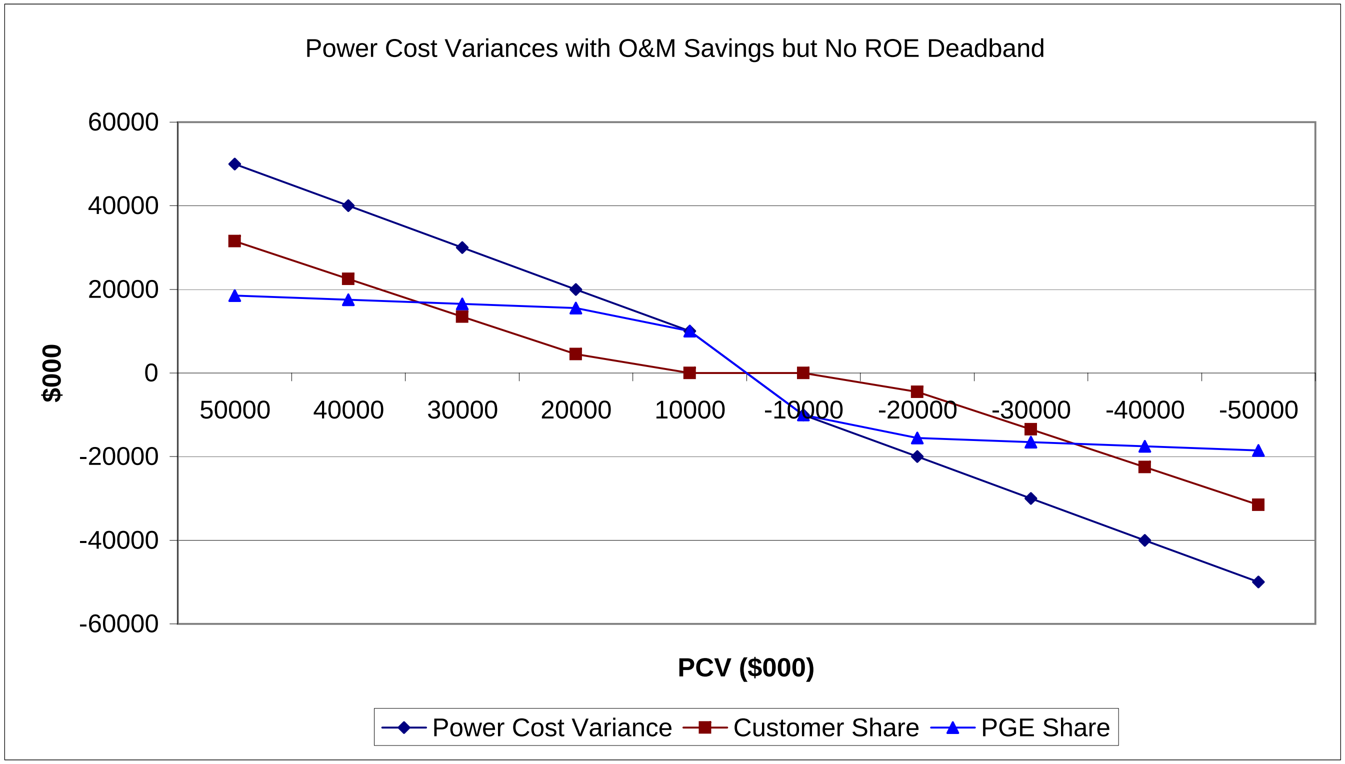
Power Cost Variance
Customer Share
PGE Share


Power Cost Variances with O&M Savings but No ROE Deadband
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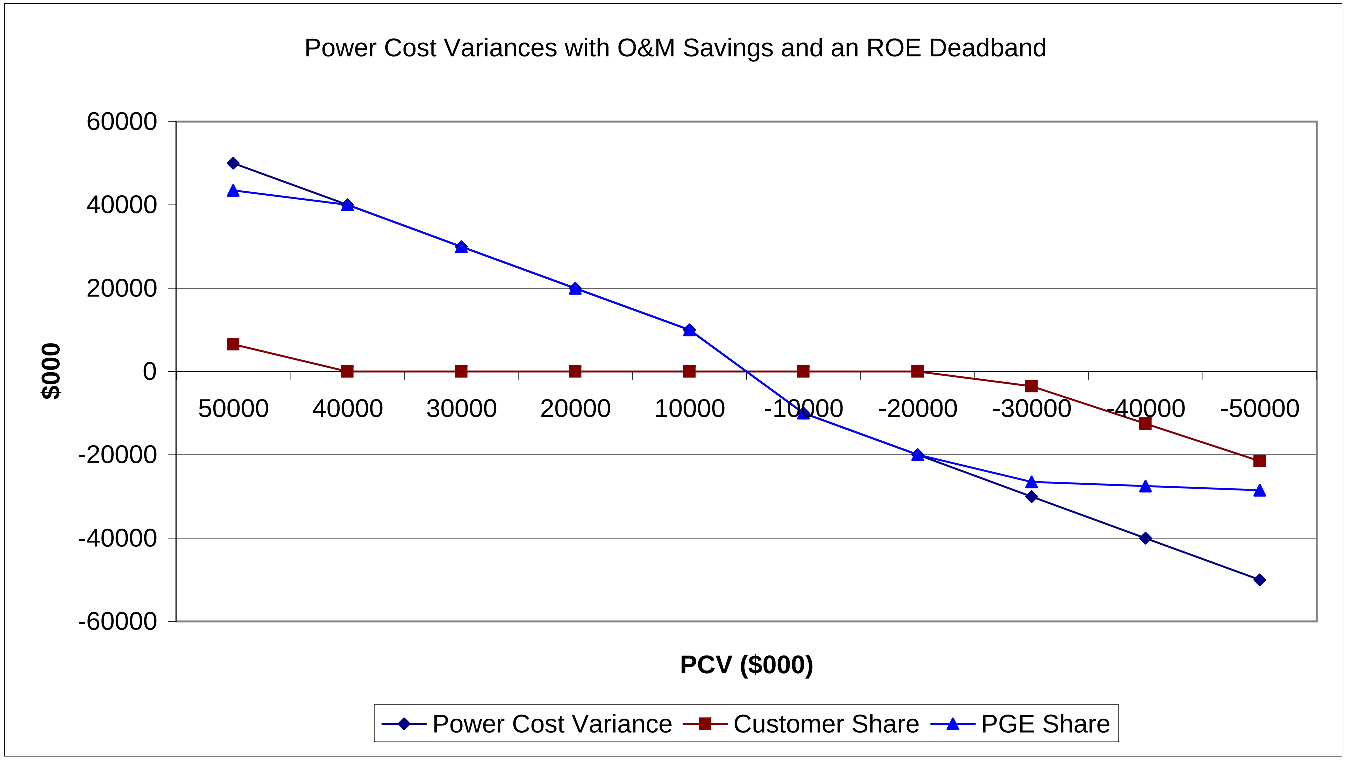
Power Cost Variance
Customer Share
PGE Share


Power Cost Variances with O&M Savings and an ROE Deadband
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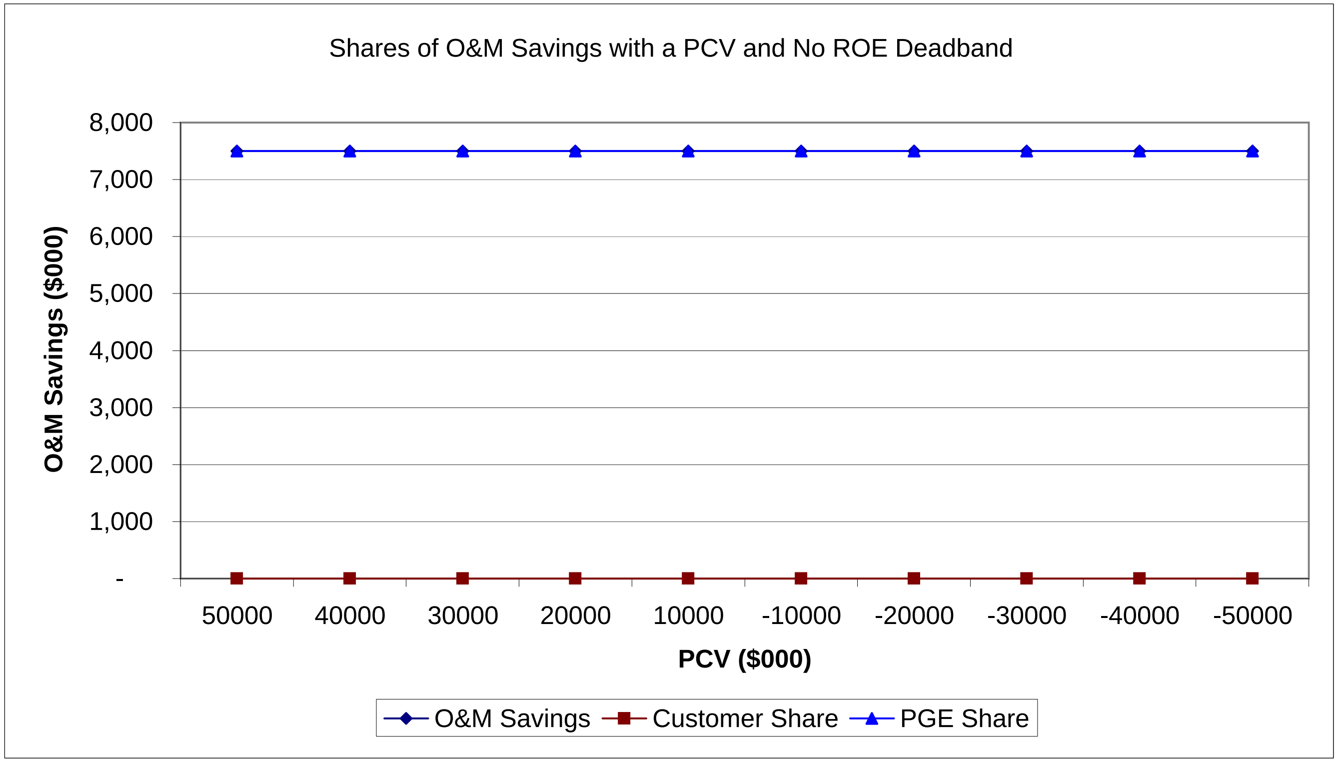
PCV ($000)
Power Cost Variance
Customer Share
PGE Share


Shares of O&M Savings with a PCV and No ROE Deadband
8,000
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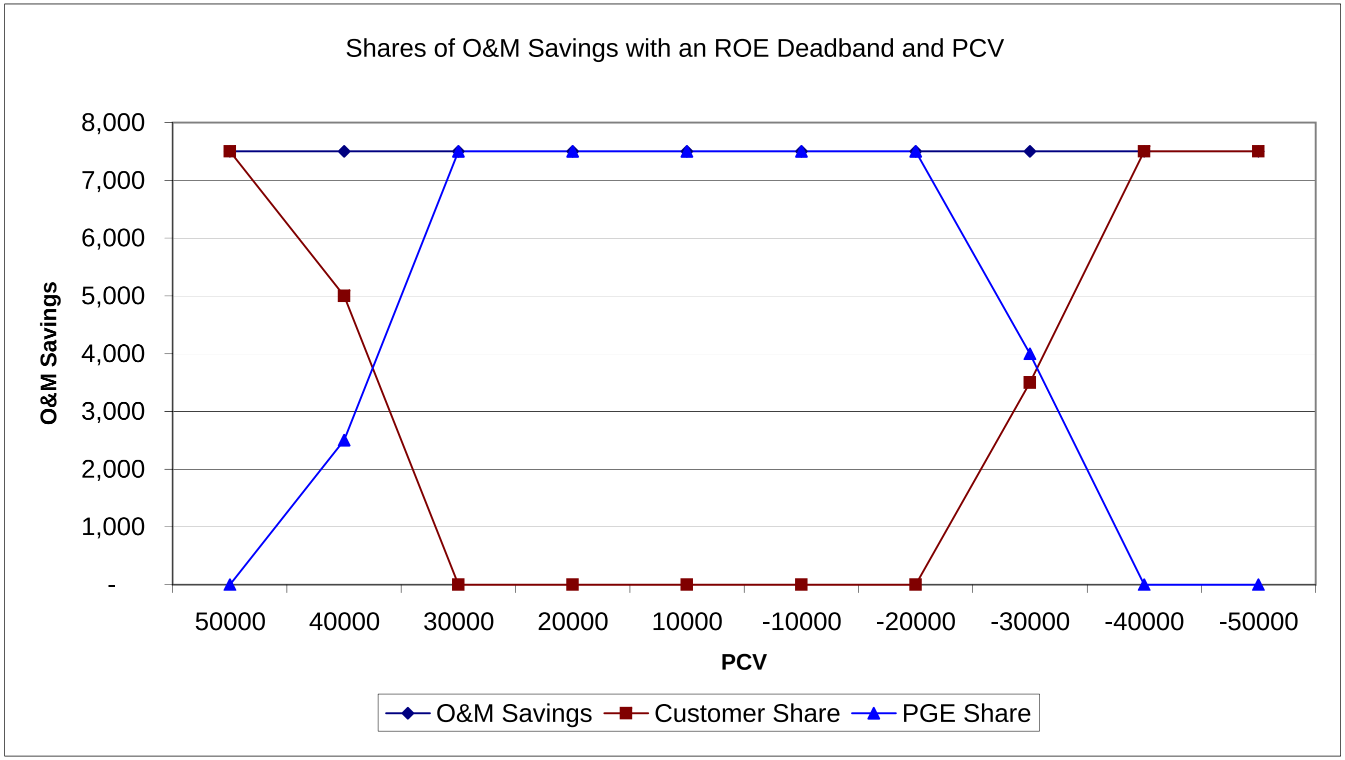
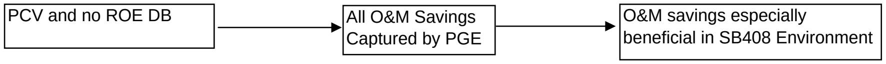
6,000
5,000
4,000
3,000
2,000
1,000
-
O&M Savings ($000)
50000
40000
30000
20000
10000
-10000
-20000
-30000
-40000
-50000
PCV ($000)
O&M Savings
Customer Share
PGE Share


Shares of O&M Savings with an ROE Deadband and PCV
O&M Savings
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
50000
40000
30000
20000
10000
-10000
-20000
-30000
-40000
-50000
PCV
O&M Savings
Customer Share
PGE Share

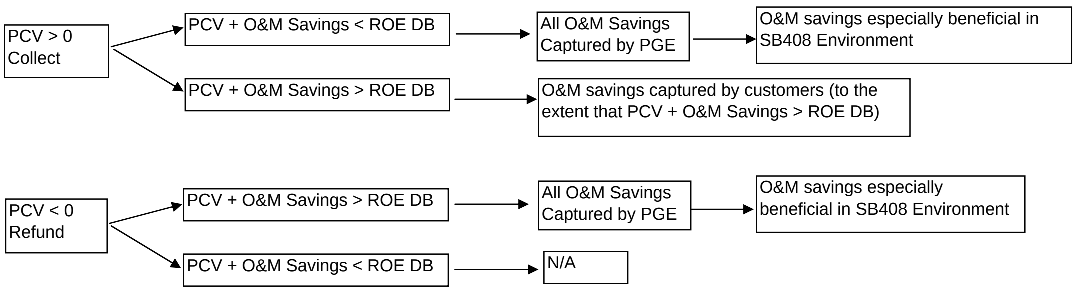
Incentives for O&M Savings with Power Cost Variances and ROE Deadbands

O&M Savings with Power Cost Variance and No ROE Deadband



O&M Savings with Power Cost Variance and an ROE Deadband Beyond Authorized ROE

PCV = Amount Owed to Customers or to be Collected from Customers from PCA



Columns	Rows
A-E	18-26
Requires large O&M savings relative to NVPC Variance	
F-J	18-26
Not Possible	

Summary:

PGE Captures All or part of O&M Savings if:

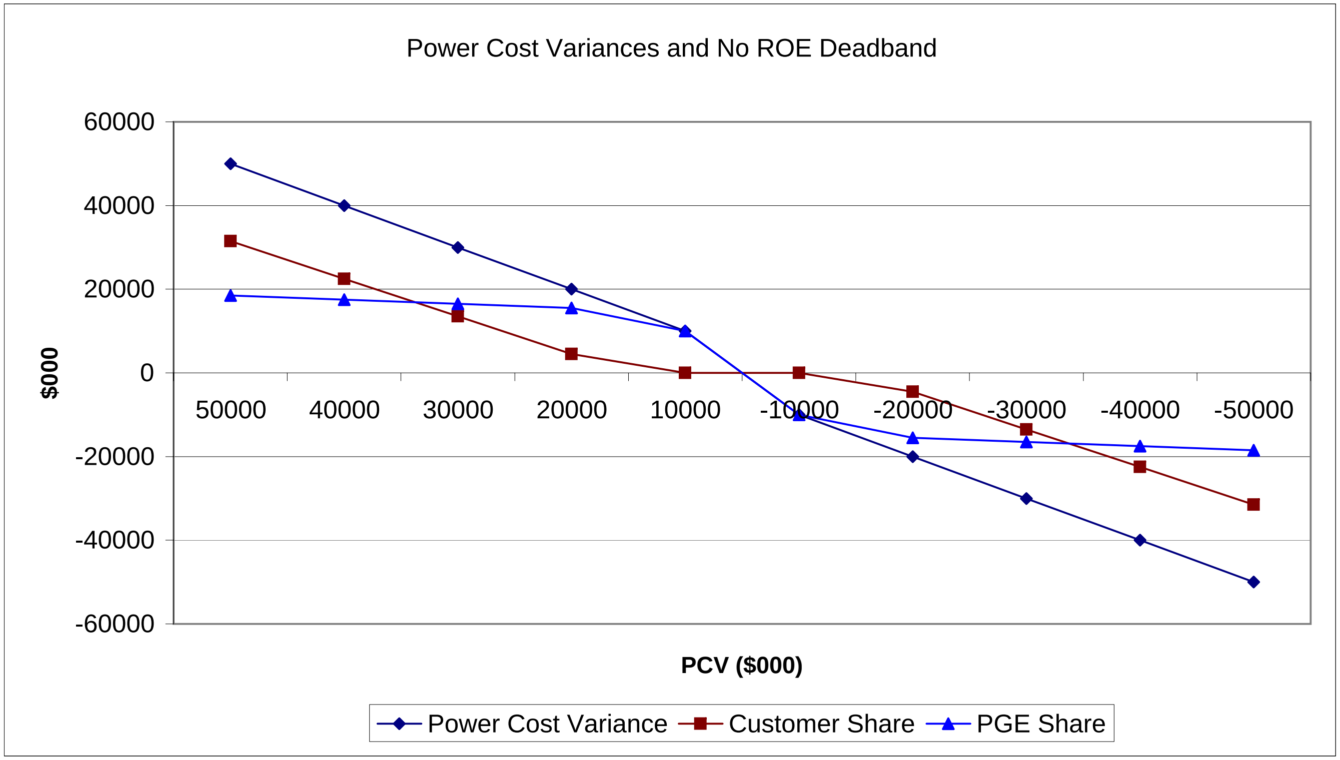
1) The net of collections and O&M savings are under the ROE deadband.
2) The sum of refunds and O&M savings are greater than the ROE deadband.

Customers Capture All or Part of O&M Savings if:

1) The net of collections and O&M savings are outside the ROE deadband.

Examples with Power Cost Variances, Deadbands and Sharing, ROE Deadband, and O&M Savings
($000)

Line No.	Power Cost Variance	(A) 50000	(B) 40000	(C) 30000	(D) 20000	(E) 10000	(F) -10000	(G) -20000	(H) -30000	(I) -40000	(J) -50000
	Scenarios With No ROE Deadband:										
1	PCV Deadband	15,000	15,000	15,000	15,000	10,000	(10,000)	(15,000)	(15,000)	(15,000)	(15,000)
2	PGE Sharing Tier	3,500	2,500	1,500	500	-	-	(500)	(1,500)	(2,500)	(3,500)
3	**PGE Share of Excess PC**	**18,500**	**17,500**	**16,500**	**15,500**	**10,000**	**(10,000)**	**(15,500)**	**(16,500)**	**(17,500)**	**(18,500)**
4	Customer Sharing Tier	31,500	22,500	13,500	4,500	-	-	(4,500)	(13,500)	(22,500)	(31,500)
5	**Customer Share of Excess PC With No ROE Deadband**	**31,500**	**22,500**	**13,500**	**4,500**	**-**	**-**	**(4,500)**	**(13,500)**	**(22,500)**	**(31,500)**
6	Total Excess Power Costs Shared	50,000	40,000	30,000	20,000	10,000	(10,000)	(20,000)	(30,000)	(40,000)	(50,000)
	Scenarios with O&M Savings but No ROE Deadband:										
7	Maximum Collection/(Refund) of Excess PC	31,500	22,500	13,500	4,500	-	-	(4,500)	(13,500)	(22,500)	(31,500)
8	O&M Savings	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)
9	**Maximum Collection/(Refund) with No ROE Deadband**	**31,500**	**22,500**	**13,500**	**4,500**	**-**	**-**	**(4,500)**	**(13,500)**	**(22,500)**	**(31,500)**
10	**PGE Share with No ROE Deadband and O&M Savings**	**18,500**	**17,500**	**16,500**	**15,500**	**10,000**	**(10,000)**	**(15,500)**	**(16,500)**	**(17,500)**	**(18,500)**
11	**Amount of $7.5 Million O&M Savings Captured by Customers**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
12	**Amount of $7.5 Million O&M Savings Captured by PGE**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**
	Scenarios With 50 BP ROE Deadband:										
13	Approximate Revenue for 50 BP of ROE Deadband Beyond Authorized ROE (Based on UE-180 Revenue Requirement With PW)	(8,750)	(8,750)	(8,750)	(8,750)	(8,750)	8,750	8,750	8,750	8,750	8,750
14	Possible Collection/(Refund) of Excess PC	31,500	22,500	13,500	4,500	-	-	(4,500)	(13,500)	(22,500)	(31,500)
15	**Maximum Collection/(Refund) with 50 BP ROE Deadband**	**31,500**	**22,500**	**13,500**	**4,500**	**-**	**-**	**(4,500)**	**(13,500)**	**(22,500)**	**(31,500)**
16	**PGE Share with 50BP ROE Deadband**	**18,500**	**17,500**	**16,500**	**15,500**	**10,000**	**(10,000)**	**(15,500)**	**(16,500)**	**(17,500)**	**(18,500)**
17	Delta ROE from Collection/Refund	-3.60%	-2.57%	-1.54%	-0.51%	0.00%	0.00%	0.51%	1.54%	2.57%	3.60%
	Scenarios with O&M Savings and a 50 BP ROE Deadband Beyond Authorized ROE:										
18	Maximum Collection/(Refund) of Excess PC	31,500	22,500	13,500	4,500	-	-	(4,500)	(13,500)	(22,500)	(31,500)
19	Maximum Collection/(Refund) with 50 BP ROE Deadband	31,500	22,500	13,500	4,500	-	-	(4,500)	(13,500)	(22,500)	(31,500)
20	O&M Savings	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)
21	**Maximum Collection/(Refund) with ROE Deadband**	**31,500**	**22,500**	**13,500**	**4,500**	**-**	**-**	**(4,500)**	**(13,500)**	**(22,500)**	**(31,500)**
22	**PGE Share with 50 BP ROE Deadband and O&M Savings**	**18,500**	**17,500**	**16,500**	**15,500**	**10,000**	**(10,000)**	**(15,500)**	**(16,500)**	**(17,500)**	**(18,500)**
23	Delta ROE from Collection/Refund	-3.60%	-2.57%	-1.54%	-0.51%	0.00%	0.00%	0.51%	1.54%	2.57%	3.60%
24	**Amount of $7.5 Million O&M Savings Captured by Customers**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
25	**Amount of $7.5 Million O&M Savings Captured by PGE**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**	**7,500**
26	Total O&M Savings Shared	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500


Power Cost Variances and No ROE Deadband
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-20000
-40000
-60000
$000
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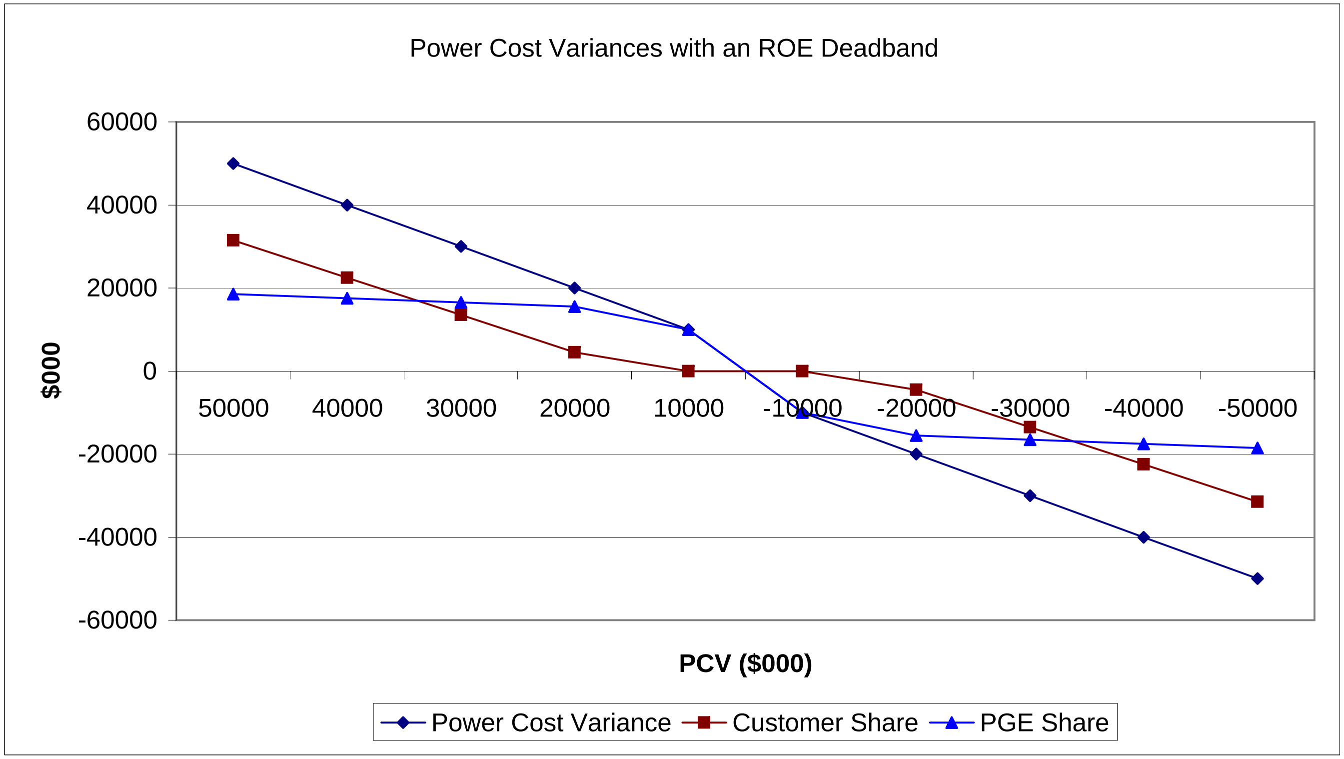
-10000
-20000
-30000
-40000
-50000
PCV ($000)
Power Cost Variance
Customer Share
PGE Share


Power Cost Variances with an ROE Deadband
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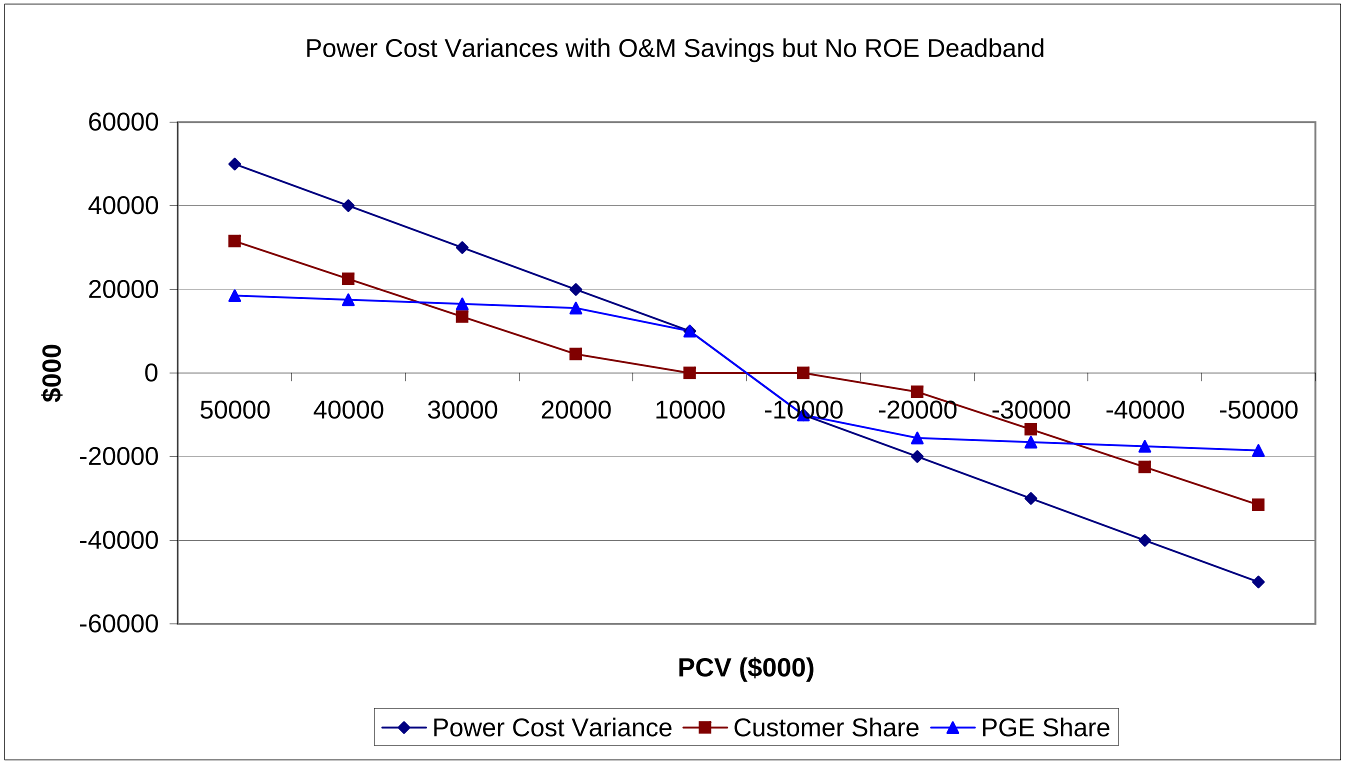
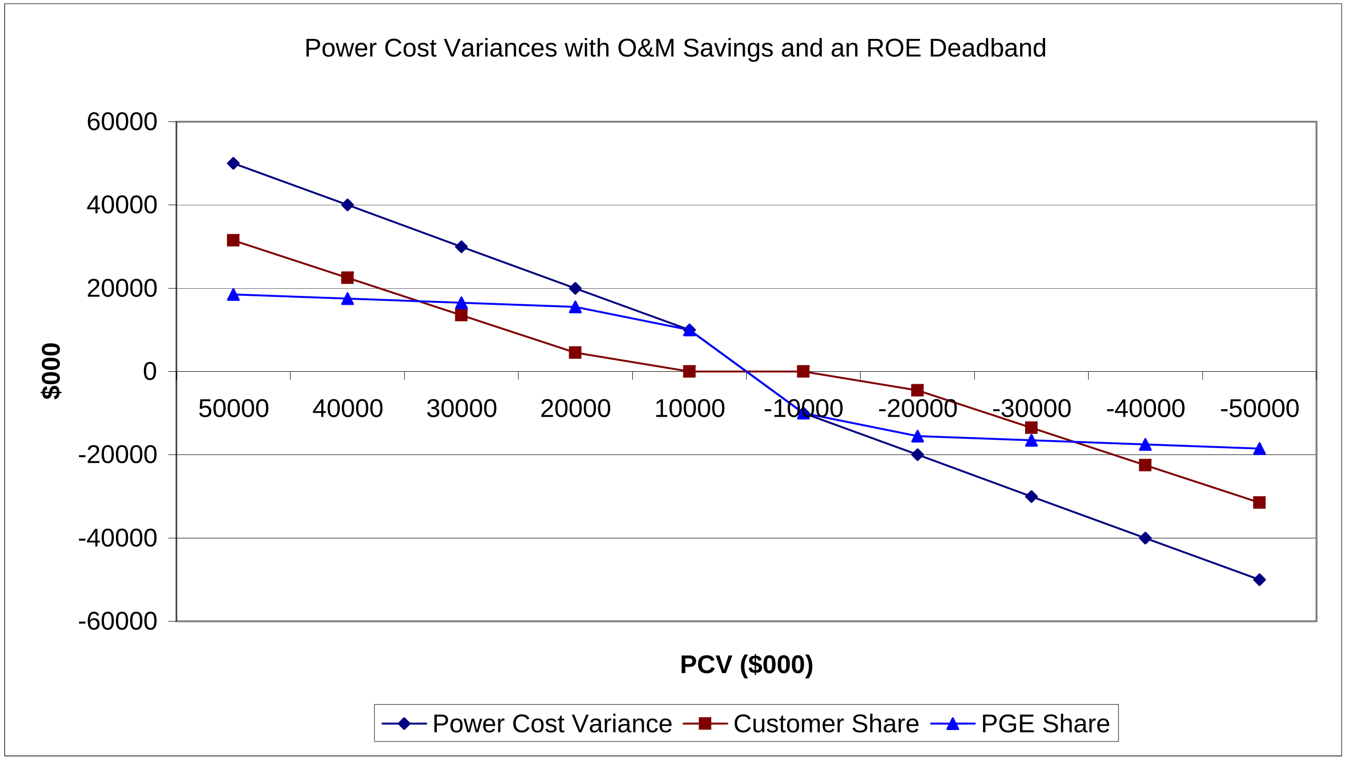
PCV ($000)
Power Cost Variance
Customer Share
PGE Share



UE 180 - UE 181 - UE 184 / PGE Exhibit 2603
Tinker - Schue - Drennan / 5


Power Cost Variances with O&M Savings and an ROE Deadband
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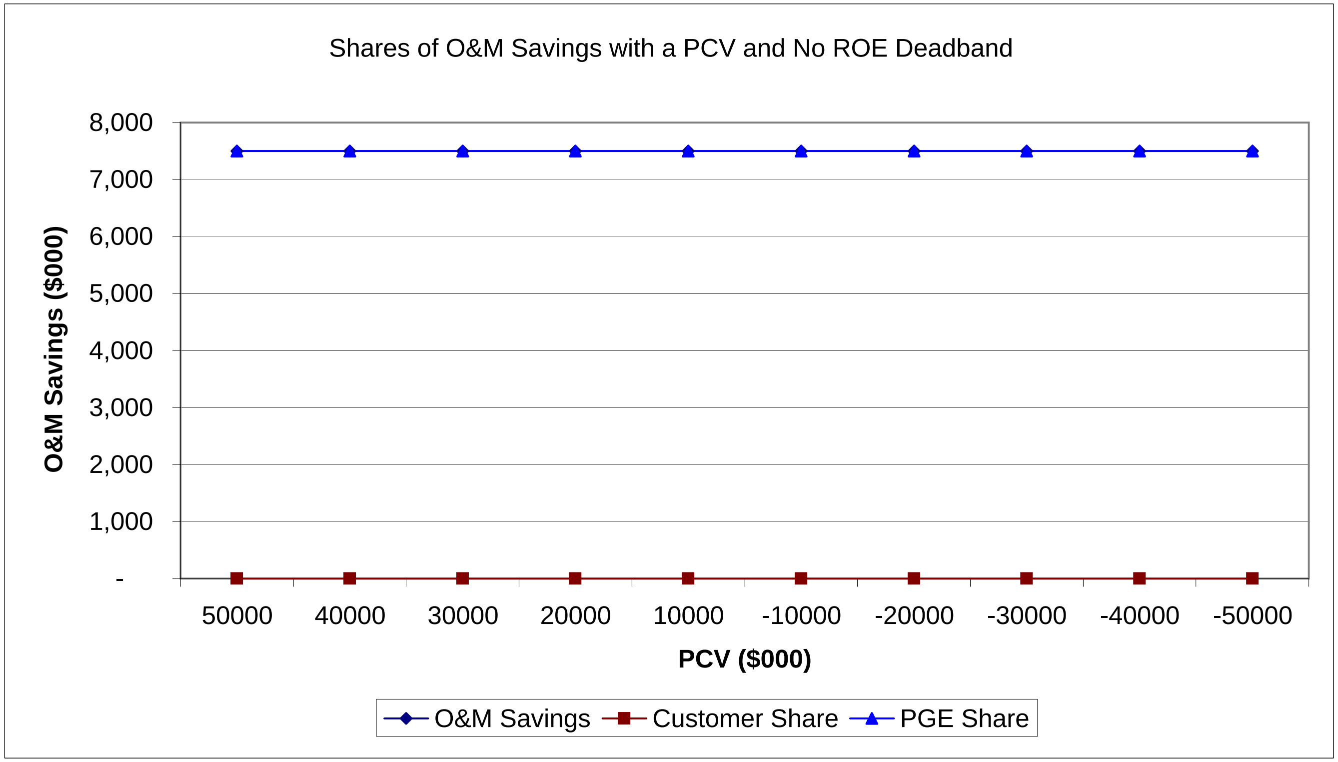
PCV ($000)
Power Cost Variance
Customer Share
PGE Share


Shares of O&M Savings with a PCV and No ROE Deadband
O&M Savings ($000)
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
50000
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-10000
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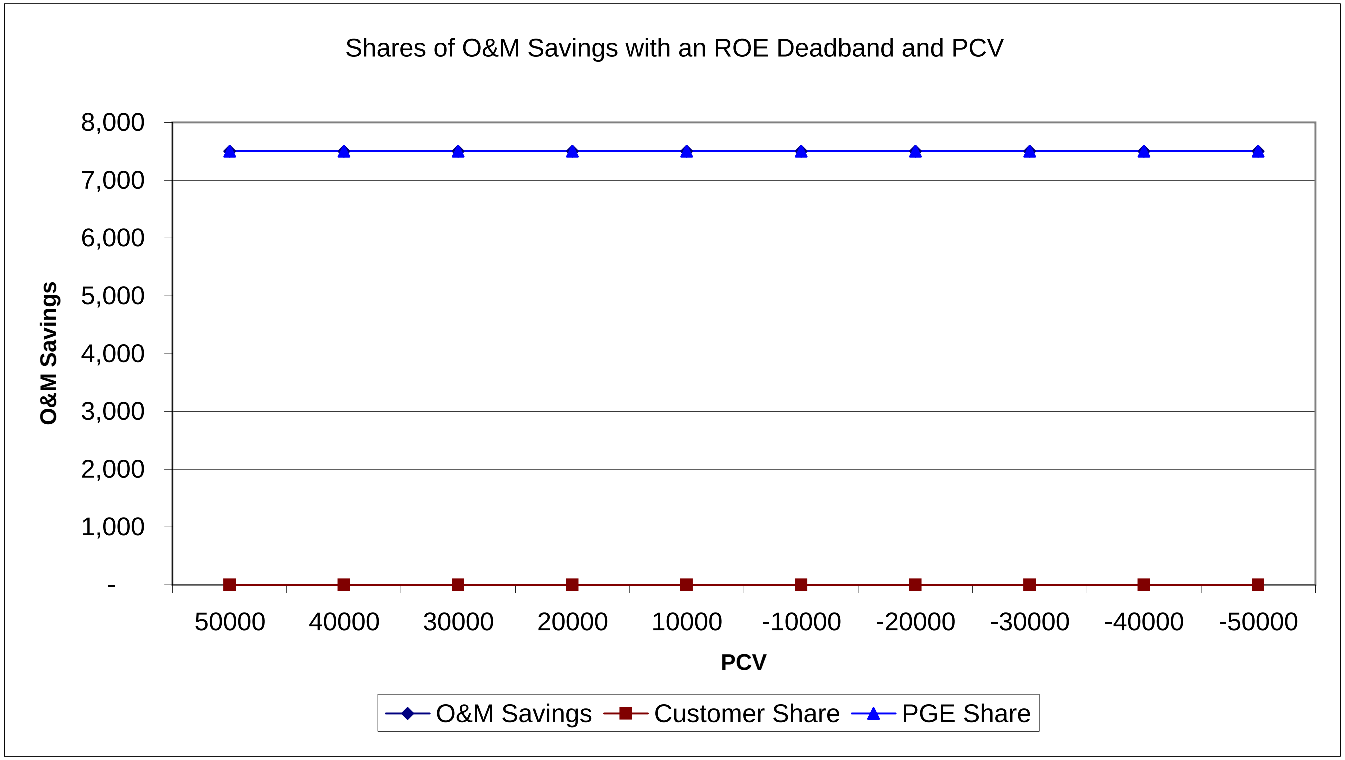
-30000
-40000
-50000
PCV ($000)
O&M Savings
Customer Share
PGE Share


Shares of O&M Savings with an ROE Deadband and PCV
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O&M Savings
50000
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20000
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-10000
-20000
-30000
-40000
-50000
PCV
O&M Savings
Customer Share
PGE Share

SCHEDULE 100
POWER COST ADJUSTMENT

In addition to the rates set forth in the other schedules of this tariff, each Customer's bill will be adjusted to compensate for power costs as they differ from those included in the basic rate schedules. The Adjustment Rate to be applied to each kilowatt-hour sold will include 80 percent of the difference between Average Power Rates and Base Power Rates. This adjustment will be subject to revision every calendar quarter.

APPLICABLE

To all bills for electric service calculated under applicable tariffs.

PROJECTED (OR ACTUAL) AVERAGE POWER RATES

The Projected (or Actual) Average Power Rates are defined as the projected (or actual) total power cost for energy generated and purchased divided by the projected (or actual) total kWh delivered to ultimate Customers. The total power cost will be determined as the sum of the fuel expenses of all Company-owned or leased generating facilities, costs of carrying fuel oil inventories and net results of sales from inventory, the net cost of purchased power, and the cost of transmission of electricity by other systems, less the revenues from sale for resale.

BASE POWER RATES

The Base Power Rates are defined as the quarterly Average Power Rates used to develop existing rate schedules. The current Base Power Rates are:

0.841¢	January through March
0.740¢	April through June
0.561¢	July through September
0.792¢	October through December

POWER COST ADJUSTMENT ACCOUNT

The Company will maintain a Power Cost Adjustment Account to record overcollections and undercollections. The Account will contain the difference between previously authorized power cost revenues and 80 percent of the "power cost variances". The "power cost variances" are the differences between the Actual Average Power Rates and the Base Power Rates times the total kilowatt-hour sales to ultimate customers.

Table of Contents

I. Introduction

Q. Please state your names and positions.

A. My name is Patrick G. Hager. I am the Manager of Regulatory Affairs at PGE. I am responsible for analyzing PGE's cost of capital, including its Required Return on Equity.

My name is William J. Valach. Until the Fall of 2005, I was the Manager of Finance and Assistant Treasurer for PGE. I am now the Director of Investor Relations for PGE. I am responsible for managing the relationships and communications with PGE's shareholders and the investing public.

We are responsible for PGE Exhibits 1100 and 2000. Our qualifications are in our direct testimony, PGE Exhibit 1100, Section VII.

Q. What is the purpose of your testimony?

A. Our testimony responds to the Staff and ICNU-CUB surrebuttal testimony. We provide a brief overview of our position, followed by an update to PGE's cost of debt for 2007 and a response to Staff's updated estimate for PGE's cost of capital. We also respond to Staff's numerous comments on our testimony.

Q. Please briefly summarize your testimony.

A. Our testimony, which is presented in six sections, makes the following points:

- We update the cost of long-term debt by reflecting the issuance of approximately $300 million of new long-term debt in 2007 rather that the $100 million in July 2007 that we had previously forecasted. The effect is to lower both PGE's cost of long-term debt by 10 basis points and PGE's equity ratio to approximately 53%.

- We respond to the cost of capital recommendations of ICNU-CUB witness Gorman.
- We respond to Staff's recommendations regarding capital structure, and show how Staff's recommended 50% equity and 50% debt structure would limit the flexibility necessary for PGE to raise capital to support its large capital expenditures for wind development and hydro relicensing.
- We respond to Staff's "updated" ROE recommendation, which increased from 9.30% to 9.40% without any verifiable explanation.
- We discuss credit metrics and credit ratings, and describe the impact of Staff's recommended 9.40% ROE, which would be the lowest authorized ROE in the country.
- We respond to Staff's testimony regarding our critique of their DCF analyses.
- We respond to the statistical arguments raised by Staff witness Conway regarding our risk positioning analysis.

Q. What is your general response to Staff's testimony?

A. Staff's testimony presents nothing new regarding the merits of our cost of capital analyses.

Staff argues in a number of places that PGE witnesses have mischaracterized or misstated Staff testimony. PGE had no intent to do so; to respond to Staff's Reply testimony, we had to interpret that testimony and any related data request responses. We respond to some of Staff's "mischaracterization" arguments, but not to each one here because the primary purpose of our testimony is to provide the broader view that the Commission must keep in mind in determining cost of capital.

Q. What is the broader view that should be kept in mind in determining PGE's cost of capital?

A. With input from expert witnesses and considering constitutional and statutory standards, the Commission must establish a reasonable cost of capital for PGE as part of ratemaking for the 2007 test year. It is the parties' overall positions that are most relevant to this effort.

First, Staff is recommending the lowest authorized ROE in the country as seen in PGE Exhibit 2706. Staff's recommended ROE is extreme, even when compared to the cost of capital testimony offered by ICNU-CUB, which recommends an ROE that is 50 basis points higher.

Second, Staff's recommended capital structure is now 50% equity and 50% long-term debt which, although a slight increase in equity from their initial position, is still inadequate. PGE faces much more risk than in our previous general rate case (Docket UE 115) and we have a significant capital expenditures program that includes Port Westward, the Biglow Canyon wind farm, hydro relicensing, and potentially AMI. PGE needs to have financing flexibility, which Staff's recommended capital structure will not provide.

II. Cost of Debt Update

Q. Did Staff respond to your comments and conclusions regarding their testimony on PGE's cost of debt?

A. No. Our rebuttal testimony thoroughly explained why the Commission should reject Staff's proposed decrease to PGE's cost of long-term debt. Staff did not respond at all to this rebuttal, although they did raise their estimate of PGE's cost of debt by two basis points, without explanation.

Q. What is your current estimate for PGE's long-term cost of debt in 2007?

A. PGE Exhibit 2701 provides our current estimate of long-term debt. The exhibit shows that we now expect to issue approximately $300 million in 2007 versus the $100 million previously. Specifically, we expect to issue approximately $150 million of 30-year first mortgage bonds in April 2007. The current coupon is estimated to be approximately 6.15%. The coupon consists of the 30-year Treasury of 4.90% and PGE's estimated credit spread of 1.25%. PGE expects to issue an additional $150 million of 10-year first mortgage bonds in August of 2007, with an estimated coupon of 5.77%. The coupon consists of the 10-year Treasury of 4.77% and PGE's estimated credit spread of 1.00%. As a result, our weighted outstanding amount of long-term debt for 2007 has increased from approximately $997.3 million to $1,119 million. In addition, while our cost of debt has declined from 6.83% to 6.73%, because of the higher amount of debt, our weighted cost of debt has increased from 3.00% to 3.14%.

Q. What is the impact on PGE's forecasted capital structure for 2007?

A. As shown in Table 1 below, PGE's capital structure now contains significantly more debt than in our previous estimate. PGE's equity ratio has fallen from approximately 56% in our previous forecast to 53% with our update.

Table 1
PGE's Weighted Cost Of Capital
(Test Year 2007)

Component	Average Outstanding ($000)	Percent of Capital	Cost	Weighted Cost
Long-term Debt	$1,119,050	46.73%	6.73%	3.14%
Preferred Stock	-	-	-	-
Common Equity	$1,275,487	53.27%	10.75%	5.73%
Total	$2,394,537	100.00%		8.87%

We also note that there is a corresponding change in the weighted cost of capital – declining from 9.03% to 8.87%.

Q. Why has your estimate of PGE's cost of debt changed?

A. We now forecast that the Biglow Canyon wind project will come on line by December 31, 2007, moving all of this capital expenditure into 2007. As explained in our previous testimony, PGE's current capital structure supports our near-term capital needs; Biglow Canyon simply became more near-term.

III. Response to Mr. Gorman's testimony

Q. Does PGE have risk comparable to Mr. Gorman's sample companies (ICNU-CUB Exhibit 319, pages 1-2)?

A. No. Mr. Gorman makes his conclusion based on his use of business profile scores published by S&P and a bond rating comparison (ICNU-CUB Exhibit 319, page 1).

Although we agree that these are useful measures in selecting a sample group relatively comparable to PGE, there are additional, company-specific risks that must also be taken into account when recommending a point estimate for ROE and capital structure.

Q. What would these company-specific risks include?

A. We listed several PGE-specific risks that support our need to maintain a higher equity ratio, including our capital expenditures programs and unresolved issues such as litigation and SB 408 (PGE Exhibit 2000, page 31).

Q. How do you respond to Mr. Gorman's claims that your testimony regarding his DCF range and average DCF point estimate is "flawed" (ICNU-CUB Exhibit 319, page 3)?

A. We disagree. We stated that PGE agrees with Mr. Gorman's range for his comparable sample group, which includes the ranges we developed from our DCF model. However, we disagree on developing a point estimate that takes into account company-specific risks. Mr. Gorman believes his sample already does this; we believe that PGE has company-specific risks not included in the sample and, thus, we do not simply take an average.

Q. Mr. Gorman contends PGE should use current market interest rates in determining its capital costs rather than forecasted interest rates (ICNU-CUB Exhibit 319, page 6). Do you agree?

A. PGE agrees that forecasted interest rates are uncertain, to a point. However, we must make reasonable attempts to forecast new long-term debt costs in 2007. PGE used a couple of methods to determine its 2007 new long-term debt costs, including conversations with bankers and using widely published and accepted sources for 2007 expected interest rates. As we have discussed in Section II, we are able to fix the coupon rate on $150 million of new debt at what are essentially current interest rates.

Q. Mr. Gorman also asserts that PGE should have considered alternative years in which retail rates could be in effect as a result of this rate case (ICNU-CUB Exhibit 319, page 6). Do you agree?

A. No. Mr. Gorman's argument is that we should be using a multi-year test period for some items, but a single test year for others. This is inconsistent.

Q. Although Mr. Gorman discusses his DCF results, did he report any other results (ICNU-CUB Exhibit 319, page 4)?

A. No, not in his surrebuttal testimony. However, Mr. Gorman performed analysis on three models, the DCF (9.5%), the Risk Premium (10.4%), and the CAPM (10.4%), which yielded his range of 9.5% to 10.4% (ICNU-CUB Exhibit 300, page 28).

IV. Capital Structure

Q. How does Staff support its revised capital structure recommendation?

A. Staff argues that:

- PGE had and continues to have "excess capital."
- PGE's documents show that we expect our 2007 capital structure to be 50% equity.
- Their estimate for PGE's capital structure in 2007 is not a "recommendation" that needs to be followed by PGE.
- Staff's recommended ROE is within the range of other authorized ROEs using a "leveraged Beta" approach.

Q. Do you agree with Staff's arguments on these points?

A. No. We address each argument in turn below.

A. PGE Does Not Have Excess Capital

Q. Do PGE's 2005 and 2006 financing plans support Staff's conclusion that PGE has "excess capital"?

A. No. Staff cites PGE's April 2005 Financing Plan as well as the November 3, 2005, 2005-2006 Financing Plan as their support, but nowhere in these plans does PGE use the term "excess capital." In other words, what Staff described as "excess capital," our 2006-2007 Financing Plan states will be used for upcoming capital projects, including the Biglow Canyon wind project and AMI.

Q. How does Staff define "excess capital"?

A. Staff's definition of excess capital is all of PGE's net income from 2002 through 2007 that was not paid to Enron as a dividend. In response to a data request, Staff stated that it "did not assign a specific meaning" but that "excess capital" should be construed in its "normal accounting sense" and further that excess capital included "short-term corporate cash that could have provided the support for a dividend payment to balance PGE's capital structure" and that the term is meant to include "the net income generated by PGE's operations that were not being sent to Enron as dividends."[1]

Q. Do you agree that this is the proper definition of "excess capital"?

A. No. Staff's definition implies that PGE should not have increased its equity during this period of significantly increasing risk in the financial and wholesale energy markets. This is neither rational nor prudent. This definition also overlooks the fact that maturing PGE long-term debt helped drive our equity ratio higher during 2001-2003. This effect was temporary, however. PGE subsequently issued approximately $250 million of long-term debt in 2002.

Q. Did Staff quantify this "excess capital"?

A. No. We asked Staff to quantify the amount of PGE's "excess capital" during the period, by year, if possible. They could not provide an estimate of PGE's "excess capital" for any time during the 2001-2007 period.

B. PGE Expects Its Equity Ratio to Be 50% - *in the Long- Run*

Q. Does PGE's "road show" presentation support Staff's conclusion that PGE has "represented to the financial community a capitalization ratio that is significantly different" than the one proposed for 2007?

[1] Staff responses to PGE data requests are PGE Exhibit 2703.

A. No. The road show presentation presents a 2007 equity ratio for PGE of 50%, but explains in a footnote that the 50% equity assumes that AMI and the Biglow Canyon wind project are financed entirely in 2007. Although we have updated this case with the assumption that we will finance all of Biglow Canyon in 2007, it does not appear that AMI will be completely financed in 2007 as the presentation assumed.

C. Staff's Proposed Capital Structure, If Adopted, Would Have an Adverse Impact

Q. Staff states that they are not "recommending" a capital structure for PGE and that PGE is "free to optimally manage its capital structure going forward subject to conditions it agreed to in UM 1206" (Staff Exhibit 1400, page 8). Is Staff correct?

A. No. Staff is recommending a capital structure for PGE which, all else equal, will not provide compensation for any additional equity in its capital structure beyond what the Commission authorizes. For example, if the Commission authorizes a 50% equity, 50% long-term debt capital structure for PGE, and assuming PGE maintains its current expected capital structure of 53% equity and 47% debt, then PGE would receive the appropriate equity return only on the first 50% of its capital structure. It would receive only the authorized long-term debt return on the remaining 3%. Thus, PGE is penalized by the lower return for any equity above the 50% recommended by Staff.

Q. But isn't PGE "free" to manage its capital structure as Staff testifies?

A. No. Staff ignores the reasons we need higher equity in our capital structure. We discussed the reasons why PGE needs a higher equity ratio in both our direct and rebuttal testimonies. There are business reasons, such as maintaining our financial strength, offsetting the debt equivalence of purchased power contracts, and maintaining access to the capital markets at reasonable rates. In addition, there are specific circumstances when PGE needs to maintain a higher equity ratio. We noted that PGE must be able to maintain liquidity for unexpected margin calls as wholesale power prices fluctuate as well as for unresolved issues including litigation and SB 408. Finally, as we discussed above, we need to maintain the higher equity because we expect large capital expenditures for wind development and for hydro relicensing.

D. Staff's ROE Adjustment to Reflect PGE's Capital Structure Is Flawed and Unsupported

Q. Does Staff provide support for their argument that the Commission should reduce PGE's authorized ROE if the authorized capital structure contains more equity than the average?

A. No. Staff bases their argument on an adjustment the Commission made in 2001. The situation today, however, is quite different. PGE has considerably more risk than in 2001, and, thus, should have more equity than the average electric utility. Staff calculated its reduction using a UE-115 analysis by Mr. Rothschild, which Staff did not update for recent information and from which Staff used the bottom of the range (*i.e.*, 4 basis points for each one percent increase in the level of common equity in the capital structure) rather than the top (13.8 basis points) or even the midpoint (8.7 basis points). Using either the midpoint or the top of the range would have lowered Staff's proposed ROE not to 9.1%, which is already extremely low, but to a figure in the mid- to high 8 percent range. This is so low as to lack credibility.

Q. Does Staff's CAPM "leveraged Betas" analysis show that Staff's recommended Required ROE (RROE of 9.4% is comparable to other authorized ROEs recently granted (Staff Exhibit 1400, pages 10-15)?

A. No. Even assuming that the Commission will entertain a CAPM analysis after concluding in UE 115 that CAPM did not provide supportable or reasonable results, the Commission should reject this CAPM analysis. Staff does not identify the utilities from which it derived the assumed Beta of 0.85 nor how it combined those utilities' data, such as by simple or weighted average. Staff also does not explain why or how it selected 16 regulatory decisions from the over 42 decisions in 2005 and 2006. Finally, Staff uses Mr. Gorman's market risk premium but not his sample or his Betas.

V. Staff's DCF Updates Cannot Be Fully Verified

Q. Does Staff describe how it updated its ROE recommendation from 9.30% to 9.40%?

A. No, not really. Staff identifies updating the Value Line and "reported growth" information, removing two companies (WPS Resources and Empire District Electric), and using more current stock price information (Staff Exhibit 1400, page 2), but whether it was expert judgment or models/methods that produced a higher estimate is not clear. Staff's table at Staff Exhibit 1401 shows an "internal rate of return" of 9.43%, but this figure is not identified as the basis for Staff's 9.4% recommendation.

We could not reconcile the earnings growth and dividend growth with published information. Staff uses the incorrect "Book Value per Share" data from Value Line. The model indicates that Staff used the estimate for 2004-2006 when they should have used the estimate for 2005-2007. Second, although Staff stated that they updated the earnings growth data from Zacks, Kiplinger, Reuters, and Value Line, we could not verify these data with the sources Staff states they used. PGE Exhibit 2704 presents Staff's figures used in their models and the correct figures they should have used. Staff's updated DCF model may contain incorrect estimates for these parameters and, thus, the update may also not be valid. We continue to disagree with Staff's model.

Q. Did Staff consider any other suggestions made by PGE regarding its DCF model?

A. No. Although both Dr. Zepp and we pointed out errors or omissions in Staff's DCF model, Staff did not address them. Staff did run a sensitivity analysis using a "vs" growth term, but did not take this result into account when reporting its range of ROE estimates or its point estimate. We do note that the impact of "vs" growth is a 50 basis point increase from its point estimate in Staff Exhibit 1000 of 9.30%, which is also the same increase Dr. Zepp calculated in his rebuttal testimony.

Q. Does Dr. Hadaway's testimony in Docket UE 170 support the use of spot prices in Staff's model, as Staff suggests?

A. No. Dr. Hadaway's testimony states that his preference is to use a three-month average price, not a spot price.

VI. Credit Metrics and Credit Ratings

Q. Do PGE and Staff agree on the major factors that the credit rating agencies review in rating companies?

A. Yes, in general. We agree that:

- the major credit rating agencies consider a company's financial ratios as an indication of its ability to pay back the debt that it's borrowed.
- the rating agencies consider additional factors, including regulatory environment.
- Oregon's regulatory environment is not as favorable as it has been in the past, given the most recent regulatory reports from Moody's, Standard & Poor's (S&P), and Fitch provided as PGE Exhibit 2705.

Q. What PGE analyses regarding the financial ratios and other factors used by the credit agencies did Staff address in its surrebuttal testimony?

A. Staff addressed our rebuttal testimony that Staff's recommended ROE and capital structure would move PGE closer to a downgrade, using S&P's published financial criteria. Staff agrees with our numerical analysis but disputes the conclusion by claiming that the analysis was only for one year and that the credit rating agencies take into consideration more than just the financial ratios.

Q. How do you respond to Staff's comments?

A. Staff's interpretation of our testimony is unfounded (Staff Exhibit 1400, pages 18-19). Although PGE agrees with Staff that "credit ratings are not based on a single year's expectations" (Staff Exhibit 1400, page 16), the test year established in a general rate case is not necessarily in place for just one year. The outcome from PGE's last general rate case has been in place for five years. Thus, our analysis using the 2007 test year demonstrates the negative effects that Staff's recommendations are likely to have over time as the rates set in this proceeding remain in effect.

We agree with Staff that the financial ratios are not the sole determinant of credit ratings (Staff Exhibit 1400, pages 17-18) and we did not say otherwise. When we perform the financial analysis, we must hold all else constant and look only at the factors that are under study. In our case, those factors were Staff's cost of capital recommendations. Given those recommendations, we calculated the appropriate financial ratios and found that PGE's ratios would be closer to the bottom of the range for most ratios and would be below the range for the debt ratio.

Q. What effect would Staff's recommended 9.40% ROE have on PGE's credit ratings?

A. Financially, the effect would not be significantly different from the analysis we provided in our rebuttal testimony using Staff's recommended 9.30%. The more important impact is likely to be how S&P would view Oregon's regulatory environment. S&P's most recent report on PGE (September 25, 2006) states that one of the reasons for the negative outlook is "an uncertain regulatory environment" and that "[w]eak financial performance could lead to lower ratings, particularly if it is the result of inadequate rate relief." If the Commission adopts Staff's recommended 9.40% ROE, which would be the lowest authorized ROE in the country, credit rating agencies would likely conclude that Oregon has become a more difficult regulatory environment.

Q. Are you implying that credit ratings depend only on authorized ROEs?

A. No. We've already discussed the various financial and other factors that we believe the financial credit agencies consider when they evaluate a company. The agencies would certainly note, however, that 9.40% is over 100 basis points lower than the 10.5% ROE authorized for PGE five years ago, when it didn't face as much risk. They would also note that the 9.40% is over 50 basis points lower than that received by PacifiCorp in a very recent decision.

Q. Staff argues that credit ratings do not determine a company's ability to access capital markets (Staff Exhibit 1400, page 18). Do you agree?

A. No. Credit ratings play an important role in a company's ability to access the capital markets. It is true that a downgraded company may still access the capital markets, but it becomes more difficult and more costly. A lower credit rating implies a higher cost of capital and generally implies a narrower market for the company's securities and sometimes less liquidity for the securities.

Q. Staff states that as long as a company has an investment grade rating, the "capital attraction standard" is met (Staff Exhibit 1400, page 18). Is this a fair statement?

A. No. Oregon has never adopted such a capital attraction standard and should not for two reasons.

First, as defined by the Hope and Bluefield decisions, a "utility is entitled to earn a return that will allow it to maintain its credit so that it continues to have access to the capital markets" and a return that is "sufficient to assure confidence in its financial health so it is able to maintain its credit and continue to attract funds on reasonable terms" (Morin, Roger A., <u>Regulatory Finance</u>, Public Utilities Reports, Inc 1994, at 10). An "investment grade" standard is the absolute minimum standard for being able to access capital, and may be insufficient to provide assurances of financial health or enable the attraction of capital on reasonable terms.

Second, most of the entities with corresponding risks with which PGE is competing for access to capital obviously have credit ratings that are superior to the minimum "investment grade" standard.

VII. Response to "Errors in Theory and in the DCF Model"

Q. Does Staff correctly characterize PGE's rebuttal argument regarding documentation when Staff asserts that "without maintaining a file with current reports, witnesses cannot rely on their existing knowledge base without the risk of being personally attacked" (Staff Exhibit 1400, page 25)?

A. No. PGE Exhibit 2020 provides the relevant data requests and Staff's responses. Staff cited evidence for their statements in their testimony and we asked for that evidence. Staff replied that the evidence was their judgment or expertise. Staff can rely on its expert judgment or expertise, as would any expert witness. But Staff cannot claim that they have evidence for a statement and then not provide it when asked.

Q. Did you state that "Staff's opinions are less valuable than those of 'outside experts'"?

A. No. We stated that "Staff in many cases had no evidence and it was indeed Staff's opinion, which is accorded less weight than if supported by the opinions or analyses of outside experts" (PGE Exhibit 2000, page 47). Our statement would apply to ourselves or any other witness – expert opinions have more weight when supported by other outside experts, studies, or information.

Q. Did Staff's surrebuttal testimony provide evidence for their statements in their testimony?

A. Yes, Staff cited several passages in Staff Exhibit 1003. This is the information that we were seeking via data request and had Staff responded earlier, we would have incorporated it into our analysis.

Q. Is the Dr. Woolridge presentation Staff cites relevant to your testimony that other commissions have authorized more than 10% for RROE?

A. No. Dr. Woolridge apparently made this presentation at a conference over three years ago. These decisions were all in 2003, when interest rates were much lower, and were primarily for distribution-only utilities in the Northeast. Because the information contained in the presentation is out of date and for non-comparable utilities, it is basically useless. Dr. Zepp provides additional reasons for discounting Woolridge's three-year old presentation.

VIII. The Risk Positioning Method (Again)

Q. Before responding to Staff's arguments regarding PGE's Risk Positioning Method, please briefly describe it.

A. The Risk Positioning method is a very simple linear regression that posits that authorized ROEs, in the form of a risk premium over Treasuries, are a function of interest rates. We used historical data to estimate the risk premium over Treasuries that investors would expect. Because investors buy stock in the utilities we include in our model, we believe that it is reasonable to assume that the authorized ROEs in these contested decisions accurately include an appropriate risk premium. We hypothesize that the risk premium can be modeled as a function of the interest rates, *i.e.*, a relationship (or correlation in statistical terms) exists between the two. In fact, other analysts before us have found the same inverse relationship between the risk premium and the interest rate that we do[2], giving our model some credence. We found that our simple model explains over 50% of the relationship between the risk premium over Treasuries (*i.e.*, authorized ROEs minus Treasuries) and the interest rate. Given this, one can assume that the interest rate is a key (important) element of the contested authorized ROE decision.

If a model explains well, then it will generally forecast well, given similar circumstances. This is not open to dispute. Rather the issue is whether the model can be used for predictive purposes. For instance, an historical model based on proprietary

2 Brigham, E. F., D.K. Shome, and S.R. Vinson, 1985, "The Risk Premium Approach to Measuring a Utility's Cost of Equity," Financial Management (Spring), 33-45.
Harris, R. S., 1986, "Using Analyst's Growth Forecasts to Estimate Shareholder Required Rates of Return," Financial Management (Spring), 58-67.
Harris, R. S. and F.C. Marston, 1992, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," Financial Management (Summer), 63-70.
Maddox, F. M., D. T. Pippert, and R. N. Sullivan, 1995, "An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry," Financial Management (Autumn), 89-95.

information that is unavailable for the future cannot be used. It explains the past but cannot predict the future. The inputs to our model are freely available through public data sources.

The Risk Positioning method is one form of the Risk Premium model that is used in many regulatory jurisdictions in the U.S. While the Risk Premium model simply calculates the differences between Treasuries (or Bonds) and authorized ROEs, the Risk Positioning method performs a simple linear regression between the two variables. What we found, and have confirmed throughout this docket, is that this very simple model has a strong theoretical basis, explains a significant portion of the risk premium, and has good to excellent statistics.

Q. What are Staff's major concerns regarding the Risk Positioning Method?

A. The concerns Staff raises on surrebuttal are the same as Staff raised in their Reply testimony. These are that:

- the data set has
    - no logical grouping
    - does not lend itself to statistical testing.
- the model
    - omits relevant variables
    - lacks a theoretical underpinning
    - isn't a good predictive model
    - provides fallacious statistics.

We address each of these concerns below.

A. The Data Set

Q. Why does Staff conclude that the Risk Positioning data set has no "logical grouping?"

A. Staff bases this conclusion on our response to their data requests that PGE did not perform statistical testing for heteroskedasticity and autocorrelation on the Risk Positioning Model.

Q. What are heteroskedasticity and autocorrelation and why didn't PGE test for them?

A. Heteroskedasticity tests would establish whether there is a change in the variance of the data across groups, in this case regulatory jurisdictions. As we noted above, we do not have data for all or for a significant set of regulatory jurisdictions over any monthly period. Thus, there is no reason to test for heteroskedasticity.

Autocorrelation tests whether the results today are correlated with results of yesterday (for the same group). Given that we do not have authorized ROEs for each month in a particular regulatory jurisdiction, this test would also be inappropriate. Neither test would offer results that would have any significant interpretation.

Q. Does not performing these tests mean that the data lack any "logical grouping" or that the data set is "so limited that statistical testing would be meaningless " (Staff Exhibit 1300, pages 7-8)?

A. No. There is a very obvious logical grouping – authorized ROEs by jurisdiction for any particular month. And we performed several tests on our data and model. When we constructed the model almost 10 years ago, we performed the standard statistical tests that one would expect when using an ordinary least squares regressions. These tests are fairly standard in most econometric or statistical packages and include R^2, R^2-adjusted, F-statistic, and t-statistic. We also tried to determine the appropriate lag for interest rates by examining the output from our regressions. As we noted before, we found that the appropriate lags were 1- and 8-months. We did not keep our initial results.

Subsequently, as a result of Staff's concerns regarding the appropriate lags, we tested the model using the AIC and BIC tests that we described in our rebuttal testimony. We found that both the 7- and 8-month lags performed the best, although the 7-month lag was slightly better. Consequently, we now use the 7-month lag in our regression. We continue to use the 1-month lag in another regression equation because the differences in the AIC and BIC tests were very small.

Q. If Staff is concerned with the possibility of heteroskedasticity and autocorrelation, could Staff have performed these tests?

A. Yes. Staff used a statistical program call SHAZAM, which has the capability to test for these potential problems. However, Staff did not perform these tests, although we supplied them with the data and the programming code for our regressions.

B. The Risk Positioning Model

1. Omitted variables

Q. Why is Staff's concern with omitted variables unfounded?

A. All regression equations omit variables. The relevant questions are the importance of the omitted variables and whether their omission would introduce potential bias into the equation. Our Risk Positioning Model is simple and explains a significant portion of the variance in authorized ROEs (or the risk premium between Treasuries and authorized ROEs). We saw no need to introduce additional variables. Staff continues to assert that PGE has mis-specified its model by omitting variables, but does not specify which variable or variables should be included. If Staff believed that our regressions should include additional variables, they could have easily included one or more of these variables and performed their own analysis.

<u>2. Theoretical underpinning.</u>

Q. Is Staff's suggestion that your model lacks sound theoretical underpinnings well founded?

A. No. We agree with Staff that a model should be developed from a sound, defensible theory. This is exactly what we did; we did not advocate a model that is a single variable model, as Staff suggests. We established a hypothesis regarding interest rates and authorized ROEs; we then tested our hypothesis, and verified our results. Once we had determined that interest rates were the most important variable, we limited our analysis to one variable. We also considered a derivative form of the relationship, and then tested and verified it as well. Staff cites Peter Kennedy regarding the search for a correct set of explanatory variables (Staff Exhibit 1300, page 13). Mr. Kennedy's process directly corresponds to the one used by PGE in its model specification.

<u>3. The Risk Positioning Model is a good estimator.</u>

Q. Is Staff correct that PGE failed to test the predictive power of the Risk Positioning Model?

A. Yes, because we do not present the model as a predictor of ROE. PGE did not present the model to predict a point ROE. The regression model can be used to forecast a general risk premium, and hence a general authorized ROE, but the analyst would obviously have to make their own regulatory jurisdictional adjustments to that general estimate. For example, the results of our Risk Positioning model forecast an authorized ROE that closely corresponds to that of recently authorized decisions, unlike the suggested levels of Staff. The forecast will differ from the actual authorized ROE in a contested case and the analyst should make whatever adjustments he deems necessary based on evidence and experience.

Staff's argument that AIC and BIC test goodness of fit and not predictive power misunderstands the nature of goodness of fit. If underlying assumptions do not change significantly, a model that has a good fit will also predict well. The key is the underlying assumptions.

Q. Does Staff's argument about PGE's AIC and BIC tests correctly characterize those tests?

A. No. It appears that Staff misunderstands the tests. AIC and BIC offer information that allows the analyst to compare one model to another and make a reasoned judgment. The tests do not offer information about the models independent of other models. Simply put, the AIC and BIC offer a useful measure *across* models. Further, as we noted in our rebuttal testimony, these tests are an operational way of trading off the complexity of an estimated model against how well the model fits the data. Both are widely accepted in model estimation, particularly when examining lag structure. See Akaike, Hirotsugu. <u>Information Theory and an Extension of the Maximum Likelihood Principle</u>.

Furthermore, Staff takes quotes completely out of context in Staff Exhibit 1300, page 6, lines 8-17. This discussion relates to the use of AIC for model specification purposes and was not a discussion of theory. Staff also incorrectly notes that PGE only used a single lag—rather multiple lags were examined and subsequently rejected for both theoretical and practical reasons.

<u>4. Model statistics are solid.</u>

Q. How does Staff attempt to prove that PGE's model results are fallacious?

A. Staff uses the random variable model from their response testimony, changing only the foundation (from an Excel spreadsheet to SHAZAM, a statistical package commonly used in universities) and using random variables between the numbers one and ten rather than between 0 and 1. These changes still do not support the conclusions Staff attempts to draw because the theory behind the two models is different. Changing the range of the random variables does not change the result. Staff's random number model does not explain anything; the Risk Positioning Model has good explanatory power. (PGE Exhibit 2000, pages 60-61).

Using a simply analogy, we both hypothesize that we are modeling meatloaf. We start from two variables: meatloaf and meat (authorized ROE and interest rate). We hypothesize that you need meat and other ingredients, such as bread crumbs, to make a meatloaf. However, the primary ingredient in meatloaf is meat. Our model simply states that the amount of meat required for the meatloaf is a function of the amount of meatloaf that you wish to make. You need lots of different ingredients to make a meatloaf, but if you know the amount of meat that will be included, you generally have a pretty good idea how big the meatloaf will be.

Staff also starts from two variables, bread crumbs and parsley. Although Staff adds these and calls it "meatloaf", this designation overlooks that the primary ingredient - meat -

is missing. The unrelated elements will not make a meatloaf without the omitted variable (meat).

Our model includes the primary ingredient; Staff's does not. This is why the results of the two do not match.

Q. Please address Mr. Conway's concern that the t-statistics and R^2 between the two models proposed by PGE are different.

A. Although Staff continues to raise this issue (Staff Exhibit 1300, page 17), we fully addressed it in the Technical Appendix to our rebuttal testimony (PGE Exhibit 2000). The statistics will <u>not</u> be the same, nor should they be. The models are specified slightly different. The point is that the estimates are the same for both forms of the model. The correct t-statistics and the correct R^2 (as identified by Staff) are readily available in the alternate form of the model. Because both forms of our model yield the same estimate, it doesn't matter which form of the model is used. We chose to use the form we did because we wished to explicitly model the risk premium. If Staff prefers the alternative form of our model, we can use that as well – the estimates will be the same.

IX. Conclusion

Q. Please summarize your testimony.

A. PGE is requesting an ROE of 10.75% in this proceeding, which is supported by DCF and Risk Positioning analyses, and is very much in line with ROEs being authorized for other electric utilities across the country in 2006. In this testimony, we also update PGE's long-term debt to reflect an increase in the amount of debt to be issued in 2007; this update results in a lower equity ratio (53.3%), a lower average cost of debt (6.73%), and an overall cost of capital of 8.87%, which is a 16-basis point reduction from that requested in our direct testimony. This overall rate of return will be sufficient to ensure confidence in PGE's financial integrity, to allow PGE to maintain its existing credit rating and to attract capital on reasonable terms, all as required by Oregon statute. This is vitally important, given the capital that PGE will be raising in the coming years to support the acquisition of generating resources to provide an economical power supply for our customers over the long term.

In contrast, Staff is recommending an overall rate of return of 7.86%, which is 30 basis points lower than recently authorized for PacifiCorp in Docket UE 179 and 44 basis points lower than the 8.30% overall return recommended by ICNU-CUB in this proceeding. Staff's recommended ROE of 9.4%, if adopted, would represent the lowest authorized ROE for any electric utility in the nation, and would send repercussions throughout the financial community that would likely lead to a credit downgrade and seriously jeopardize PGE's access to necessary capital. Staff combines its punitive ROE recommendation with an unsupported disallowance of long-term debt costs and a proposed capital structure that fails to reflect PGE's circumstances, such as our reliance on purchased power and the debt imputation associated with this reliance. Staff's position on cost of capital is so extreme as to strip it of any credibility, and should be accorded little, if any, weight.

Given the capital that will be raised based on the financial metrics that are produced by the outcome of this case, the Commission's decision will have capital cost impacts for many years in the future. PGE's requested rate of return will ensure that PGE is able to access capital on reasonable terms, which is in the best interests of our customers over time.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
2701	Cost of Long Term Debt
2702	Weighted Cost of Capital
2703	Staff Responses to PGE Data Requests
2704	Staff’s Updated DCF Inputs vs. Actual Updated DCF Inputs
2705	Recent Regulatory Reports from Fitch, Moody’s, and S&P
2706	Updated Authorized ROEs

Cost of Long-Term Debt

December 31, 2007

Description (C)	Issue Date (D)	Maturity Date (E)	Term (F)	Coupon (G)	Gross Proceeds (H)	DD&E Issue Costs (I)	Call Premium & Unamort. DD&E of Refunded Issue (J)		Net Proceeds (K) [H-I-J]	Embedded Cost (L)	Net to Gross Rate (M)	Face Amount Outstanding (N)	Net Outstanding (O) [M*N]	Face Amount Weight (P) [N/Total]	Weighted Rate (Q) [P*L]
5.6675% Series	28-Oct-02	25-Oct-12	10	5.668%	$100,000,000	$12,217,227	$0		$87,782,773	7.420%	87.783%	$100,000,000	$87,782,773	8.936%	0.663%
5.279% Series	08-Apr-03	01-Apr-13	10	5.279%	$50,000,000	$4,209,517	$0		$45,790,483	6.434%	91.581%	$50,000,000	$45,790,483	4.468%	0.287%
5.625% Series	04-Aug-03	01-Aug-13	10	5.625%	$50,000,000	$408,842	$1,946,809		$47,644,349	6.266%	95.289%	$50,000,000	$47,644,349	4.468%	0.280%
6.750% Series	04-Aug-03	01-Aug-23	20	6.750%	$50,000,000	$521,342	$1,946,809		$47,531,849	7.220%	95.064%	$50,000,000	$47,531,849	4.468%	0.323%
6.875% Series	04-Aug-03	01-Aug-33	30	6.875%	$50,000,000	$521,342	$1,946,809		$47,531,849	7.282%	95.064%	$50,000,000	$47,531,849	4.468%	0.325%
9.31% Series	12-Aug-91	11-Aug-21	30	9.310%	$20,000,000	$176,577	$0		$19,823,423	9.399%	99.117%	$20,000,000	$19,823,423	1.787%	0.168%
6.31% Series	26-May-06	26-May-36	30	6.310%	$175,000,000	$1,125,000	$7,740,000	*20*	$166,135,000	6.704%	94.934%	$175,000,000	$166,135,000	15.638%	1.048%
6.26% Series	26-May-06	26-May-31	25	6.260%	$100,000,000	$750,000	$5,160,000	*20*	$94,090,000	6.753%	94.090%	$100,000,000	$94,090,000	8.936%	0.603%
6.15% Series	01-Apr-07	01-Apr-37	30	6.150%	$112,500,000	$1,500,000	$0	*19*	$111,000,000	6.224%	98.667%	$112,500,000	$111,000,000	10.053%	0.626%
5.77% Series	01-Aug-07	01-Aug-17	10	5.770%	$62,500,000	$1,500,000	$0	*21*	$61,000,000	5.904%	97.600%	$62,500,000	$61,000,000	5.585%	0.330%
7.875% Series	13-Mar-00	15-Mar-10	10	7.875%	$149,250,000	$1,472,800	$1,266,000	*17*	$146,511,200	8.128%	98.165%	$149,250,000	$146,511,200	13.337%	1.084%
Brdmn 98A Fixed	28-May-98	01-May-33	35	5.200%	$23,600,000	$85,850	$1,267,030	*5,16,18*	$22,247,120	5.544%	94.267%	$23,600,000	$22,247,120	2.109%	0.117%
Clstrp 98A Fixed	28-May-98	30-Apr-33	35	5.200%	$97,800,000	$355,835	$1,617,373	*6,16,18*	$95,826,792	5.336%	97.982%	$97,800,000	$95,826,792	8.740%	0.466%
Colstrip 98B Fixed	28-May-98	30-Apr-33	35	5.450%	$21,000,000	$76,420	$438,143	*16,18*	$20,485,437	5.620%	97.550%	$21,000,000	$20,485,437	1.877%	0.105%
Trojan 85A Fixed	01-Jul-98	01-Apr-10	25	4.800%	$20,200,000	$218,352	$244,162	*16*	$19,737,486	5.058%	97.710%	$20,200,000	$19,737,486	1.805%	0.091%
Trojan 85B Fixed	01-Jul-98	01-Jun-10	25	4.800%	$16,700,000	$180,519	$184,473	*16*	$16,335,008	5.046%	97.814%	$16,700,000	$16,335,008	1.492%	0.075%
Trojan 90A Fixed	01-Jul-98	01-Aug-14	16	5.250%	$9,600,000	$103,771	$184,980	*16*	$9,311,249	5.537%	96.992%	$9,600,000	$9,311,249	0.858%	0.048%
Troj Ser 1990B-Fixed	15-Dec-90	15-Dec-14	24	7.125%	$5,100,000	$163,234	$0		$4,936,766	7.412%	96.799%	$5,100,000	$4,936,766	0.456%	0.034%
Coyote 96 Float	01-Dec-96	01-Dec-31	35	Variable	$5,800,000	$159,350	$0		$5,640,650	3.671%	97.253%	$5,800,000	$5,640,650	0.518%	0.019%
Loss on Reacquired Debt							$374,581		($374,581)						
Total Debt					$1,119,050,000	$25,745,977	$24,317,169		$1,068,986,854			$1,119,050,000	$1,069,361,435	100.00%	6.693%
Cost of LT Debt (includes loss from reacquired)															**6.727%**

Losses on Reacquired Debt	Reacquired	Gross Proceeds	Total Gain/Loss to Amortize	Annual Expense
13.50% FMB Due 10/1/12	25-Apr-88	$75,000,000	$8,989,952	$374,581
				$374,581

FOOTNOTES

5 PCB Series Due 4/1/84-11 - PGE refunded its $25.45m Fixed Rate Port of Morrow PCB scheduled to expire serially from 1984-2011 with 26 year variable rate PCB due 6/1/13. Unamortized debt expense and call premium totaled $1,395,954, which is being recovered over the life of the replacement PCB.

16 On 5/28/98, PGE re-marketed and extended the Boardman 88A (now Boardman 98A), the Colstrip 83A-D, the Colstrip 84 (these issues combined to form Colstrip 98A), and the Colstrip 86 (now colstrip 98B). The previous issue costs and premiums were amortized to 5/28/98 and included in the call premium column. The remarketing costs are included in the Issue Costs column. All of the above issues' coupon costs were fixed. On 7/1/98, the Trojan variable rates were fixed, although not extended.

17 One time buydown event of $750,000 in July 2002.

18 Ledger # changed between 2000&2001 when interest rate swaped from floating to fixed.

19 First placement ($150M) of $300M planned issuance in April 2007. The amount and weighted value is based on the average monthly balance over the 2007 calendar year.

Year End 2006	**Jan-07**	**Feb-07**	**Mar-07**	**Apr-07**	**May-07**	**Jun-07**	**Jul-07**	**Aug-07**	**Sep-07**	**Oct-07**	**Nov-07**	**Dec-07**	Average of Averages
$0	$0	$0	$0	$150,000,000	$150,000,000	$150,000,000	$150,000,000	$150,000,000	$150,000,000	$150,000,000	$150,000,000	$150,000,000	
Average Monthly Balance	$0	$0	$0	$150,000,000	$150,000,000	$150,000,000	$150,000,000	$150,000,000	$150,000,000	$150,000,000	$150,000,000	$150,000,000	$112,500,000

20 There was a $12.9 million call premium on the 8.125% redeemed issue. This premium is rolled into the new debt and will be paid over the period of the May 2006 issuances.

21 Second placement ($150M) of $300M planned issuance in August 2007. The amount and weighted value is based on the average monthly balance over the 2007 calendar year.

Year End 2006	**Jan-07**	**Feb-07**	**Mar-07**	**Apr-07**	**May-07**	**Jun-07**	**Jul-07**	**Aug-07**	**Sep-07**	**Oct-07**	**Nov-07**	**Dec-07**	Average of Averages
$0	$0	$0	$0	$0	$0	$0	$0	$150,000,000	$150,000,000	$150,000,000	$150,000,000	$150,000,000	
Average Monthly Balance	$0	$0	$0	$0	$0	$0	$0	$150,000,000	$150,000,000	$150,000,000	$150,000,000	$150,000,000	$62,500,000

Portland General Electric

Composite Cost of Capital

Test Year Based on 12 Months Ending 12/31/07

	Average Outstanding *	Percent	Percent Cost	Weighted Average Cost
Long Term Debt	$1,119,050	46.73%	6.73%	3.14%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$1,275,487	53.27%	10.75%	5.73%
Composite Cost of Capital	$2,394,537	100.00%		8.87%

* Represents the Average of the Month End Balances

Data Request:

90. Staff states that PGE began to accumulate excess capital after Enron filed for bankruptcy and investing it in "short-term" investments (Staff Exhibit 1400, page 4, lines 3-4).
    a. Please define "excess capital" as used by Staff in this passage.
    b. Please provide the documentation on which Staff relied that demonstrates that PGE had or accumulated "excess capital" after Enron filed for bankruptcy.
    c. Please specify the amount or percentage of PGE's capital that was "excess capital" by year from 2001 through 2006 and explain why this amount or percentage is "excess."
    d. Please provide the documentation that PGE invested this "excess capital" in "short-term investments."
    e. Please specify by year and by type the "short-term investments" in which PGE has maintained its "excess capital" from 2001 through 2005.
    f. Please define the "short-term investments" as used by Staff in this passage.

Staff Response:

a. Staff does not assign a specific meaning to this term, but it should be construed in its normal accounting sense, which, for example, includes short-term corporate cash that could have provided the support for a dividend payment to balance PGE's capital structure. Additionally, the term is meant to include the net income generated by PGE's operations that were not being sent to Enron as dividends. This would have been reflected as a growing equity base on the Company's balance sheet. Please refer to part (b) for references to PGE's internal planning documents from where the meaning can be further understood.
b. Please see the confidential exhibits relating to PGE's 2005 and 2006-2007 Finance and Investment Plan. For example, see the top of Staff/1403 Morgan/5 for a specific reference relating to PGE's freezing of dividend payments since 2001. See also Staff/1403 Morgan/23 relating to planned versus actual events.
c. Staff does not have the specific figures calculated, but directs the Company to the figures it provided to Staff, also available in Staff/1403.
d. See Staff/1403 Morgan/4-5 and Morgan/21-22, as examples.
e. Staff has not completed the requested analysis.
f. The term "short term investments" is that which the Company has defined as such in its balance sheets as indicated in Staff/1403, as identified above.

Analyst Earnings Growth Expectations from 'Morgan 1401.xls'

Staff Exhibit 1402 does not match EPS growth estimates from Kiplingers, FirstCall, Zack's, Reuters, or Value Line
Staff averages are consistently less than the validated averages.
Kiplingers and Zacks provide identical estimates and should not be considered two separate sources

Electric Companies		Kiplingers	Firstcall	Zack's	Reuters	Value Line
		Next 5 years	Next 5 years	Next 5 years	Next 5 years	Next 5 years
	Ticker					
Alliant Energy	LNT	3.00%	2.30%	4.00%	3.67%	4.50%
Amer. Elec. Power	AEP	3.00%	3.00%	3.20%	3.50%	5.00%
Consol. Edison	ED	3.00%	4.00%	3.50%	3.44%	1.50%
Energy East Corp.	EAS	4.00%	4.00%	4.50%	4.33%	4.50%
IDACORP, Inc.	IDA	5.00%	5.00%	4.00%	4.75%	4.50%
MGE Energy	MGEE	N/A	N/A	N/A	N/A	6.00%
NSTAR	NST	5.00%	5.00%	5.80%	5.50%	2.50%
OGE Energy	OGE	3.00%	3.00%	5.00%	4.00%	4.00%
Progress Energy	PGN	4.00%	3.50%	3.60%	3.93%	N/A
Southern Co.	SO	5.00%	5.00%	4.70%	4.50%	4.00%
Wisconsin Energy	WEC	8.00%	8.00%	7.00%	7.27%	6.50%
Xcel Energy Inc.	XEL	4.00%	4.50%	4.30%	4.17%	7.50%
STAFF AVERAGE		**4.27%**	**4.30%**	**4.51%**	**4.46%**	**4.59%**

*** Incorrect Values are Shaded*

Verified Analyst Earnings Growth Expectations

Sources:

Kiplingers: http://kiplinger.stockgroup.com/sn_earningsestimates.asp?symbol=XXX where XXX is ticker.
FirstCall: Thomson consensus growth rate. All estimates are median estimates.
Zack's: http://www.zacks.com/research/report.php?type=estimates&t=XXX where XXX is ticker.
Reuter's: http://stocks.us.reuters.com/stocks/estimates.asp?symbol=XXX where XXX is ticker.
Value Line: UE 180 Staff/Morgan 1402

Electric Companies		**Kiplingers**	**FirstCall**	**Zack's**	**Reuters**	**Value Line**
		Next 5 years	Next 5 years	Next 5 years	Next 5 years	Next 5 years
	Ticker					
Alliant Energy	LNT	4.00%	6.00%	4.00%	4.33%	4.50%
Amer. Elec. Power	AEP	3.86%	4.00%	3.86%	4.26%	5.00%
Consol. Edison	ED	3.71%	3.00%	3.71%	3.73%	3.00%
Energy East Corp.	EAS	4.50%	4.50%	4.50%	4.33%	4.00%
IDACORP, Inc.	IDA	4.67%	5.00%	4.67%	4.67%	4.50%
MGE Energy	MGEE	N/A	N/A	N/A	N/A	6.00%
NSTAR	NST	5.50%	5.00%	5.50%	5.40%	6.00%
OGE Energy	OGE	5.00%	3.00%	5.00%	N/A	4.00%
Progress Energy	PGN	3.64%	3.25%	3.64%	3.83%	NA (1.5%)
Southern Co.	SO	4.67%	5.00%	4.67%	4.70%	3.50%
Wisconsin Energy	WEC	7.40%	8.00%	7.40%	6.95%	6.50%
Xcel Energy Inc.	XEL	4.33%	4.00%	4.33%	4.17%	6.00%
AVERAGE		**4.66%**	**4.61%**	**4.66%**	**4.64%**	**4.82%**
Staff Averages (Morgan 1401.xls)						
AVERAGE		**4.27%**	**4.30%**	**4.51%**	**4.46%**	**4.59%**
Difference		Kiplingers	FirstCall	Zack's	Reuters	Value Line
AVERAGE		**-0.39%**	**-0.31%**	**-0.15%**	**-0.18%**	**-0.23%**

UE 180 - UE 181 - UE 184 / PGE Exhibit 2704
Hager - Valach / 2

Moody's Investors Service

Global Credit Research
Credit Opinion
12 OCT 2006

Credit Opinion: Portland General Electric Company

Portland General Electric Company

Portland, Oregon, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa2
Bkd First Mortgage Bonds	Aaa
Senior Secured	Baa1
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Preferred Stock	Ba1
Commercial Paper	P-2

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Key Indicators

Portland General Electric Company

	LTM 2Q 06	2005	2004	2003
(CFO Pre-W/C + Interest) / Interest Expense [1]	3.6x	5.0x	6.2x	4.5x
(CFO Pre-W/C) / Debt [1]	16.0%	28.5%	35.7%	26.5%
(CFO Pre-W/C - Dividends) / Debt [1]	2.5%	13.5%	35.7%	26.5%
Debt / Book Capitalization	45.5%	43.2%	39.7%	41.6%
ROE (NPATBUI / Avg. Equity) [2]	1.9%	4.7%	6.7%	4.0%
Dividends as a % of NPATBUI [2]	653.4%	266.6%	0.0%	0.0%

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [2] NPATBUI is Net Profit After-tax Befor Unusual Items

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Company Profile

Portland General Electric Company (PGE) is a vertically integrated electric utility company, with headquarters in Portland, Oregon, providing regulated service to about 791,000 retail accounts throughout a service territory spanning roughly 4,000 square miles. The service territory includes 52 cities (Portland and Salem being the two largest), and has a population of about 1.5 million or 43% of Oregon's population. PGE's common stock is now listed and traded on the New York Stock Exchange since it is no longer a wholly-owned subsidiary of Enron Corp. following cancellation of PGE's old stock and issuance of 62,500,000 shares of new stock. This step preceded the initial distribution of approximately 43% of the new shares to Enron creditors holding allowed settled claims as of April 3, 2006. The remainder of PGE's stock was placed in a disputed claims reserve (DCR) trust. Since the initial distribution, additional shares have been distributed to other Enron creditors as the bankruptcy court settled disputed claims. As of June 30, 2006, the DCR trust held 55% of PGE's total issued and outstanding common stock and the DCR trust will continue to distribute additional shares as the bankruptcy court settles additional disputed claims in the future.

PGE's net plant in service approximates $2.1 billion, about 85% of which is comprised of electric generation, transmission and distribution infrastructure. During 2005, PGE retail load was serviced by hydro power sources (21%), coal-fired sources (22%), gas/oil-fired sources (8%), and purchased power (49%). The degree of dependence on purchased power is expected to decline in future years as PGE completes construction of additional gas-fired and wind generating capacity.

The economy in PGE's service territory has supported annualized customer growth of close to 2% over the past ten years and modest annualized load growth of about 1% during the same time period. About 85% of PGE's revenues are derived from the sale of electricity to the more stable and predictable residential and commercial customers. The company's industrial sales, which can be subject to more variability, are spread among the technology, paper, retail, manufacturing, and services sectors. About 60% of PGE's 2005 industrial sales were made to the technology and paper sectors combined. Importantly, there is not undue concern about customer concentration, with no single customer accounting for more than 4% of retail revenues. PGE's larger industrial customers include Boeing, Boise Cascade, Intel, and Nike.

PGE's retail rates are subject to the regulatory jurisdiction of the Oregon Public Utility Commission (OPUC).

Rating Rationale

PGE's ratings take into account several key factors, including its business and regulatory risk profile, its financial metrics, its resource strategy and supply risk, and its liquidity. We currently view PGE's business and regulatory risk profile as consistent with the A rating category. The company's recent financial metrics, including the utility's coverage of interest and debt by cash flow from operations (exclusive of working capital changes) and its adjusted debt to adjusted capitalization, are consistent with the Baa rating category. PGE's resource strategy and its liquidity profile are also in line with the Baa rating category. Collectively, our assessment of these key factors is consistent with the Baa2 rating assigned to PGE's senior unsecured debt.

Business and Regulatory Risk Profile

Our assessment of PGE's business and regulatory risk profile takes into account the vertically integrated nature of the utility's operations, the company's proactive and collaborative approach to dealings with the staff and commissioners serving on the OPUC, and the complete separation in April 2006 from Enron Corp., which had been PGE's parent company dating from 1997. With regard to the latter point, although PGE remained insulated from Enron's bankruptcy proceedings, there were lingering concerns about PGE's future ownership until the OPUC denied Texas Pacific Group's request for approval to acquire PGE in a highly leveraged transaction, ultimately leading to the process of issuing stock to creditors which began in April 2006 as described above.

Regulatory Limitation on Common Dividends Continues For Now:

Upon gaining independence from Enron, PGE remains bound by certain regulatory limits on dividends to shareholders by virtue of continuing requirements to maintain a minimum 48% common equity ratio (plus $40 million pending the outcome of the current rate case in Oregon, which is described below). We have historically viewed the OPUC's proactive interest in maintaining PGE's credit quality through a regulatory limitation on dividends as beneficial to PGE's fixed income investors. We note, however, that this regulatory requirement will phase out gradually as the 48% minimum required equity is reduced to 45% when the DCR trust holds between 20% - 40% of PGE's issued and outstanding common stock. Ultimately, the regulatory requirement to maintain a minimum level of common equity in the capital structure goes away entirely once the DCR trust holds less than 20% of PGE's issued and outstanding common stock. We are not unduly concerned about this regulatory change given management's prudent financing strategies demonstrated throughout its ownership by Enron and the utility's stated objective to maintain a roughly 50/50 debt to equity mix in its capital structure going forward. Any unexpected shift towards a more aggressive financing strategy could create downward pressure on PGE's ratings.

General Rate Case Seeks Better Alignment of Costs And Customer Rates:

PGE is in the latter stages of a regulatory proceeding filed with the OPUC in March 2006, in which the utility is seeking approval to increase its general rates by roughly $143 million (8.9%), premised on an allowed return on equity of 10.75%. About half of the requested rate increase is driven by power and fuel costs incorporating PGE's annual power cost filing under the Resource Valuation Mechanism (RVM) as part of the general rate case. To date, the RVM has proven to be a reasonably effective means for PGE to update its variable power costs annually for inclusion in base rates for the following year. Under guidelines established in Oregon's energy industry restructuring law, the RVM uses both market prices and values associated with the utility's resources in establishing power costs and setting prices.

The remainder of the requested rate increase relates to PGE's attempt to recover its investment in the Port Westward natural gas-fired generation plant (see below for more details) and other non-power-related costs of service. Settlement discussions have led to resolution of some of the revenue requirement issues in this case. A final decision in this proceeding is expected in early January 2007, but it would appear that the effective date of the portion of any approved rate increases tied to the Port Westward plant will coincide with commencement of commercial operation, which is expected in the first quarter of 2007. Our ratings for PGE's debt assume a reasonably supportive outcome in this proceeding.

Attempts To Implement A Power Cost Adjustment (PCA) Mechanism:

The slow pace of deregulation under Oregon law has effectively been neutral to PGE's credit quality and the OPUC supported recovery of PGE's deferred energy costs incurred during 2001 and 2002 when state regulators approved a temporary PCA mechanism during certain periods. During 2003 and 2004, PGE did not benefit from deferral for subsequent recovery of power supply costs in excess of rates in effect at the time, but the utility was proactive in minimizing the financial impact. In addition, the OPUC denied a stipulation between PGE and the OPUC staff for a hydroelectric PCA mechanism for 2005 and 2006. Whether PGE should have a PCA and the structure of any such PCA is an issue being considered in the context of the currently pending rate case. It is still unclear how receptive the OPUC might be to implementing some type of PCA mechanism. It would be our view that along with the construction of additional gas-fired generation at the Port Westward site, the PCA mechanism would substantially mitigate PGE's exposure to hydroelectric volatility that was evidenced by persistent drought conditions that prevailed in the Northwest during 2000 - 2005.

Resource Strategy And Supply Risk

Higher Than Historical Capital Program For The Next Couple Of Years:

Since PGE elected to permanently shut down its Trojan nuclear power plant in the early 1990's, it has relied extensively on purchased power arrangements to meet its retail customers' power needs. More recently, PGE, like many of its peers in the Northwest, has adopted plans to make itself less dependent on the wholesale power market. As this strategy plays out, PGE faces an increased capital budget, especially over the next two years as it adds to its owned generation (i.e. construction of the 400-megawatt Port Westward gas-fired plant, which is on schedule for completion in the first quarter of 2007) and maintains reliability of its existing infrastructure. At this juncture, PGE is projecting capital spending in the range of $340 to $360 million in 2006, in the range of $210 to $230 million in 2007, and in the range of $290 to $310 million in 2008. However, these amounts are likely to increase by as much as $218 million over 2006-2008, but the specific timing of the spending depends on PGE's efforts to purchase turbines for development of the Biglow Canyon Wind Farm. This part of PGE's resource strategy would allow the utility to develop up to 450 megawatts of energy capacity.

Moody's ratings of PGE's debt take into account the expectation that the utility will need to externally fund a portion of these investments, but should be able to do so while maintaining its currently sound financial profile (including debt not to exceed 50% of total capitalization) and sufficient liquidity. Consistent with this view, we note that PGE issued $275 million of first mortgage bonds on May 24, 2006, $150 million of which was used for early retirement of higher cost debt and the remainder for general corporate purposes (i.e. construction at the Port Westward site).

Boardman Plant Outage:

During the fourth quarter of 2005 and the first half of 2006, PGE experienced increased working capital needs to fund replacement power costs because of the unplanned outage at its Boardman coal plant. PGE is in the midst of regulatory proceedings to determine the extent to which it might be entitled to recovery of certain replacement power costs incurred during the outage. Such proceedings can sometimes take on a contentious tone, particularly from the consumer advocate's perspective. PGE has already dealt with the higher working capital requirements that resulted from the outage and the effects have been reflected in the lower earnings reported during the aforementioned quarterly periods. PGE's future financial metrics could, however, benefit from a supportive ruling by the OPUC as it relates to future rate treatment of these costs.

Other Factors

Satisfactory Resolution Of Various Contingencies Related To Past Ownership:

Some of the more significant contingencies that PGE might have had to deal with because of its prior ownership by Enron included taxes and pension benefits. Various agreements entered into between Enron and PGE, most recently a separation agreement of April 3, 2006, generally provide for resolution of these issues and have been factored into our current ratings for PGE.

Litigation Over PGE's Earned Returns On Past Investments In Its Trojan Nuclear Plant:

In 1995, the OPUC issued an order granting PGE's right to recovery of, and a return on, 87% of its then remaining investment in Trojan nuclear plant costs, as well as full recovery of its estimated decommissioning costs through 2011. At this point, there are no legal questions surrounding PGE's right to full recovery of the decommissioning costs. However, there have been periodic legal challenges and law suits that have been raised at various points in time as relates to the OPUC's 1995 decision. At this time, the issues apparently relate primarily to PGE's right to retain amounts recovered through past rates that provided for return on the 87% remaining investment in Trojan. It is unclear at this point precisely what PGE's financial exposure might be, if any, and PGE has not taken any reserves related to the matter. Nevertheless, as a precaution, PGE has increased the size of its bank credit facility above what it might otherwise have in place. The extra liquidity is intended in part to provide flexibility, if needed, to post collateral in conjunction with pursuing legal rights of appeal in the event of any adverse ruling. Most recently, the Oregon Supreme Court ruled that a class action lawsuit relating to this matter must be placed on hold pending completion of the OPUC's pending review of the rate matter following a remand to the OPUC by the Marion County Circuit Court. Given the current schedules for regulatory proceedings and litigation relating to this matter, it remains unclear precisely when the matter will be resolved. Moody's will continue to monitor this issue, but does not believe it is cause for undue concern at this time.

Oregon Senate Bill 408 (SB 408):

SB 408 seeks to adjust the way in which PGE and most other Oregon-based investor-owned electric and gas utilities collect income taxes from ratepayers. On the heels of passage of this legislation, the OPUC adopted rules in mid-September 2006 to govern the utilities as they implement the law. Going forward, the utilities will be required to file annual tax reports with the OPUC by mid-October with the purpose being to compare taxes actually paid by the utility for a specified period with the authorized amount collected in actual rates charged to customers during that same period. Subject to certain formulas, utilities would be required to provide refunds to customers for over-collected amounts or entitled to assess additional charges to customers for under-collected amounts.

After assessing its own situation relating to SB 408, in early 2006 PGE actually took a non-cash $9 million (pre-tax) reserve in anticipation of the refunds it might be required to provide to its customers. Given the lower earnings generated to date this year, due to the aforementioned Boardman outage and other factors, we would not be surprised to see PGE take additional non-cash reserves as it reports results for the third and fourth quarters of 2006. The precise timing of the cash impact of any required refunds is uncertain at this time, but could be delayed until 2008. In the meantime, we would expect continued scrutiny of SB 408 by legislators, regulators, and the utilities given what appear to be a fairly widespread view that implementation of the bill is causing unintended negative consequences for the utilities. As additional information unfolds, we will assess the degree of credit impact for PGE.

Financial Metrics

In earlier reports, we have said that PGE's financial metrics during the period of Enron's bankruptcy could have supported ratings higher than the levels maintained during that period. However, the ratings were constrained during that period by uncertainty regarding the company's on-going ownership and contingent liabilities. More recently, we note that PGE's key metrics, including its coverage of interest and debt by cash flow from operations (exclusive of working capital changes), have slipped. This trend is the result of lower earnings in the second half of last year and the first quarter of this year, largely attributable to the higher power supply costs incurred due to the prolonged outage at the Boardman coal plant. In addition, PGE experienced increased winter storm restoration costs during the winter of 2006 and higher customer support costs.

For the trailing 12-months ended June 30, 2006, PGE's cash flow from operations (exclusive of working capital changes) covered its interest and debt by 3.6x and 16%, respectively, which is considerably below the three year averages of 5.2x and 30.2%, respectively, for the 12/31/2003-12/31/2005 periods. Nevertheless, these coverage metrics for the most recent 12-month period still leave PGE within a range appropriate for a regulated electric utility company conducting business in a supportive regulatory environment, as outlined in Moody's Global Rating Methodology for Regulated Electric Utilities. If PGE can obtain a supportive outcome in the pending rate case, maintain normal operations at the Boardman plant, become less reliant on higher cost purchased power in the future, and adequately cope with the financial impacts of SB 408, then we believe that PGE can reverse this trend in 2007 and beyond to produce coverage of interest and debt above 4x and in the low-to-mid-20% range, respectively, all other factors equal.

Meanwhile, we note that PGE has maintained a fairly thick equity cushion over the years when compared to its peers. As noted above, there is a possibility for a modest increase in the debt level as PGE finances a higher than historical level of capital expenditures over the next two to three years, but this should not exceed 50% of total capitalization based on management's public assertions.

Liquidity

Against the backdrop of PGE's various capital needs, we believe the company will maintain sufficient liquidity over the next 12 months. This view reflects our expectations that PGE's cash flow from operations (exclusive of working capital changes) will be near $200 million in 2006 and that PGE can also supplement its internally generated cash flow through issuance of commercial paper or direct borrowings under its $400 million committed five-year senior unsecured bank credit facility to meet short-term cash needs. In February, the Federal Energy Regulatory Commission authorized that PGE could issue short-term debt up to a maximum $400 million outstanding at any given time during the two-year period February 8, 2006 through February 7, 2008. We do not expect PGE to come anywhere near the maximum allowed level, with peak short-term debt balances not likely to exceed $50 million over the next 12 months.

Meanwhile, PGE has very modest debt maturities over the next several years, has recently been maintaining more modest cash balances compared to in excess of $300 million at times when it was owned by Enron, had no commercial paper outstanding at June 30, 2006, and we do not expect near-term drawdowns under the company's $400 million of bank credit facilities to meet liquidity needs. PGE's existing 5-year bank facility was recently extended to July 14, 2011 with improved terms and conditions. The facility contains a covenant limiting the maximum debt level to 65% and does not contain a material adverse change provision. The regulatory mandate to maintain a minimum common equity ratio of 48% is even more restrictive, and is ultimately what currently guides PGE in determining the mix of securities in its capital structure. PGE's indebtedness to total capitalization, as calculated under the facility was 44.9% at June 30, 2006, leaving ample cushion under the covenant. Importantly, PGE's bank credit facility does not contain rating triggers that would cause acceleration, default, or puts, although it does contain rating sensitive pricing.

Rating Outlook

The stable rating outlook assumes that PGE will continue to maintain its current financial profile, at a minimum, while being guided by prudent financing strategies for its large capital program and helped by supportive regulation in Oregon.

What Could Change the Rating - Up

A constructive outcome in PGE's pending rate case, which results in a reasonable opportunity for the utility to receive substantial and timely recovery of costs and to earn a return on the significant planned additions to rate base would be beneficial to PGE's credit quality and could contribute to an upgrade over the intermediate term. For example, an upgrade could occur if PGE demonstrates an ability to produce key financial metrics similar to those achieved during the 2002 - 2005 period on a sustainable basis. Also, satisfactory resolution of the various contingencies related to Trojan plant-related litigation, Senate Bill 408, and higher wholesale power costs incurred during the prolonged outage at the Boardman coal-fired plant during November 2005 through February 2006 would also be favorable credit developments.

What Could Change the Rating - Down

Any unexpectedly harsh decision by the OPUC in the currently pending and/or future rate proceedings that cause PGE to fall short of current financial expectations could result in a negative outlook or rating downgrade. This could include a weakening of the ratio of sustainable cash flow from operations (exclusive of working capital changes) to adjusted debt below 20%.

Rating Factors

Portland General Electric Company

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	Medium	Low	Medium	Low	Medium	Low	Medium	Low
CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

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MOODY'S hereby discloses that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by MOODY'S have, prior to assignment of any rating, agreed to pay to MOODY'S for appraisal and rating services rendered by it fees ranging from $1,500 to $2,400,000. Moody's Corporation (MCO) and its wholly-owned credit rating agency subsidiary, Moody's Investors Service (MIS), also maintain policies and procedures to address the independence of MIS's ratings and rating processes. Information regarding certain affiliations that may exist between directors of MCO and rated entities, and between entities who hold ratings from MIS and have also publicly reported to the SEC an ownership interest in MCO of more than 5%, is posted annually on Moody's website at www.moodys.com under the heading "Shareholder Relations - Corporate Governance - Director and Shareholder Affiliation Policy."

This credit rating opinion has been prepared without taking into account any of your objectives, financial situation or needs. You should, before acting on the opinion, consider the appropriateness of the opinion having regard to your own objectives, financial situation and needs.

RESEARCH

Summary:

Portland General Electric Co.

Publication date: 25-Sep-2006
Primary Credit Analyst: Leo Carrillo, San Francisco (1) 415-371-5077; mailto:leo_carrillo@standardandpoors.com

Credit Rating: BBB+/Negative/A-2

Rationale

The ratings on Portland General Electric (PGE) reflect the company's satisfactory business profile and strong financial profile. PGE's business profile is '5' on a 10-point scale, where '1' is excellent.

PGE is an integrated electric utility serving about 791,000 customers in Northwest Oregon, including the cities of Portland and Salem. PGE is no longer a subsidiary of its former parent, Enron Corp., having distributed 55% of its newly issued common stock as of April 3, 2006. New PGE common stock was issued to Enron creditors holding allowed claims (43%) and to a disputed claims reserve (57%). As envisioned under the Enron reorganization plan, the remaining shares in the disputed claims reserve will be distributed over time as such creditors' claims are settled, a process that could take years.

As of June 30, 2006, PGE had about $1 billion in total debt.

Supportive regulation by the Oregon Public Utility Commission (OPUC) has historically been a key credit strength, although recent recommendations by the commission staff suggest that the regulatory environment may become less favorable for the company. In addition, the commission's requirement for a 48% equity layer at PGE will gradually fall away after the distribution of newly issued common stock to Enron's creditors, as part of PGE's plan to eliminate over time the structural ring-fencing that insulated the company's credit quality from Enron for the past four years.

The commission is presently reviewing PGE's 2007 general rate case (GRC), which it filed in March 2006. In its filing, PGE requested that the OPUC continue to use a mechanism very similar to the "resource valuation mechanism" (RVM) currently in place, but in addition, the company proposed a comprehensive power cost adjustment (PCA) mechanism to better address all power cost variability issues, including hydro variation. OPUC staff recommended that the company's requested $143 million increase in revenue requirement be reduced by $65 million to $75 million, in addition to the $20 million in operating and maintenance cost reductions already stipulated by the parties. The rate case is not expected to be resolved until January 2007.

The RVM mechanism is a critically important facet of PGE's rate design that allows the company to adjust its rates at the beginning of each year based on the company's forecast of net variable power costs as of November of the previous year, by which time PGE has typically contracted for 90%-95% of its energy needs. Although the company's RVM mechanism allows PGE to pass through to retail customers most of the company's projected power cost variation in November of each year, there is currently no mechanism to share the risks and rewards of hydro variability or other costs that could cause actual power costs to deviate from forecasted levels during the subsequent months.

PGE has 1,973 MW of efficient, low-cost hydro, coal, and gas-fired generation resources. PGE's most economical resources are its low-cost hydroelectric power purchases from the Columbia River power system and Bonneville Power Administration, which together account for 20% to 25% of energy requirements. The company has one large coal resource, a 380 MW stake in the 585-MW Boardman coal plant, but since October 2005, the plant has experienced three forced outages at its largest owned baseload plant, and over the long term it faces potentially high capital requirements to meet increasingly stringent environmental regulations. Plant operations resumed on July 5, 2006.

As a result of the forced outages at Boardman, the company has incurred about $92 million in replacement power costs through July 5, 2006. The company has filed an application with the OPUC seeking deferral of the $46 million in replacement power costs incurred through Feb. 5, 2006, when Boardman returned to service after the first plant outage. PGE's request for Boardman replacement cost recovery from the OPUC is still pending.

PGE is engaged in a program to acquire additional resources to reduce its dependence on short-term power purchases (typically of three years or less) to about 30%-35% of its energy requirements, which subjects the company to heightened market risk. PGE's integrated resource plan (IRP) aims for greater ownership of generating capacity through the 400-MW Port Westward gas-fired combined cycle power plant, currently under construction, which will be included in the rate base in the 2006 general rate case. The Port Westward acquisition will supplement existing owned gas-fired generation that currently accounts for 5% to 10% of power supplies.

PGE faces regulatory and litigation risk with respect to the Trojan nuclear plant, where lawsuits have been filed seeking a refund of $260 million representing a return on its investment in Trojan. On Aug. 31, 2006, the Oregon Supreme Court issued a ruling that the OPUC had primary jurisdiction to determine what remedy, if any, is due to PGE ratepayers, and to suspend the court's class action proceedings, pending a final decision by the OPUC in its own proceedings on the matter. Final resolution of the matter is likely more than a year away. In addition, the Portland City Council's attempt to investigate PGE's tax payment and trading practices could result in the city's attempt to assume rate-setting authority with regard to electric rates for customers within city limits. Although the city's investigation appears to have stalled, it has not been officially closed.

The company's latest financial metrics are adequate, but could weaken going forward due to delayed or incomplete recovery of Boardman replacement power costs, an unfavorable general rate case decision, adverse market or hydro conditions, the Trojan litigation, or the investigation by the City of Portland. Adjusted funds from operations (FFO) coverage of interest was 3.4x for the 12-month period ended June 30, 2006, while adjusted FFO coverage of debt was 18%. Adjusted total debt-to-capitalization increased to about 53% as of June 30, 2006. Standard & Poor's adjusts the company's financial ratios to reflect $241 million of power purchase agreements, as well as the addition of about $575 million in debt to support capital spending over the next three years.

Short-term credit factors

The rating on PGE's short-term debt is 'A-2', which reflects adequate liquidity, modest debt maturities, increased but manageable reliance on external borrowings to fund capital expenditures, and the expectation that the utility will continue to generate stable cash flow.

The RVM in Oregon allows for the annual reset of rates based on PGE's forecast of net variable power costs for that year. By November, when the RVM is set, 90%-95% of PGE's open position is filled for the next year under average water conditions. Thus, the main liquidity risk from power supply costs arises from hydro variations and other factors that were not incorporated into the November forecast. PGE does not currently have a power cost adjustment or a hydro cost deferral mechanism to pass this risk on to customers.

A $400 million, five-year unsecured revolving credit facility provides adequate liquidity for operations. At June 30, 2006, the company had utilized approximately $5 million in LOCs. The facility contains a financial covenant limiting leverage to 65% of total capitalization, with which the company was in compliance as of June 30, 2006.

Debt maturities are manageable at $9 million in 2006 and $50 million in 2007. External funding of about $575 million will be required in 2006-2008 to fund debt maturities and capital expenditures. PGE has long maintained access to the capital markets, event throughout the Enron bankruptcy.

Given its substantial purchased power requirements, PGE has some potential exposure to collateral calls in the event of market price swings or lowered ratings. As of June 30, 2006, PGE had posted approximately $6 million of collateral. A lowering of its rating by a single rating agency to below investment grade would require an additional $52 million in collateral; a lowered rating by two agencies would require $64 million. Under Standard & Poor's liquidity survey, PGE's market and credit event liquidity adequacy ratio is estimated to be above 3.0x.

Outlook

The negative outlook reflects a weakened financial profile, increasing capital needs, an uncertain regulatory environment, and a number of ongoing issues that could negatively affect the company over the next few years. Concerns include uncertain recovery of replacement power costs related to the four-month Boardman plant outage, risks from hydro-related and other power cost variations that cannot currently be passed through to customers, contingent financial exposure related to the Trojan litigation, and Portland's ongoing attempts to investigate PGE's taxes and trading practices.

Weak financial performance could lead to lower ratings, particularly if it is the result of inadequate rate relief, punitive regulatory treatment of Boardman outage costs, or the imposition of an unfavorable power cost recovery mechanism. In contrast, the outlook could eventually be restored to stable if financial and rate relief measures return to adequate levels; a sufficiently supportive PCA mechanism is adopted in addition to the extension of the RVM; and other medium-term risks--such as the Trojan litigation and the City of Portland's investigation--are successfully resolved.

FitchRatings
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Corporate Finance

Global Power/North America
Credit Analysis

Portland General Electric Company

Ratings

Security Class	Current Rating	Previous Rating	Date Changed
IDR	BBB	NR	12/6/05
FMB	A–	BBB–	3/28/05
Secured Notes	A–	BBB–	3/28/05
Unsecured Debt	BBB+	BB	3/28/05

IDR – Issuer default rating. FMB – First-mortgage bond. NR – Not rated.

Rating Watch...None
Rating Outlook...Stable

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Profile

PGE is an integrated electric utility serving approximately 780,000 retail customers in a 4,000 square mile approved service territory in northwest Oregon. The company also sells power and natural gas at wholesale in the western United States. With the issuance of new common stock in early April 2006, PGE is no longer a subsidiary of reorganized Enron.

Related Research

- Press Release April 18, 2006.
- Credit Update, April 13, 2005.

Key Credit Strengths

- Relatively low debt burden and strong credit metrics.
- Focused utility-centric strategy.
- Annual resource valuation mechanism.

Key Credit Concerns

- Boardman outage.
- Adverse political environment in the city of Portland.
- Reliance on wholesale power markets to meet a significant portion of load requirements.
- Potential deterioration in Oregon regulation.

■ Rating Rationale

The ratings and Stable Rating Outlook reflect Portland General Electric Company's (PGE) strong underlying credit metrics and low debt burden relative to the current rating category. The ratings also benefit from PGE's resource valuation mechanism (RVM), which resets its fuel and purchase power costs on an annual basis. The RVM substantially mitigates the negative financial effect of fuel cost volatility associated with the company's primarily natural gas and hydro fuel mix and dependence on purchased power to meet its growing load requirements. However, because the RVM's annual reset assumes normal hydro generation conditions, PGE retains the risks and benefits associated with any deviations from normal water flows. The utility's pending general rate case (GRC) includes a request for a new power cost adjustment mechanism that would more closely track water conditions and pass through to customers the majority of related costs or benefits.

The ratings also assume reasonable outcomes in the Senate Bill (SB) 408 rule-making proceeding and Trojan Nuclear Plant settlement litigation. The recent cancellation of reorganized Enron Corp.'s (Enron) ownership interest in PGE and the issuance of new PGE shares had no effect on the ratings. The distribution of common shares pursuant to the bankruptcy plan, which was already considered in Fitch Ratings' credit assessment, brings to a close the utility's status as a subsidiary of Enron. Fitch notes that 57% of new PGE shares remain in the disputed claims reserve (DCR) until pending claims in its bankruptcy proceeding are resolved.

The primary concern for investors, in Fitch's view, is the ongoing extended outage at the Boardman plant (see Recent Developments section for further details). The unit has been out of service since October 2005 due to failure of turbine and generator rotors. Repair work is underway, and the plant is expected to return to service in May 2006. Additional concerns include the contentious political environment in the city of Portland, which is attempting to investigate PGE's revenue collected within the city's limits, electric rates that are high relative to regional averages, and significant expected capital expenditures in 2006–2008.

■ Recent Developments

Enron Bankruptcy Plan Update

On April 3, 2006, under the U.S. Bankruptcy Court-approved plan, Enron's ownership interest in PGE was cancelled, and PGE issued 62.5 million new shares of common stock. Approximately 27 million of the new PGE shares were issued to Enron creditors and 35.5 million shares to a DCR. The DCR was established under the bankruptcy plan to hold shares for distribution to creditors. Such distributions are expected to be made semiannually each April and October. The percentage of PGE shares held in the DCR is expected to decline to under 50% by April 2007.

Boardman Plant Outage

The 585-megawatt (mw) Boardman coal-fired generating facility, which is 65% owned by PGE, has been out of service since October 2005 due to failure of turbine and generator rotors. The generator has been removed for repairs, and the plant is expected to return to service by the end of May 2006. Replacement power costs incurred by PGE during the outage totaled $41 million in the fourth quarter of 2005 and are estimated to approximate $45 million in the first quarter of 2006. PGE filed to recover $45 million of replacement power costs associated with the Boardman plant. An Oregon Public Utility Commission (OPUC) order is expected in the near future.

■ Liquidity and Debt Structure

At Dec. 31, 2005, PGE's liquidity position was strong, with no short-term debt outstanding and cash and equivalents of $122 million. The company renegotiated its $50 million 364-day and $100 million three-year revolving credit facilities in 2005, replacing them with a $400 million five-year unsecured revolver, which matures in May 2010.

Scheduled maturities are manageable, with $11 million and $67 million maturing in 2006 and 2007, respectively. No long-term debt is scheduled to mature in 2008 or 2009. Proceeds from the pending $275 million issuance of PGE first-mortgage bonds will be used to redeem $150 million of a total of $335 million of long-term debt scheduled to mature in 2010. The remainder of the funds after fees and the call premium will be used for general corporate purposes and to fund PGE's capital program.

PGE's debt-to-total capitalization ratio was 43% at Dec. 31, 2005, and the ratio of debt-to-funds from operations (FFO) was 3.2 times (x) for the 12 months ended Dec. 31, 2005.

■ Political/Regulatory Update

The city of Portland is attempting to investigate PGE's revenue collected within its limits, which represents approximately 25% of the utility's total revenue. PGE opposes the city's investigation and disputes the city's claim that it can regulate the utility's rates. The matter is likely to be settled in court and could linger for an extended period. Creation of another level of regulatory oversight would be a negative event for PGE's fixed-income investors, especially given the adversarial relationship between the city and the company.

OPUC Overview

The OPUC has generally been constructive, and Fitch's rating assumes future commission rulings will continue to be constructive. However, enactment of tax legislation in Oregon in September 2005 (SB 408) and the commission's September 2005 order in PacifiCorp's (PPW, senior unsecured debt rated 'BBB+' by Fitch) GRC were negative events, in Fitch's view, that could signal a deteriorating political/regulatory environment in the state and is a concern for PGE investors.

The OPUC, in its PPW GRC order incorporated SB 408 and reduced the rate increase proposed under a settlement agreement by approximately $26 million. The order also incorporated a 10% authorized return on equity (ROE), which is below the industry average of approximately 10.75%. The OPUC subsequently accepted PPW's petition for reconsideration of the SB 408 ruling, and a final order is pending.

Fitch expects the rehearing of SB 408 issues in the commission's PPW GRC order, its SB 408 rulemaking and anticipated orders in GRC filings by PGE and PPW to provide clues to the condition of the regulatory climate in Oregon. Significant deterioration in the political/regulatory environment in the state could lead to adverse rating actions.

GRC

On March 13, 2006, PGE filed a GRC seeking a $140 million (8.9%) rate increase. PGE's rate request is based on a 2007 test year and incorporates a 10.75% ROE and a 56% common equity ratio. A final order is expected by year-end 2006. The filing, among other things, seeks recovery of PGE's estimated $275 million–$295 million investment in the 400-mw Port Westward natural gas-fired generating facility. Construction of the plant began February 2005, and the plant is expected to be completed in March 2007. Under PGE's filing, the rate increase would be implemented in two steps with the non-Port Westward rate adjustment taking effect in January 2006 and the Port Westward rate adjustment concomitant with the plant's commercial operation.

The GRC filing includes a request for implementation of an annual variance tariff designed to share with customers the costs or benefits associated with the difference between each year's forecast and actual net variable power costs. The current RVM rate adjustment is set in advance of each year and assumes normal hydro generation conditions in setting net power supply costs for recovery in rates. Therefore, changes in net power supply costs due to better or worse than normal water conditions, as well as other changes in net variable power costs, are absorbed by shareholders. The proposed PGE mechanism would include a deferral and an annual cost recovery true-up process that would pass the majority of such costs or benefits through to customers.

SB 408

Enacted in September 2005, SB 408 requires the OPUC to adjust rates to reflect taxes actually paid to a government agency. The legislation requires that actual taxes paid be compared to amounts reflected in rates. If taxes collected by a utility are greater than amounts actually paid by its corporate parent, due to tax reductions from nonjurisdictional affiliates, the difference would be refunded to rate payers. The commission opened a rule-making process that is expected to be completed in the second half of 2006. The legislation is effective for tax years beginning Jan. 1, 2006.

An adverse outcome could signal a significant deterioration in the Oregon regulatory environment to investors. PGE's maximum exposure in a reasonable worst-case scenario is approximately $35 million (after-tax).

■ Trojan Litigation

In 1995, the OPUC issued an order approving recovery of and on a portion (87%) of PGE's remaining investment in the Trojan nuclear facility and decommissioning costs through 2011. The commission decision was in response to a GRC that was filed in 1993 following the closure of the nuclear facility as part of the company's least cost planning process. In 1998, the Oregon Court of Appeals ruled that the OPUC acted properly in allowing recovery of the Trojan investment but did not have the authority to authorize a return on the investment. The matter was remanded to the OPUC, and an order is expected to be issued shortly. While the company supports no change in rates, the OPUC staff is recommending an approximate $5 million refund.

Separately, two class action suits seeking damages of $260 million were granted class certification by the Marion County Circuit Court. In January 2003, PGE filed a writ of mandamus in 2005 with the Oregon Supreme Court, seeking to dismiss the complaints. The Oregon Supreme Court granted PGE's motion for a writ of mandamus, which if successful could overrule the circuit court decision granting the class action status. Briefs have been filed and a ruling is expected later this year. Regardless of the outcome, further appeals are expected, and Fitch believes it will take at a minimum 18–24 months before the issue is resolved. While the ratings assume reasonable resolution of Trojan matters, an adverse outcome could lead to ratings downgrades.

■ Capital Expenditures, Dividends and Cash Flow

PGE's capital investment increased 31% to $255 million in 2005 from $194 million a year earlier and is expected to increase 24% to $315 million in 2006. Over the 2006–2008 period, forecasted capital expenditures average $280 million per year compared with $205 million annually in 2003–2005. The increase in capital spending reflects, among other things, investments for Port Westward and in fish passage equipment at PGE's hydro generation facilities. Fitch expects PGE to fund approximately 90% of its projected capital expenditures from internal cash flow with the remainder to be funded from external sources. Given the expected level of external funding, PGE's credit metrics are expected to remain strong relative to the rating category, with debt-to-FFO at 4.0x or better in 2006–2008 and FFO-to-interest ranging between 4.7x–4.8x.

Rating Outlook Rationale

The Stable Rating Outlook reflects PGE's strong financial ratios, low debt burden, relatively predictable cash flows and a generally supportive regulatory environment. The Stable Rating Outlook also assumes a return to service of the Boardman facility later this month, no materially adverse results from resolution of the Trojan litigation and SB 408, and no harm from the contentious political environment in the city of Portland. Conversely, the favorable resolution of these overhang issues could, over time, lead to positive rating actions.

What Could Lead to Positive Rating Action?

- Favorable resolution of the overhang from SB 408 and the operating, political/regulatory and litigation issues previously identified.

What Could Lead to Negative Rating Action?

- Continuation of operating problems at the Boardman facility.
- Negative outcomes with respect to Portland politics or an unexpectedly large judgment in the Trojan litigation.
- A negative decision in PGE's pending GRC and/or the SB408 rule-making.

UE 180
PGE's Response to OPUC Data Request No. 579
Attachment 579-B

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Corporate Finance

Financial Summary — Portland General Electric Company

($ Mil., Fiscal Years Ended Dec, 31, 2005)

	2005	2004	2003	2002	2001
Fundamental Ratios (x)					
Funds from Operations/Interest Expense	4.9	6.1	4.5	4.1	4.0
Cash from Operations/Interest Expense	6.2	5.7	4.8	5.1	0.1
Debt/Funds from Operations	3.2	2.5	3.5	4.4	5.0
Operating EBIT/Interest Expense	2.4	2.9	2.1	2.7	2.3
Operating EBITDA/Interest Expense	5.6	6.1	4.7	4.9	4.6
Debt/Operating EBITDA	2.2	2.1	2.5	2.8	3.3
Common Dividend Payout (%)	234.4	0.0	1.7	3.1	131.3
Internal Cash/Capital Expenditures (%)	87.1	175.3	183.2	183.6	(53.7)
Capital Expenditures/Depreciation (%)	109.4	83.3	78.4	102.5	119.4
Profitability					
Revenues	1,446	1,454	1,752	1,855	2,420
Net Revenues	775	787	724	698	686
O&M Expense	296	275	265	265	279
Operating EBITDA	405	440	387	364	342
Depreciation and Amortization Expense	233	233	213	161	170
Operating EBIT	172	207	174	203	172
Interest Expense	72	72	82	74	75
Net Income for Common	64	92	59	64	32
O&M % of Net Revenues	38.2	34.9	36.6	38.0	40.7
Operating EBIT % of Net Revenues	22.2	26.3	24.0	29.1	25.1
Cash Flow					
Cash Flow from Operations	372	340	307	305	(67)
Change in Working Capital	92	(27)	24	73	(292)
Funds from Operations	280	367	283	232	225
Dividends	(150)	0	(1)	(2)	(42)
Capital Expenditures	(255)	(194)	(167)	(165)	(203)
Free Cash Flow	(33)	146	139	138	(312)
Net Other Investment Cash Flow	(4)	9	(9)	19	10
Net Change in Debt	(32)	(61)	(60)	(98)	250
Net Change in Equity	0	0	(3)	(2)	0
Capital Structure					
Short-Term Debt	11	30	56	192	348
Long-Term Debt	879	892	927	827	769
Total Debt	890	922	983	1,019	1,117
Preferred and Minority Equity	0	0	0	27	29
Common Equity	1,197	1,279	1,184	1,129	1,090
Total Capital	2,087	2,201	2,167	2,175	2,236
Total Debt/Total Capital (%)	42.6	41.9	45.4	46.9	50.0
Preferred and Minority Equity/Total Capital (%)	0.0	0.0	0.0	1.2	1.3
Common Equity/Total Capital (%)	57.4	58.1	54.6	51.9	48.7

Operating EBIT – Operating income before nonrecurring items. Operating EBITDA – Operating income before nonrecurring items plus depreciation and amortization expense. O&M – Operations and maintenance. Note: Numbers may not add due to rounding and are adjusted for interest and principal payments on transition property securitization certificates. Long-term debt includes trust preferred securities. Source: Financial data obtained from SNL Energy Information System, provided under license by SNL Financial, LC of Charlottesville, Va.

Recent Authorized ROEs

Date Decision	State	Company Name	Authorized ROE	State Auth PCA?
01/06/2005	South Carolina	South Carolina Electric & Gas	10.70%	Y
01/28/2005	Kansas	Aquila Networks-WPK	10.50%	Y
02/18/2005	Washington	Puget Sound Energy	10.30%	Y
02/25/2005	Utah	PacifiCorp	10.50%	N
03/10/2005	Missouri	Empire District Electric	11.00%	Y
03/24/2005	New York	Consolidated Edison New York	10.30%	N
03/29/2005	Vermont	Central Vermont Public Service	10.00%	N
03/31/2005	Texas	Texas-New Mexico Power	10.25%	Y
04/07/2005	Arizona	Arizona Public Service	10.25%	Y
05/18/2005	Louisiana	Entergy Louisiana	10.25%	Y
05/19/2005	Oregon	Idaho Power	10.00%	N
05/25/2005	New Jersey	Jersey Central Power & Light*	9.75%	N
05/25/2005	Georgia	Savannah Electric & Power	10.75%	Y
05/26/2005	New Jersey	Atlantic City Electric*	9.75%	N
06/08/2005	New Hampshire	Public Service New Hampshire	9.62%	N
07/19/2005	Wisconsin	Wisconsin Power and Light	11.50%	Y
08/05/2005	Texas	Cap Rock Energy	11.75%	Y
08/15/2005	Texas	AEP Texas Central	10.13%	Y
09/28/2005	Oregon	PacifiCorp	10.00%	N
12/12/2005	Wisconsin	Madison Gas & Electric	11.00%	Y
12/13/2005	Oklahoma	OGE Energy	10.75%	Y
12/16/2005	California	San Diego Gas & Electric	10.70%	Y
12/16/2005	California	Pacific Gas & Electric	11.35%	Y
12/16/2005	California	Southern California Edison	11.60%	Y
12/21/2005	Ohio	Cincinnati Gas & Electric	10.29%	
12/21/2005	Washington	Avista	10.40%	Y
12/22/2005	Wisconsin	Wisconsin Public Service	11.00%	Y
12/22/2005	Michigan	Consumers Energy	11.15%	Y
12/28/2005	Kansas	Kansas Gas & Electric	10.00%	Y
12/28/2005	Kansas	Westar Energy	10.00%	Y
12/30/2005	Massachusetts	NSTAR*	10.50%	N
01/05/2006	Wisconsin	Northern States Power	11.00%	Y
01/25/2006	Wisconsin	Wisconsin Electric Power	11.20%	Y
01/27/2006	Connecticut	United Illuminating	9.75%	N
02/03/2006	Colorado	Public Service of Colorado	10.50%	Y
03/03/2006	Minnesota	Interstate Power and Light	10.39%	Y
03/14/2006	Kentucky	Kentucky Power	10.50%	N
04/17/2006	Washington	PacifiCorp	10.20%	N
05/01/2006	Nevada	Sierra Pacific Power	10.60%	Y
05/12/2006	Idaho	Idaho Power	8.1% overall return	Y
05/17/2006	California	Southern California Edison	11.60%	Y
06/06/2006	Delaware	Delmarva Power & Light	10.00%	N
06/27/2006	Michigan	Upper Peninsula Power	10.75%	Y
07/06/2006	Maine	Maine Public Service	10.20%	N
07/24/2006	New York	Central Hudson Gas & Electric*	9.60%	N
07/26/2006	West Virginia	AEP West Virginia	10.50%	Y
07/28/2006	Illinois	Commonwealth Edison	10.05%	
08/23/2006	New York	New York State Electric & Gas*	9.55%	N
09/01/2006	Minnesota	Northern States Power	10.54%	Y
09/14/2006	Oregon	PacifiCorp	10.00%	N
		Average	**10.47%**	

* Transmission and Distribution only utilities

Data comes from Regulatory Research Associates

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. My name is Thomas M. Zepp and my business address is Utility Resources, Inc., 1500 Liberty Street, SE, Salem Oregon, 97302.

Q. Did you prepare rebuttal testimony in this case?

A. Yes.

Q. What is the purpose of this testimony?

A. Portland General Electric Company (PGE) asked me to review the surrebuttal testimonies of Mr. Brian Conway (Staff 1300) and Mr. Thomas Morgan (Staff 1400 and Staff 1401) and respond where I thought it was appropriate.

Q. Please summarize your testimony.

A. My testimony includes the following points:

- Mr. Conway's critique of the PGE's risk positioning model is misplaced, and relies on complicated arguments to obscure the basic point that the PGE's model provides useful information.
- Mr. Morgan's recommendations to the Commission to disregard other sources of information, such as return on equity (ROE) decisions from other commissions and risk premium analyses, would unwisely exclude relevant data that should be considered in evaluating the reasonableness (or unreasonableness) of Mr. Morgan's ROE recommendation.
- Mr. Morgan relies heavily on the techniques of an extreme low-end cost of capital witness, Dr. Randy Woolridge, whose testimony in other proceedings has been demonstrated to be capricious.

- Mr. Morgan's criticisms of my DCF and Risk Premium analyses are unfounded.
- The DCF analysis upon which Mr. Morgan relies for his updated 9.4% ROE recommendation, presented in his Exhibit Staff/1401, Morgan/7, contains two significant errors that result in an understatement of required ROE.
- Mr. Morgan's use of geometric returns rather than arithmetic returns is based on a fundamentally incorrect concept, and is contrary to the weight of authority of financial experts on this issue.
- Mr. Morgan's rejection of "sv" growth is contrary to Commission precedent and the weight of authority of financial experts on this issue.
- The Capital Asset Pricing Model (CAPM) offered by Mr. Morgan is a primitive and flawed "reasonableness" check that should be given no weight by the Commission.
- A more revealing "reasonableness" check is the hammering that PGE's stock price would sustain under Mr. Morgan's 9.4% ROE recommendation, which apparently is intended to drive the market price down to book value. Given that PGE's current market price is 1.29 times book value, if this market price were driven down to book value in one year, Mr. Morgan's recommendation would produce a drop in PGE's stock price of 22.5%.

II. Response to Conway Testimony

Q. Do you have any responses to Mr. Conway?

A. Yes. While PGE is providing a more complete response to Mr. Conway, I have two general observations. My first general observation is a simple point in evaluating the merits of a model, such as the risk positioning model presented by PGE. This point is illustrated in the following quotation by Nobel Laureate Milton Friedman:

> A hypothesis is important if it "explains" much by little, that is, if it abstracts the common and crucial elements from the mass of complex and detailed circumstances surrounding the phenomena to be explained and permits valid predictions on the basis of them alone. To put this point less paradoxically, the relevant question to ask about the "assumptions" of a theory is not whether they are descriptively "realistic," for they never are, but whether they are sufficiently good approximations for the purpose at hand. (Milton Friedman, "The Methodology of Positive Economics," Essays in Positive Economics)[1]

The risk positioning model[2] is an example of a model that "explains much" with a little. It is not only based on common sense but also supported by theory presented by Gordon and Halpern ("Bond Share Yield Spreads Under Uncertain Inflation," *American Economic Review*, 66: 4 (September-1976) pp. 559-565). PGE's model simply states the risk premium required by investors is related to the interest rate. A model need not be "complicated" to be one that is useful, provides perspective and is consistent with the Friedman quotation.

The second observation is that risk positioning models are commonly used by expert witnesses in estimating a utility's required cost of capital, and the PGE model is not unique. Over the years I have presented many versions of the risk positioning model in numerous

[1] I originally presented this quotation to the Oregon Public Utility Commissioner in UF-3335 (Cascade Natural Gas Case) in September 1977 (Zepp D 41) and other cases when I was on the Staff of the Commission.
[2] Here and throughout my testimony, I refer to the risk positioning model as the type of risk premium model used by PGE in this case.

rate cases involving gas utilities, water utilities, and electric utilities. Dr. Hadaway has presented similar risk positioning models before this and other commissions. And I am aware that prominent economist Roger Morin (who wrote the widely quoted book *Regulatory Finance Utilities' Cost of Capital*, Public Utilities Reports, 1994) presented risk positioning models in testimony before regulatory commissions in several states, as has noted financial analyst, William Avera.

III. Response to Morgan Testimony

Q. How do you respond to Mr. Morgan's testimony at Staff/1400, Morgan/12 regarding the weight to be accorded ROE decisions from other jurisdictions?

A. Mr. Morgan explains why he recommends no weight be given to return on equity (ROE) decisions made in other jurisdictions. I have two responses. First, in my view, ignoring such information is inconsistent with the *Hope* and *Bluefield* decisions of the U. S. Supreme Court. In effect, those decisions require the Commission to set rates and establish rate adjustment mechanisms that give PGE a reasonable chance to earn its cost of equity. That cost of equity is the opportunity cost of equity available to investors who can invest in utilities having comparable risk. The most obvious data about that opportunity cost of equity are the ROEs authorized and being earned by those comparable risk utilities. While I agree with Mr. Morgan that the Commission should not cede its authority to set the ROE for PGE, no one is suggesting that; such a situation would happen only if the Commission did not consider authorized and earned ROEs *in conjunction with* other information. There is a wealth of information available to estimate required ROEs. However, Mr. Morgan limits his inquiry to three versions of the discounted cash flow (DCF) model. In many other jurisdictions, required ROEs are determined after consideration of (1) changes in interest rates, (2) risk premium models, (3) capital asset pricing models, (4) DCF models, and (5) other information. (*See*, for example, California PUC D.02-11-027, an interim opinion on rates of return on equity for PG&E, Southern California Edison, Sierra Pacific Power Company, and San Diego Gas & Electric Company). As I explained in my rebuttal, a major benefit of looking at earned ROEs and authorized ROEs is the perspective it provides. Such returns represent the returns being earned and authorized for comparable risk utilities. If indicated ROEs produced with the Staff models are substantially lower than those ROEs, it may indicate that the models or the assumptions being put into those models are inappropriate.

Second, Mr. Morgan contends the relevance of using data on ROE decisions from other states in the PGE risk positioning model is a different issue. This does not "overlap" with the issue of whether the Commission should give weight to *currently* earned and authorized ROEs for comparable risk utilities. Undoubtedly, regulatory commissions in other states take their responsibility to determine ROEs seriously and, in contested cases, probably considered some combination of equity costs determined with risk positioning models and DCF models, changes in interest rates, and other market information presented by various parties when they determined such equity costs. The data points used in the risk positioning model are the *outcomes* of those commission deliberations about such market information. Those data show how much more risky the commissions determined equity to be than whatever measure of debt is used in the analysis when interest rates are at different levels. Contrary to what Mr. Morgan states at Staff/14, Morgan/12 line 16, commissions in litigated cases can be expected to rely upon market information to determine equity costs. The model demonstrates, through looking at other authorized ROEs, how the risk premiums change as interest rates change.

Q. Do you agree with Mr. Morgan's statement at Staff/1400, Morgan/26, that "a cursory review" of PGE/2110, Zepp/1 clearly shows the risk premium from year to year is not constant?

A. No. I discuss PGE/2110, Zepp/1 in my testimony at PGE/2100, Zepp/35. The annual risk premiums shown on PGE/2110, Zepp/1 are annual *realized* risk premiums, not *expected* risk premiums. These data do not indicate whether the expected risk premium was increasing or decreasing during the period and provide no basis to evaluate Mr. Morgan's contention that expected risk premiums have decreased.

Q. At Staff/1400, Morgan/30-32, Mr. Morgan summarizes equity cost studies and opinions of Dr. Randy Woolridge. Do you have any response to that testimony?

A. Yes, I have two responses. First, Dr. Woolridge is not a witness, and thus PGE does not have an opportunity to challenge his testimony in the hearing room. However, since Mr. Morgan has devoted three pages of his testimony to materials provided by Dr. Woolridge, that information should be put in perspective.

Last year Dr. Woolridge was hired by the California Department of Ratepayer Advocates (DRA) as an outside witness in the San Gabriel Valley Water Company case (California PUC Application 05-08-021). In November 2005, methods and data he used produced a cost of equity for a typical water utility that was 85 to 90 basis points lower than in-house DRA Staff witnesses determined to be the cost of equity for a typical water utility in CPUC A.05-02-005 (Apple Valley Ranchos) in June 2005 and CPUC A.05-08-034 (Suburban Water Systems) in November 2005.

Second, I presented rebuttal to Dr. Woolridge in the San Gabriel Water Company case. I rebutted (1) Dr. Woolridge's comments about Value Line projections producing expected returns well above actual returns with the data in PGE/2107, Zepp/1, and (2) his testimony that Mr. Morgan reports at Staff/1400, Morgan/31. PGE Exhibit 2801 includes this testimony. Since Dr. Woolridge is not here to stand cross examination on those points, it is necessary to include this rebuttal testimony in this proceeding to provide some basis for evaluating the unreasonableness of Dr. Woolridge's testimony.

Q. At Staff/1400, Morgan/32-33, Mr. Morgan discussed the use of spot prices for purposes of his dividend yield calculation. Did he address the concerns you raised at PGE/2100, Zepp/25-27?

A. No, he did not. A critical point I made is there are no estimates of spot growth rates and thus an analyst using spot prices may be using growth rates that investors did not rely upon when they priced stocks at the current level. This critical point in my testimony at PGE/2100, Zepp/25-27 stands un-rebutted.

I also pointed out that spot prices may create arbitrary equity cost estimates and, though I expect markets ultimately reflect all available information about stocks, they are not as efficient as is assumed by Mr. Morgan.

Q. At Staff/1400, Morgan/34, Mr. Morgan lists a number of companies that use the "DCF model." Do you have a response to this testimony?

A. Yes, his testimony is puzzling. My testimony makes a clear distinction between the constant growth DCF model and the valuation model below (see PGE/2100, Zepp/16):

$$(1)\quad P_{buy} = CF_1/(1+d) + CF_2/(1+d)^2 + \ldots + CF_n/(1+d)^n,$$

(where P_{buy} is the price the investor would be willing to pay; CF_1, CF_2, . . . CF_n are the cash flows the investor expects to receive in periods 1, 2, . . . n, respectively; and d is a risk adjusted discount rate, the opportunity cost of capital that the investor determines should be used to discount the cash flows). The constant growth DCF model is derived from that valuation model

$$(2)\quad \text{Equity cost} = D_1/P_0 + g$$

(where D_1 replaces CF_1, "equity cost" replaces d and it is assumed cash flows are limited to dividends and grow at a constant rate). Other variations of the DCF model such as the 3-

stage 40-year DCF model presented at Staff/1002, Morgan/6 make similar but somewhat different assumptions.

Mr. Morgan's testimony suggests companies (such as Berkshire Hathaway) use equation (2) in their course of business. Actually, they use equation (1), which is not the "DCF model." It is inappropriate to imply that equation (1) and (2) are simply interchangeable versions of the same thing, when they definitely are not.

To derive equation (2), numerous assumptions must be made about investors. I listed three of those in footnote 2 of my rebuttal. Other assumptions are that (a) market prices are equivalent to the present value of cash flows investor expect, (b) the discount rate is the cost of equity, (c) investors expect the cost of equity to remain constant in the future periods, (d) cash flows relevant for the calculation are dividends, (e) investors do not expect any variation in the growth of dividends, (f) variation in inflation will not occur, (g) planned sale price is also dependent upon future dividend growth, and (h) dividends are expected to grow at a constant rate for an indefinite future period. (Kolbe, Read and Hall *The Cost of Capital Estimating the Rate of Return for Public Utilities*, (MIT Press 1986), pages 53-65). Myron Gordon, who formally derived the DCF model in *The Cost of Capital to a Public Utility* (MSU Public Utility Studies 1974), set forth many more assumptions when he derived the DCF model.

My point is not to criticize the DCF model by pointing out that it is based on many key assumptions; as illustrated in the quotation from Milton Friedman I presented above, assumptions and abstractions are always going to accompany a useful model. My point is that there are other useful models based on different assumptions that may better reflect the way investors' price stocks. Roger Morin stated it this way:

> No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement errors and vagaries in individual companies' market data. The advantage of using several different approaches is that the results of each one can be used to check the others. (Direct Testimony of Roger Morin, Re: MidAmerican Energy Company, Iowa Docket No. RPU-01-3, page 55)

Q. At Staff/1400, Morgan/35, lines 7-14, Mr. Morgan states he does not respond to the equity cost model you presented at PGE/2109, Zepp/1 because (a) you did not outline the assumptions of the model, (b) you did not provide the underlying data for verification, (c) the analysis is based only on data for the last ten years, and (d) those data are earned returns on equity. Do you have a response?

A. Yes. I outlined the assumptions of the model in my testimony at PGE/2100, Zepp/33-34. I state clearly that the equity cost estimates are averages of earned ROEs for the utilities in his sample and that the California DRA deem annual averages of such earned ROE estimates to be useful indicators of the underlying costs of equity in different years. Mr. Morgan apparently does not agree with the DRA Staff that past earned ROEs are useful indicators of the required ROE, but that is not the point. The point is that another ratepayer advocate agency has concluded that such data are useful measures of the cost of equity.

Second, I do not understand his comment about me not providing the underlying data for verification. Some of the utilities in Mr. Morgan's sample were in mergers during the ten year period. The electronic version of Exhibit 2109 includes those predecessors and the cells show how averages of realized returns for those predecessors were computed. Mr. Morgan did not ask for the electronic versions of my exhibits, however, they were subsequently supplied in a supplemental response to OPUC Data Request No. 573.

Third, California DRA Staff uses 10 years in the risk premium analyses they conduct. If Mr. Morgan thought a longer period would be more appropriate, he could have looked up the data for the earlier years. If he thought a shorter period was appropriate, he could have relied on less data than I provided.

Fourth, Mr. Morgan apparently disagrees with California DRA Staff regarding the use of earned ROEs in an equity cost analysis. That is his opinion. In any event, it is important that the Commission be made aware (1) that other reasonable approaches to ROE determination, used by other state agencies, produce ROEs that are much higher than the ROE produced with his various versions of the DCF model, and (2) of Mr. Morgan's opinion that other models should be given no weight.

Finally, at Staff/1400, Morgan/35 lines 13-14, he says the analysis in PGE/2109, Zepp/1 "suffers some of the same problems as PGE's initial risk premium model." I have two responses. First, I addressed his concern at PGE/2100, Zepp 34, line 22 to Zepp/35, line 35. I specifically explain why that is not the case. Earned ROEs result from "all of the components" involved in setting rates and thus PGE/2109, Zepp/1 takes away Staff's primary complaint about using a risk positioning model based on authorized ROEs. Second, PGE/2109, Zepp/1 shows there is a reasonable basis to conclude Mr. Morgan's sample has a forward-looking required ROE that falls in a range of 10.8% to 11.3% and that method stands un-rebutted.

Q. Turning to Staff/1400, Morgan/36, do you have any response to Mr. Morgan's comments about the equity cost you presented for a sample of water utilities?

A. Yes. Mr. Morgan states I did not demonstrate the water utilities sample was comparable to PGE. It did not occur to me that such a formal demonstration was necessary because data

Mr. Morgan provided in Staff/1003, Morgan/119-120 show the water utilities are less risky than PGE. All of the water utilities in the sample that have a bond rating are rated A- or higher and thus are rated higher than PGE. All of the water utilities have business profiles in a range of 2 to 4, which also indicates they are less risky than PGE (which has a business profile of 5). As a result, the evidence in PGE/2104, Zepp/1 provides a conservative estimate of PGE's required ROE.

Second, Mr. Morgan says an average growth of 7.71% seems to be an extremely high level of growth for a DCF model. And without explanation, he suggests that such a growth rate "seem[s] spurious" if it is higher than the growth rate for the overall economy. He also implies such a growth rate is not reasonable unless it is somehow "supported" by historical growth. While I do not agree that historical data are required to validate the 7.71% rate, indeed such historical data are not inconsistent with it. The average growth rate for book values per share, stock prices, dividends per share, and earnings per share—which should all grow at the same rate in equilibrium—was 6.9% during the last 10 years. Value Line explains why future growth is expected to be higher than past growth due to companies in the sample acquiring smaller water utilities that must make major investments but do not have access to financial markets.

Q. Do you have response to his criticism of PGE/2108, Zepp/1 regarding the Value Line forecasts of risk premiums?

A. Yes. At lines 11-22 of Staff/1400, Morgan/36, he makes two criticisms. One is that data and studies he has accumulated show the economy will grow slower than he says is indicated by PGE/2108. Mr. Morgan does not, however, explain why the Value Line projections are at odds with the data he relies upon. Second, he refers to Staff/1003, Morgan/200 to criticize Value Line projections. I rebutted a similar argument by Dr. Woolridge in my testimony in San Gabriel Valley's rate case which I previously discussed above. Data in PGE/2107, Zepp/1 is part of my rebuttal of Dr. Woolridge. Another point is that Value Line is in the business of providing what it believes are accurate projections and data. They have no interest in producing biased results and would expect to lose subscribers if they did.

Q. At Staff 1400, Morgan/37, Mr. Morgan criticizes the risk premium model you presented in PGE/2110, Zepp/1 (Mr. Morgan apparently referred to PGE/2101 by mistake at line 4). Do you have any response?

A. Yes. First, with respect to the Moody's sample, I simply do not understand why Mr. Morgan suggests that Staff might be required to verify the usefulness of a sample determined by a major respected investment service. At the time the sample was established, Moody's was certainly capable of determining a sample of representative utilities that reflected the electric utilities industry.

He also suggests the Moody's sample may be too "broad-based." However, I doubt the Moody's sample is more broad-based than the one he relied upon. Mr. Morgan's sample includes utilities with as little as 14% and 31% regulated revenues and utilities with annual revenues ranging from as little as $395 million to as much as $13.9 billion.

Further, I updated the original Moody's analysis with data for utilities that are both in Mr. Morgan's sample and in the original Moody's sample for the period 2001 to 2005. I assume Mr. Morgan has no complaint about those companies since he has already endorsed consideration of them. The market equity costs derived with this sample indicate his DCF estimates understate appropriate guideline costs of equity.

Q. What is your second general response to his criticism of the risk premium model presented in PGE/2110?

A. His calculation of a 9.87% cost of equity from his determination of annual geometric returns from the data in PGE/2110 should be ignored because it is based on the wrong concept.[3] PGE provides an abbreviated discussion of the differences in geometric average annual returns (“G”) and arithmetic average annual returns (“A”) at PGE/2000, Hager – Valach/51. Roger Morin (in his testimony in various jurisdictions and in his widely quoted book <u>Regulatory Finance Utilities’ Cost of Capital)</u>, Brealey and Myers (in their respected textbook, <u>Principles of Corporate Finance)</u> and Ibbotson Associates (in their <u>Valuation Edition</u>) and other authorities agree that arithmetic average annual returns are the most appropriate concept to discount future cash flows. Such a discount rate is the cost of equity. A risk premium derived from "A" will also be the appropriate risk premium to use to determine costs of equity in a risk premium analysis, not "G."

Brealey and Myers provide an excellent example showing why "A" (and not "G") must be adopted in determining the cost of equity. In their example, their fictional entity "Big Oil" does not pay a dividend, has common stock priced at $100 per share and there are equal chances at the end of the year that the stock will be worth $90, $110 or $130 per share. In this example, the expected return is 1/3 of (-10%, +10% and +30%), or 10%. If the expected value of the stock at the end of the year ($110 per share) is discounted by the discount rate of 10%, we get the present value of $100 = $110/1.10 and the 10% is the correct discount rate and the opportunity cost of capital. If investors expect the same potential returns in a large number of future years, the correct discount rate would again be 10% as there would

[3] I have not bothered to check his calculation since it is based on a fundamentally incorrect concept. I do note, however, that 9.87% is certainly much higher than the 9.4% ROE he recommends at this time.

be an equal chance of getting each of those returns. During that same future period, the G would be found by multiplying:

$$G = (.9 \times 1.1 \times 1.3)^{1/3} - 1 = 8.8\%.$$

This potential return, however, is less than the opportunity cost of capital of 10% and investors would not be willing to pay $100 for the stock. The same holds for utilities. If an investor expects to earn only 8.8% when the cost of equity is 10%, the utility would not be able to attract capital on reasonable terms (*i.e.*, the utility could not get investors to pay $100 for new shares of stock).

As shown in the example provided by Brealey and Myers, "A," not "G," must be adopted to determine costs of equity and risk premiums in the risk premium analysis.

Q. Do you have any other comments regarding the use of arithmetic rather the geometric returns?

A. Yes. Adoption of "G" instead of the conceptually correct value of "A" to determine returns, growth rates in the DCF model, and risk premiums for a risk premium model will bias equity cost estimates downward. It is generally recognized that

$$A \approx G + Var(A)/2$$

and thus, "G" will always be less than "A" unless there is no variance in annual returns; and thus, "G" must understate the required ROE. A casual examination of the annual data in PGE/2110 shows that annual returns (A) have been anything but stable and there has been substantial variation in actual returns during this period of time. Investors will not expect stable growth in returns when they hold utility stocks.

Q. With respect to Mr. Morgan's comments about exhibits PGE/2105 and PGE/2106, Mr. Morgan states at Staff/1400, Morgan/38 that the “sv” “factor has the impact of

increasing earnings per share." Is he correct?

A. No. When stock is sold at a price above book value, it increases cash, not earnings per share. Subsequently, the additional cash (from "sv" growth) and retained earnings ("br" growth) both increase book value per share. Earnings per share increase when the retained earnings and cash (from "sv" growth) increase rate base. Mr. Morgan is correct that "sv" growth benefits investors, but misunderstands the process and misunderstands that "sv" growth is not included in earnings. Myron Gordon, the father of the DCF model, fully discusses this process in his book, <u>The Cost of Capital to a Public Utility</u>, MSU Public Utilities Studies, 1974). This is the way I modeled "sv" growth in PGE/2105 and PGE/2106 and thus Mr. Morgan's criticism is without foundation.

Q. Is it unusual for experts to include "sv" growth in estimates of sustainable growth?

A. No. First, I explained in my rebuttal testimony that Commission Staff routinely included "sv" growth in the past. Also, at PGE/2100, Zepp/21, lines 6-12, I provided a quotation from the Federal Energy Regulatory Commission in which the FERC explains that it includes "sv" growth in its estimates of sustainable growth. In addition, "sv" growth is recognized by consumer advocate witnesses as well as by FERC. I testified in a recent Arizona Public Service rate case in which both the Staff of the Arizona Corporation Commission and an outside expert, Stephen Hill, hired by the Residential Utility Consumer Office, presented sustainable growth calculations which included "sv" growth estimates. In response to a Commission Staff data request in this case, I provided a copy of my testimony in that case.

Q. At Staff/1400, Morgan/38, line 13, Mr. Morgan says the terminal growth rate already has "sv" growth in it. Is he correct?

A. No. The “r” in “br” growth relied upon by the FERC is the Value Line forecast of “r” in future periods. FERC converts the “br” growth rate obtained using the Value Line measure of "r" to put the growth rate on a mid-period basis with what is usually called the FERC formula. If "r" already had “sv” growth in it, the FERC would not need to add “sv” growth to its estimate of “br” growth. As I stated above, it is not unusual for expert witnesses testifying for both utilities and for consumer advocate groups to include “sv” growth in their estimates of sustainable growth. There is no foundation for Mr. Morgan’s claim that “sv” growth should not be included in estimates of sustainable growth.

Q. At Staff/1400, Morgan 39, line 4, Mr. Morgan states the primary impact of your analysis is that first stage growth increases to 7.6% in one version and 8.8% in the other. Is he correct?

A. Mr. Morgan is correct that historical average annual growth in earnings per share (EPS) averaged 7.6% during the last ten years and 8.8% in the last 5 years. But growth in cash flows (dividends) received by investors and used to determine the internal rate of return in the first stage of the 40-year analysis is 3% in both analyses. Footnote 3 in each of the tables (PGE/2105 and PGE/2106) reports that the 3% growth rate was used and a check of the actual growth in column [12] shows that indeed I assumed 3% growth—as did Mr. Morgan—in Stage 1.

Q. Do the EPS growth rates impact the analysis?

A. Yes. While those growth rates are never directly “received” by investors in Stage 1, they do lead to increases in the retention ratios used in the second stage of the analysis.

Q. At Staff/1400, Morgan/39, line 14, Mr. Morgan says that those growth rates "contradict all the available sources of growth that [he] identified in [his] initial testimony." Do they?

A. No. The growth rates are actual averages of annual growth in EPS achieved by the 14 utilities in his sample. Those actual EPS values are reported by Mr. Morgan in Staff/1003, Morgan/99 to Staff/1003, Morgan/112. I agree that Mr. Morgan did not specifically identify them in his testimony, but I obtained those actual EPS numbers and calculated the growth rates from the data he presented. Mr. Morgan could have made the same calculations I made but did not. The calculations I made are consistent with growth rates he advises the Commission to consider.

Q. At Staff/1400, Morgan/40, line 2 he states the terminal ROE you relied upon in both version of the model is 12.97%. Is that correct?

A. No. The terminal ROE is the forecasted ROE on year-end equity from Value Line of 12.5%. It is shown very clearly in PGE/2105 and PGE/2106 – my exhibits restating Mr. Morgan's DCF analysis – in column [9]. Possibly Mr. Morgan mistakenly included "sv" growth in his calculation of the 12.97% ROE. I addressed this issue above and explained "sv" growth is not in the Value Line ROE. Neither PGE/2105 nor PGE/2106 included "sv" growth in the estimate of EPS and thus Mr. Morgan's criticism has no foundation.

Q. At Staff/1400, Morgan/40, lines 3-6, Mr. Morgan criticizes the retention ratios you derived by assuming investors expect past growth in EPS would continue into the future. Do you have a response?

A. Yes. The whole point of my two exhibits restating Mr. Morgan's DCF analysis (Exhibits PGE/2105 and PGE/2106) was to show that if assumptions Mr. Morgan said should be considered are in fact considered in the 40-year model, the indicated internal rates of return are substantially higher than Mr. Morgan assumed in his analyses. Apparently Value Line did not assume actual average annual EPS growth rates in the past are expected in the future, and thus Value Line projects lower retention ratios than I derived with the 40-year model. That result does not make the retention ratios I determined "wrong," as Mr. Morgan implies. It means only that if a more complete range of potential realistic assumptions about future EPS growth is the basis for the analysis, the range of retention ratios would include 54.5% and 47.3%.

Q. What was Mr. Morgan's response to the restatement of his DCF analysis in your Exhibits PGE/2105 and PGE/2106?

A. As part of Mr. Morgan's response to PGE/2105 and PGE/2106, he prepared two new tables, presented at Staff/1401, Morgan/7 and Staff/1401, Morgan/9. I reviewed his electronic work papers supporting those two tables and found two significant problems.

First, the ROE of 12.5% he relies upon in column [9] of both tables is a return on *year-end* equity but he multiplied that ROE times *average* book equity. This mistake understates annual earnings for all years in the second stage and thus understates the internal rate of return.

Second, his analysis has a circularity problem because his annual book equity estimates rely upon annual data being calculated for that year. While I do not agree with his model, I did determine the impact of those errors by restating his analyses with returns on beginning of period equity that are multiplied by beginning of period book equity.

With these corrections, his ROE estimates increase by approximately 20 basis points. As I understand his testimony, his recommended ROE of 9.4% relied upon the calculation in

Staff/1401, Morgan/7, which shows an "internal rate of return" of 9.43%. Thus the corrections I made increase his 9.4% ROE to 9.6%.

Q. At line 19 of Staff/1400, Morgan/40, Mr. Morgan states that "the last ten years of growth for my sample did not approach the rate [Zepp] assumes, but averaged less than three percent." Did it?

A. No. He is wrong. It is my understanding that PGE provided my electronic work paper to Mr. Morgan in a response to a data request. The tab titled "Old.EPS" shows how the average annual growth rates were computed. If Value Line or some other source does not report the same growth rates I computed, it is because they computed the historic growth in some other way.

Q. At Staff/1400, Morgan/41, line 20, Mr. Morgan states that historic growth supports only the low-end of his growth rate range. Do you agree?

A. No, I do not. My estimates of growth in Stage 1 in PGE/2105 and Stage 1 in PGE/2106 assume annual averages of past growth in EPS for the sample and estimates of Stage 1 dividends per share (DPS) growth based on Mr. Morgan's assumed growth of 3%. While that combination of assumptions leads to slow initial growth in DPS, DPS growth in the second stage (and in perpetuity) is much higher because the sample utilities are forecasted to have higher retention ratios after Stage 1 because EPS grows faster than DPS. Contrary to Mr. Morgan's contention, if investors expect past growth in EPS to repeat, estimates of future sustainable growth increase.

Q. At Staff/1400, Morgan/43, Mr. Morgan includes a quotation of a past Commission order which concludes that "projections should be used to estimate the sale of newly issued stock." Did you rely upon such projections to estimate "s" or historical

information about past growth of shares of stock?

A. I relied upon the projections reported by Mr. Morgan in Staff/1002, Morgan/11. Apparently these are projections made by Value Line.

Q. Did Mr. Morgan rely on projections of "s" to determine his estimate of the cost of equity?

A. No. Mr. Morgan did not include any estimate of "sv" growth in his estimates of sustainable growth and thus he did not rely on projected or historic values of "s." This is a puzzling quote to find in Mr. Morgan's testimony. It shows Mr. Morgan knows the Commission has relied upon "sv" growth in past cases, but still fails to acknowledge it should be included in sustainable growth rate estimates.

Q. At Staff/1400, Morgan/43, lines 12-13, Mr. Morgan implies you have "misused" the DCF model. Do you have a response?

A. Yes. There are many versions of the DCF model and any particular DCF model is no better than the assumptions on which it is based. I inserted assumptions in one of Mr. Morgan's versions of the DCF model that Mr. Morgan said should be given consideration--but that he did not consider--when he computed the range of DCF estimates he recommended to the Commission. In preparing my rebuttal testimony, I did not criticize any of the assumptions Mr. Morgan made or the sample he chose. PGE witnesses Hager and Valach address those issues. I do show, however, that once a full spectrum of potential investor expectations are considered and combined with the data Mr. Morgan provided in Staff/1003, the 40-year version of the DCF model shows the full range of DCF equity costs Mr. Morgan reports to the Commission in Table 1 of Staff/1000, Morgan/2 should include a required ROE of 10.5%. This demonstration about the DCF model results, however, is only one part of my comments about Mr. Morgan's presentation. The crucial point in my testimony is other models and actual earned and authorized ROEs for his sample companies provide perspective and show his final ROE recommendation is not reasonable.

Q. At Staff/1400, Morgan/43, line 23, Mr. Morgan states that market-to-book ratios above 1.0 imply that investors do not require returns as high as 12.0% to 12.5%. Do you have a response?

A. Yes. There are many reasons investors might price stocks at market-to-book ratios above 1.0. In Docket UM 903 from November 1998, the Commission Staff witness listed the following six reasons a market price could exceed book value even if the utility was expected to earn no more than its authorized ROE: (1) public utility commissions do not issue orders simultaneously in all jurisdictions, (2) not all of a company's earnings are regulated, (3) regulatory expenses, revenue and rate base adjustments may cause accounting returns to differ from those calculated on a rate case basis, (4) actual sales do not equal sales assumed in a rate case, (5) market expected ROEs change frequently while rate case authorized ROEs do not, and (6) regulated subsidiaries constitute only a piece of a holding company pie. In addition, investors may anticipate a merger or acquisition that produces premium prices based on expected synergies and economies of scale. Another reason is that if all or a portion of a utility were condemned investors would expect a court to award condemnation values substantially above book values.

Q. At Staff/1400, Morgan/44, Mr. Morgan states Value Line now forecasts future earned ROEs will be on the order of 11.5%. Would it be appropriate to re-calculate PGE/2105 or PGE/2106 with that single change in assumptions?

A. No. Presumably, if investors rely on Value Line forecasts, a change in projected ROE will have an impact on the price that investors would pay. In addition, factors other than the change in forecasted ROE might also have to be taken into account before the analysis was re-run.

Q. At Staff/1400, Morgan/44-45, Mr. Morgan suggests earned ROEs should be given no weight by the Commission because he expects investors will earn less than such accounting ROEs. Could you provide some perspective for that comment?

A. Certainly. PGE/2103 shows recent earned ROEs and authorized ROEs for Mr. Morgan's sample companies. As I explained in my rebuttal testimony, such ROEs are clear measures of the opportunity costs investors have if they choose to invest in companies in Mr. Morgan's sample. Mr. Morgan, however, advises the Commission to give such information no weight and to instead rely on market measures of equity costs. However, he limits his market measures of the cost of equity to three DCF approaches and rejects other market models, such as the one I present in PGE/2110, Zepp/1. The market cost of equity estimate in PGE/2110, Zepp/1 indicates the guideline cost of equity is 10.75% and that such market costs of equity are close to guideline ROEs currently being earned and authorized in other jurisdictions. PGE requires a higher ROE because it is more risky.

Q. At Staff/1400, Morgan/46, line 7, Mr. Morgan suggests a risk premium of 300 basis points above the cost of "Baa"-rated bonds is acceptable. Do you have a response?

A. Yes. There are two problems with his testimony. One is that a risk premium as low as 300 basis points above the cost of Baa bonds is unreasonable. The risk premium implied when the Commission accepted the 10.2% ROE for NW Natural was 3.54% (10.2% - 6.66% Baa rate) and during the period 1950-2005 averaged 3.55%. (*See* PGE/2110).

Second, the relevant cost of equity in this case is the cost of equity in 2007. Adding either the 3.54% or the 3.55% actual average risk premiums to the expected cost of Baa bonds indicates a guideline cost of equity of 10.74% to 10.75%. As PGE is more risky than NW Natural, the 10.74% ROE is an indicated floor representing the bottom of the range for determining a fair ROE for PGE. But, even if Mr. Morgan's 300 basis point risk premium is added to the expected Baa rate of 7.2%, the indicated guideline cost of equity is 10.2%, substantially in excess of the 9.4% Mr. Morgan recommends.

Q. At Staff/1400, Morgan/46, Mr. Morgan argues against giving any weight to the past ROE adopted by the Commission in UG 152. Do you have a response?

A. Yes. At several places in his testimony, Mr. Morgan urges the Commission to reject solid, conceptually correct analyses, such as the risk positioning analysis presented by PGE, and instead rely on decisions it made in past orders. Mr. Morgan cannot have it both ways. If past determinations by the Commission should have weight today, anything as important as the ROE adopted by the Commission in a relatively recent proceeding should be given weight.

Q. At Staff/1400, Morgan/47, Mr. Morgan states that he addressed the market-value analysis which explains why the results of DCF models are expected to understate ROEs. Did he?

A. No. At Staff/1400, Morgan/35, line17, Mr. Morgan states he plans to address that analysis. At Staff/1400, Morgan/47, line 7, he says he responded to my testimony at PGE/2100, Zepp/27-28, when in fact he did not. The concept is that when investors buy stocks at prices above book value, they are buying a company with much less leverage than is used by a regulatory commission which sets rates with an equity ratio based on book values. The authorized ROE should therefore be adjusted to reflect the difference in market leverage and leverage used to set rates.

Q. In discussing that analysis, you referred to an article by Kolbe, Vilbert and Villadsen published in 2005. Is this a new concept?

A. No. While I did not make a complete literature search, this concept has been discussed as long ago as 2001. In 2002, the Pennsylvania PUC considered the difference in book leverage and market leverage and added 80 basis points to the authorized ROE it set Philadelphia Suburban Company (Docket NO. R-00016750). In making this adjustment, the Pennsylvania PUC stated:

> "We find the financial risk adjustment is indeed necessary to reconcile the divergence between [Philadelphia Suburban Company's] market and book values"

This case was decided in July 2002. As the record in this case stands, this concept is un-rebutted by any party and provides a solid conceptual basis to authorize an ROE for PGE that is 75 basis points higher than is produced with market models of the cost of equity. See my testimony at PGE/2100 Zepp/28, line 5. Based on Staff's corrected 9.6% DCF estimate of the cost of equity, that concept would support a return on book equity for the benchmark sample of 10.35%. Based on the market model estimate of the cost of equity in PGE/2110 Zepp 1, the indicated required ROE on book equity is 11.50%. My testimony at PGE/2100 Zepp/27-28 indicates the equity cost floor for guideline companies is no less than 10.35% and the fair ROE for PGE is higher because PGE is more risky.

Q. At Staff/1400, Morgan/48, Mr. Morgan offers a CAPM analysis as a check on his DCF approaches. Do you have a response?

A. Yes. Cost of capital witnesses for PGE, PacifiCorp, and NW Natural spent considerable effort in previous proceedings demonstrating why little, if any, weight should be given to the CAPM, and the Commission agreed to abandon this approach. Notwithstanding this precedent, Mr. Morgan resurrects it here in his desperation to find corroboration for the extreme results produced by his DCF analysis. Looking at the approach presented by Mr. Morgan – which he himself admits is not "rigorous" – it is easy to see why the method is so controversial and subjective.

The method relies on three values that must be chosen. First, as to the risk-free rate or "zero beta" return, Ibbotson Associates explain why the risk-free rate should be no less than the rate on long-term Treasury securities. The "empirical CAPM" presented by Roger Morin in his testimony relies on empirical tests of CAPM that show the "zero beta" return should be higher than the expected return on long-term Treasury bonds. A ten-year Treasury security rate used by Mr. Morgan will bias downward the CAPM estimate.

Second, no one knows the beta for PGE. Without a beta, the whole "check" is meaningless. Mr. Morgan assumed a beta of .85. Possibly a more appropriate beta is 1.0, the beta for IDACORP, the only Northwest electric utility in his sample.

Third, the estimate of the market risk premium (MRP) is a very controversial issue. Ibbotson Associates report forward-looking expected MRPs based on an historical long-horizon average of 7.1% and a supply side model of 6.3%. Other estimates of the MRP, such as the ones I presented in PGE/2108 could be assumed.

With a long-term Treasury rate of 5.35% (see PGE/2109), Mr. Morgan's chosen beta of 0.85 and the Ibbotson Associates range of MRPs of 6.3% to 7.1%, the indicated range of cost of equity estimates is 10.71% to 11.39%, which is 130 to 200 basis points higher than his recommended ROE for PGE of 9.4%. I do not agree that CAPM should be given any substantial weight, but if it is, it shows Mr. Morgan's equity cost estimate for PGE is significantly below the PGE's required ROE.

Q. Are there other checks on Mr. Morgan's testimony that show Mr. Morgan's recommended ROE of 9.4% is substantially below the ROE required by PGE?

A. Yes. At Staff/1400, Morgan/43-44 and other places in his testimony, Mr. Morgan implies that currently earned and authorized ROEs higher than his recommended ROE of 9.4% are not required by his sample of electric utilities. He states "a market-to-book ratio greater than 1.0 indicates that [his] sample of utilities is expected to earn accounting ROEs greater than the utilities' cost of equity" (Staff/1400 Morgan/45, line 2). Apparently Mr. Morgan believes that if authorized ROEs were set at the 9.4% he recommends (excluding minor earnings from non-regulated operations), his recommendation would drive the market price down to book value. The valuation model behind the DCF model can be simply written as

$$P_o \quad = \quad D_1/(1+k) + \quad P_1/(1+k)$$

where P_o is the current price of stock, k is the discount rate, D_1 are dividends paid next year and P_1 is price at the end of the year. Mr. Morgan indicates the market price of his sample is currently 1.79 times book value (Staff/1401, Morgan/7). PGE's market-to-book ratio was 1.29 at June 30, 2006. If indeed setting the ROE at the 9.4% level drives market prices down to book values and that were to occur in one year, his recommendation would produce a drop in stock price of 44.1%. (-.79 / 1.79) for his sample and 22.5% (-.29/ 1.29) for PGE. It is hard to imagine how investors could expect to earn his 9.4% per year recommended ROE, when he expects the ROE he recommends to drive stock price down by such a huge amount. This "check" clearly shows investors expect an ROE more in line with currently earned and authorized ROEs of other utilities. This check also indicates that whatever assumptions he has made to estimate the 9.4% ROE are invalid if they produce an ROE so much below what other utilities are expecting to earn.

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2801	Zepp Rebuttal Testimony

Application No. 05-08-021

Exhibit No. SG-25 #25

Witness ______________

Date ______________

SAN GABRIEL VALLEY WATER COMPANY

REBUTTAL TESTIMONY OF

THOMAS M. ZEPP

December 2005

REBUTTAL TESTIMONY OF
THOMAS M. ZEPP

I. Introduction, Overview and Conclusions

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Thomas M. Zepp and my business address is 1500 Liberty Street, SE, Salem, Oregon, 97302.

Q. DID YOU PREPARE DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. San Gabriel Valley Water Company ("San Gabriel", "SGVWC" or the "Company") has asked me to review the testimonies of Dr. J. Randall Woolridge, dated November 29, 2005, testifying on behalf of the Office of Ratepayer Advocates "(ORA") and Richard W. Cuthbert, dated November 29, 2005, testifying on behalf of the City of Fontana and respond to their testimonies where appropriate.

Q. HAVE YOU PREPARED ANY TABLES OR ATTACHMENTS THAT ACCOMPANY THIS TESTIMONY?

A. Yes. I have prepared 14 rebuttal tables and 6 attachments that are part of my testimony.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS?

A. My conclusions are:

1. In the past, the Commission has recognized that ORA is a "ratepayer advocate" and that a fair and reasonable ROE for water utilities is generally above recommendations made using ORA's standard financial models.

2. Based on evidence presented by ORA Staff in A.05-02-005 (Apple Valley Ranchos), stipulation dated June 2005, and A.05-08-034 (Suburban Water Systems), dated November 28, 2005, the ROE computed by ORA Staff for its benchmark sample of water utilities is in the range of 9.90% to 9.85%. The ROE computed by ORA Staff must be considered as a floor for fair ROEs for water utilities.

3. Based on the spread above ORA's recommended ROE in San Gabriel's last case (cited by ORA in A.05-02-005) and the updated and corrected November 28, 2005 ORA Staff determination of the fair ROE for its water utilities sample in the SWS GRC, the indicated ROE for San Gabriel is 10.6% (9.90% plus 0.7%).

4. If the CPUC does not adopt SGVWC's actual capitalization ratios to determine rates, it should continue to adopt an equity ratio of no less than 60% to set rates for San Gabriel.

5. The primary flaws in Dr. Woolridge's determination of test year debt costs and costs of equity for San Gabriel are (a) a failure to follow longstanding Commission policy of relying upon forecasted interest rates, (b) reliance on geometric instead of arithmetic returns to determine growth rates and return premiums, (c) failure to use a RP approach as a check on his DCF and CAPM approaches, (d) reliance on CAPM market risk premium estimates that are not generally known by investors, (e) a claim that observed market-to-book ratios for water utilities support reducing authorized ROEs, (f) failure to recognize risk—as measured by betas—has increased for water utilities and such higher risk indicates the ROE for San Gabriel should be increased above 10.10%, not reduced, (g) a lack of familiarity with past methods used by ORA Staff and recognized by the CPUC to determine equity costs for water utilities, (h) failure to recognize the time value of money—as is done by ORA staff—to determine DCF dividend yields, (i) failure to rely on forward-looking estimates of growth in making DCF estimates, (j) an erroneous conclusion that use of analysts' earnings forecasts would bias DCF equity cost estimates.

6. The primary flaws in Mr. Cuthbert's determination of the cost of equity are (a) reliance on unrealistically low growth rates in his DCF analysis, (b) adoption of dividend yields in his DCF analysis that assume growth is half as large in the first future year as growth in all other future years, (c) ignoring the time value of money in his DCF analysis, and (d) reliance on actual instead of forecasted interest rates to conduct his risk premium analysis.

7. In San Gabriel's most recent Fontana Water Company and Los Angeles County division decisions, the Commission found a cost of equity of 10.10% was reasonable. Evidence provided by ORA Staff in A.05-08-034 (SWS's latest GRC) shows the cost of equity for ORA's standard sample of six water utilities has increased since the 10.10% was determined to be reasonable. Evidence in Rebuttal Table 9 shows that estimates of beta risk have increased and thus required ROEs for water utilities have increased. I have provided evidence in my direct testimony and this rebuttal testimony that shows San Gabriel's cost of equity is now much higher than 10.10%.

8. Unadjusted data presented by ORA Staff in the SWS GRC (A.05-08-034) shows that if conceptually correct measures of growth reported by ORA Staff are used to determine DCF cost of equity estimates for ORA's sample of six water utilities, that benchmark cost of equity is 11.6%, 10 basis points higher than the 11.5% ROE requested by the Company.

9. In two prior cases, the CPUC previously rejected a proposal to determine San Gabriel's ROR with a hypothetical common equity ratio that was less than 60%. A common equity ratio of at least 60% is in line with equity ratios authorized for other relatively small Class A water utilities. Mr. Cuthbert's recommended hypothetical capital structure with a 50% equity ratio should be rejected.

10. San Gabriel faces above-average risk because of its size and other factors that both Mr. Whitehead and I addressed in our direct testimonies. In Decision 04-07-034, the Commission found that San Gabriel required a risk premium of 67 basis points above ORA's 9.43% cost of equity estimate for its sample water utilities. More recently, the Commission found that a 70 basis point premium above ORA's recommended ROE of 9.40% was reasonable. I explain why 67 and 70 basis points are conservative measures of the compensation required to properly compensate for added risk faced by San Gabriel and why the adder should be 120 basis points.

Q. WHAT HAS DR. WOOLRIDGE RECOMMENDED?

A. Dr. Woolridge recommends the Commission adopt a hypothetical capital structure for San Gabriel which contains 40% debt and 60% equity, San Gabriel's estimated debt cost of 8.42% for 2005 for all years under consideration, and an equity cost of 9.0%.

Q. PLEASE PUT DR. WOOLRIDGE'S TESTIMONY ON ROE IN PERSPECTIVE.

A. Dr. Woolridge is an outside consultant testifying on behalf of ORA. The day before Dr. Woolridge filed his testimony in this case, his client filed ROE testimony in Suburban Water Service's ("SWS") general rate case ("GRC") (A.05-08-034, Report on the Cost of Capital of Suburban Water System, dated November 28, 2005) using methods ORA has relied upon to determine equity cost estimates in numerous water utility cases during the last three years. Once the average of interest rate forecasts relied upon in the SWS case are updated and revised to reflect the period in which SWS's new rates will be in effect and data for equity returns in the risk premium analysis are made consistent with past ORA reports, the indicated cost of equity is 9.90%–90 basis points higher than Dr. Woolridge proposed for San Gabriel. This 9.90% ROE estimate for SWS is in line with a 9.85% ROE ORA stipulated was the ROE that would be produced with its financial models for the same sample of six water utilities used by ORA Staff in the SWS case (Stipulation in Application 05-02-005 for Apple Valley Ranchos GRC, dated June 2005)[1]. Based on the large differences between his equity cost estimate and equity costs that are produced with the standard ORA financial models, it is obvious that whatever Dr. Woolridge has done to produce a 9.0% ROE is not credible. In Section II of my testimony, I present an update and review of the SWS cost of equity estimate.

In Section IV of my testimony, I respond to Dr. Woolridge. I present an analysis of the approaches he uses to support the 9.0% ROE and explain the

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[1] In Application 05-02-005, ORA stipulated as follows:

> "The parties agree to stipulate that the staff financial models used by ORA to determine Return on Equity (ROE), when updated to incorporate more recent information available as of May 2005, produce a ROE of 9.85% for the "Comparable Group" of publicly-traded regulated water companies used by ORA in those financial models."

primary flaws in those methods that allow him to create such a low estimate of the cost of equity. In past cases, ORA has determined costs of equity for water utilities by giving a 50% weight to equity costs determined with the DCF model and a 50% weight to equity costs made with a risk premium ("RP") model. In determining his 9.0% equity cost estimate, Dr. Woolridge uses the DCF model and the capital asset pricing model ("CAPM"), but rejects any reliance on risk premium models such as the ones the ORA Staff has previously presented. He asserts that the level of market-to-book ratios for water utilities supports the reasonableness of his 9.0% ROE estimate.

Q. PLEASE PUT HIS DEBT COST APPROACH IN PERSPECTIVE.

A. Dr. Woolridge is apparently unaware that for many years the CPUC has based future interest rates estimates on forecasts of interest rates for both energy and water utilities. He rejects the Company's proposal to base debt costs in 2006, 2007, 2008, and 2009 on forecasted interest rates because it is his opinion that long term forecasts are not reliable or accurate and he is unaware of any studies that indicate otherwise (Woolridge, page 10). In section IV below I present a study by the Arizona PSC Staff that found forecasts of interest rates are not biased. Dr. Woolridge does not explain why San Gabriel's proposed debt cost of 8.42% for 2005 is expected to provide a reasonable forecast of interest in 2006, 2007, 2008, and 2009 when interest rates are generally expected to increase.

Q. WHAT HAS MR. CUTHBERT RECOMMENDED?

A. Mr. Cuthbert recommends an 8.9% ROE, an equity ratio of 50%, and projected debt cost for San Gabriel's series Q and R issues of 7.99% and 8.66%. Mr. Cuthbert's revisions in the Company's projected debt costs are limited to his opinion about what the issuance expenses should be, not the underlying projected coupon costs of debt.

Q. PLEASE PUT MR. CUTHBERT'S CAPITAL STRUCTURE RECOMMENDATION IN PERSPECTIVE.

A. In Decision 04-07-034, dated July 7, 2004 the California Public Utilities Commission ("Commission" or "CPUC") found that San Gabriel required a common equity ratio of no less than 60%. Subsequently, in Decision 05-07-044 dated July 21, 2005, the Commission again adopted a 60% common equity ratio for San Gabriel that was agreed to in a settlement between ORA and the Company. Mr. Cuthbert ignores all of this past history and recommends penalizing the Company by proposing a 50% equity ratio. As discussed below in section III, Mr. Cuthbert's recommendation is arbitrary and inconsistent with capital structures this Commission has previously found to be reasonable for not only San Gabriel but also a number of other water utilities. Dr. Woolridge recommends a 60% equity ratio be adopted in this case. Mr. Cuthbert's recommendation has no merit and should be given no consideration.

Q. PLEASE PUT MR. CUTHBERT'S ROE RECOMMENDATION IN PERSPECTIVE.

A. Certainly. At page 5 of his testimony, Mr. Cuthbert claims the ROE analyses he presents are consistent with analyses relied upon by the Commission in Decision 04-07-034 (San Gabriel's order). He also claims the methodology he uses in his rate of return analyses are consistent with recent decisions the Commission made to determine required ROEs for water utilities. He is wrong. In ORA's Report on Results of Operations of Apple Valley Ranchos Water Company, Application 05-02-005, dated May 20, 2005, ORA prepared Table 13-3 showing the following:

Company	ORA Proposed ROE	Company Proposed ROE	Approved ROE
San Gabriel	9.40%	12.00%	10.10%
Cal-American	9.40%	10.50%	9.85%
Cal-Water Service	9.61%	12.15%	10.10%

San Gabriel's approved ROE of 10.10% was 70 basis points higher than the ROE recommended by ORA of 9.4%. The authorized ROEs for California American and California Water were 45 and 49 basis points higher than ORA recommendations. In section II, I show that once the ORA proposed ROE of 9.57% in the Suburban Water System case is made consistent with methods and data ORA used in past cases and interest forecasts are based on the November 2005 (instead of September 2005) DRI forecast, the ORA Staff proposed ROE would be 9.90%. If indeed Mr. Cuthbert had used methods consistent with "recent decisions made by the Commission for determining required return on equity for water utilities" (Cuthbert, page 5), he would have recommended an ROE that is higher than San Gabriel's currently authorized ROE of 10.1%, not 8.9%. In Section IV and V, I address the flaws in Mr. Cuthbert's equity cost estimates that allows him to create an ROE as low as 8.9%.

II. ORA Staff's November 28, 2005 Estimate of the Cost of Equity for SWS.

Q. HAS ORA STAFF MADE A RECENT ESTIMATE OF THE COST OF EQUITY FOR ITS WATER UTILITIES SAMPLE?

A. Yes, it has. For a number of years, ORA has applied standard DCF and RP models to data for a sample of six water utilities to determine a benchmark cost of equity for water utilities. Those six water utilities are American States, Aqua America, California Water, Connecticut Water Service, Middlesex Water and SJW Corp. ORA staff used those standard financial models and the ORA sample of six water utilities to make an equity cost estimate for this benchmark sample in the Suburban Water System ("SWS") GRC (A.05-08-034) in Report on the Cost of Capital of Suburban Water System, dated November 28, 2005 ("SWS Report").

Q. HAVE YOU REVIEWED THE SWS REPORT?

A. Yes, I have. In that Report, ORA uses its standard DCF model to determine an equity cost of 9.27%, and an RP model using a September DRI forecast of interest rates to estimate an RP estimate of the cost of equity of 9.88%. As in past cases, ORA took the simple average of those two equity cost estimates and determined an equity cost for the benchmark sample of 9.57%.

Q. DID YOU OBSERVE ANY INCONSISTENCIES WITH THE ESTIMATES IN THE SWS REPORT AND ORA ESTIMATES OF THE COST OF EQUITY YOU HAVE REVIEWED IN PAST CASES?

A. Yes. While I do not agree with the method ORA uses to determine equity costs with the DCF model, the implementation of the DCF model in the ORA SWS Report was consistent with past ORA estimates I have reviewed. The RP model, however, was not.

Q. PLEASE EXPLAIN REBUTTAL TABLE 1.

A. Rebuttal Table 1 summarizes the estimates of average current dividend yields (ORA Table 2-2 in the SWS Report), average historic growth rates (ORA Table 2-3 in the SWS Report) and an average of analysts' forecasts of growth (ORA Table 2-4 in the SWS Report) ORA Staff witness Mr. Aslam relied upon in his DCF analysis. Estimates of those variables for each of the six water utilities that were used to construct the averages I report in Rebuttal Table 1 can be found in the SWS Report. I have included these summaries of the ORA Tables in the SWS Report for comparison with methods Mr. Cuthbert and Dr. Woolridge used to make their DCF estimates. One difference is that ORA recognizes the time value of money when it computes current dividend yields (D_0/P_0) but Dr. Woolridge and Mr. Cuthbert do not. The choice by Dr. Woolridge and Mr. Cuthbert to not recognize the time value of money biases their DCF equity cost estimates downward.

Q. WHAT IS REBUTTAL TABLE 2?

A. Rebuttal Table 2 shows the way ORA combines the data it presented in Tables 2-2, 2-3, and 2-4 (reproduced here in Rebuttal Table 1) to make its DCF equity cost estimates. ORA determines (D_1/P_0) as I have defined it in my direct testimony in Equation (2) of my direct testimony at page 29. Both Mr. Cuthbert and Dr. Woolridge increase (D_0/P_0) by one-half the growth rate to compute their estimates of D_1/P_0. ORA Staff and I correctly increase D_0/P_0 by our full growth estimates of (g). This is required, as I explain at page 29 of my direct testimony, to be consistent with the valuation model (equation 3, page 29 in my direct testimony). The choice made by Dr. Woolridge and Mr. Cuthbert produces a bias that reduces their DCF equity cost estimates.

In estimating growth for its DCF estimates, ORA Staff takes a simple average of estimates of past growth and forward-looking estimates of growth. Based on this approach, ORA concludes the DCF equity cost is 9.27%. I disagree with ORA's inclusion of past growth in the average and will I return to this issue below.

Q. PLEASE TURN TO YOUR COMMENTS ABOUT ORA STAFF'S RISK PREMIUM EQUITY COST ESTIMATE.

A. I have made three revisions in the ORA RP analysis to make the one in A.05-08-034 consistent with past RP estimates. First, I have used the November 2005 instead of the September 2005 DRI forecast to update the ORA Staff analysis. It is appropriate to rely on the more recent DRI forecast. ORA Staff and the Commission routinely use DRI forecasts to develop forecasted interest rates and to make RP estimates. Second, SWS will not put new rates in place until mid-2006 and thus interest rates that exist in 2005 (or some combination of actual and forecasted rates for 2005) are not relevant for the RP cost of equity analysis. The correct period is 2006-2009. My Rebuttal Table 3 reports an updated average of the interest rate forecasts for the relevant period, 2006 to 2009. This updated average of interest rates for 2006-2009 should be adopted in the RP analysis to be consistent with past ORA Staff presentations.

Third, I compared the average annual ROE values Mr. Aslam presents in Table 2-7 in the report on Cost of Capital in A.05-08-034 with comparable average ROE values ORA's witness presented in A.04-04-040 (California American, November 2004) for the years 1995 to 2003. I was a witness in A.04-04-040. In that case, I reviewed those values, discussed the source of the underlying data with the ORA witness, and was convinced she obtained those values from reasonable sources. Based on that past review, I restated Mr. Aslam's RP analysis with the average annual ROE values for 1995 to 2003 ORA relied upon in A.04-04-040. I have also replaced Mr. Aslam's average annual ROE value for 2004 with an average ROE that I extracted from data in Annual Reports to Stockholders and 10-K reports.

Q. WHAT IS THE RESULT OF YOUR RESTATEMENT OF HIS RP ANALYSIS?

A. The average cost of equity indicated by the ORA RP approach increases from 9.88% to 10.53%, an increase of 65 basis points. See Rebuttal Table 4.

Q. WHAT IS SHOWN IN REBUTTAL TABLE 5?

A. Rebuttal Table 5 is my restatement of ORA Staff's Table 2-8 in A.05-08-034. In making this restatement, I have not revised Mr. Aslam's DCF estimate, though I disagree with the concepts he relied upon to make that estimate. The only revision is from the updates and revisions of data for the RP estimate of the cost of equity that I have explained above. With the corrected RP analysis, the indicated ORA cost of equity for the comparable group increases to 9.90%. This updated ROE estimate for the ORA Staff water utilities sample in A.05-08-034 is five basis points higher than the 9.85% ROE ORA stipulated was the equity cost produced by those same financial models in June 2005 (A.05-02-005, Apple Valley Ranchos Water).

Q. DO YOU HAVE ANY OTHER COMMENTS ABOUT THE ORA REPORT THAT STAFF PREPARED FOR SUBURBAN WATER?

A. Yes, as I explained in my direct testimony, DCF estimates of the cost of equity should be based on forward-looking estimates of growth, if they are available. ORA Staff has computed its growth rate as an average of past and forecasted growth. The conceptually correct DCF estimate should be based on the ORA estimate using forward-looking growth.

Q. HAVE YOU COMPUTED THAT DCF ESTIMATE?

A. Yes. It is shown in Rebuttal Table 6 Combining the ORA Staff's estimates of average dividend yields with ORA Staff's estimated average of analysts' forecasts of growth of 8.27% indicates a DCF cost of equity for the ORA sample of 11.62%.

Q. WHAT DOES THIS REVISED DCF ESTIMATE DO TO THE INDICATED COST OF EQUITY FOR THE ORA SAMPLE AND SAN GABRIEL?

A. It increases the indicated cost of equity for the ORA sample to 11.07%. See Rebuttal Table 7. Even if only the 70 basis point risk premium above ORA Staff estimates of the cost of equity are recognized, the indicated cost of equity for San Gabriel is 11.77%.

<u>III. San Gabriel should be authorized an equity ratio of no less than 60%.</u>

Q. MR. CUTHBERT RECOMMENDS THE COMMISSION USE A HYPOTHETICAL CAPITAL STRUCTURE WITH ONLY 50% COMMON EQUITY TO DETERMINE RATES FOR SAN GABRIEL. IS THAT APPROPRIATE?

A. No. Mr. Cuthbert offers no convincing reason to adopt any hypothetical capital structure for San Gabriel. Unless there is compelling evidence to use a hypothetical capital structure, a utilities' actual capital structure should be used to set rates. When an actual capital structure has more equity than the hypothetical capital structure, ratepayers obtain benefits by San Gabriel being able to obtain lower debt costs than the Company could obtain if it had the weaker equity position in the proposed capital structure. In no case should a capital structure with less than a 60% equity ratio be adopted. In D.04-07-034, dated July 8, 2004, the Commission determined that an appropriate capital structure for San Gabriel had no less than 60% common equity. In D.05-07-044, the Commission again found a 60% equity ratio for rate-making purposes was appropriate.

Q. ARE THERE ANY GENERAL STUDIES THAT HAVE FOUND SMALLER COMPANIES REQUIRE HIGHER EQUITY RATIOS THAN LARGER COMPANIES?

A. Yes. The now classic study by Scott and Martin ("Industry Influence on Financial Structure," *Financial Management*, spring 1975, pp. 67-71) found statistically significant results for unregulated firms that show "smaller equity ratios (higher leverage use) are generally associated with larger companies" (page 70). It is reasonable to presume those unregulated firms attempted to seek the best balance between debt, equity, and the tax benefits of debt to obtain the lowest overall cost of capital. The results of their study indicate smaller firms attempting to minimize capital costs will have higher equity ratios to offset higher business risks. In the case of San Gabriel, it is smaller than four of the water utilities in ORA's standard water utilities sample and substantially smaller than the average size water utility used by ORA to determine equity costs. Based on size alone, it is reasonable for San Gabriel to have a higher equity ratio than the average for this benchmark sample of six water utilities.

Q. DOES SAN GABRIEL HAVE OTHER UNIQUE BUSINESS RISKS THAT JUSTIFY THE COMPANY HAVING A HIGHER EQUITY RATIO?

A. Yes, I discuss those other unique risks in my direct testimony. It is reasonable for San Gabriel to reduce its financial risk (have a stronger equity position) to offset these additional business risks and risk of being small. In my direct testimony, I addressed these issues and explained why they add to San Gabriel's risk.

Q. DO YOU HAVE A RESPONSE TO MR. CUTHBERT'S PROPOSAL TO ADOPT A HYPOTHETICAL 50% EQUITY RATIO?

A. Yes. The most obvious response is that the Commission has already examined this issue and found that an equity ratio of no less than 60% is a reasonable equity ratio for rate-making purposes. A 50% equity ratio is not the appropriate, cost-minimizing, capital structure for the Company. San Gabriel must always maintain an equity ratio higher than equity ratios of publicly-traded water utilities of similar size because it has more limited financing flexibility than a publicly traded utility that can issue more common stock shares if needed. Also, the Company requires a strong equity position to be able to sell bonds on reasonable terms and finance expected and unexpected investments in a timely manner. A strong equity position allows San Gabriel to make timely issues of bonds and thus avoid delays in making investments required to meet environmental concerns and maintain its quality of service.

Q. IS THERE A WAY TO EXAMINE WHETHER THE 60% EQUITY RATIO CURRENTLY AUTHORIZED FOR SAN GABRIEL IS MORE "EFFICIENT" THAN THE 50% EQUITY RATIO MR. CUTHBERT PROPOSES?

A. Yes. Solid evidence on that point is what the CPUC has found to be reasonable for other water utilities of similar size. I have examined CPUC orders for San Gabriel and three other small Class A water utilities and found the following:

Company	Equity Ratio	Basis for Equity Ratio
Great Oaks (93 GRC)	66%	Hypothetical
Great Oaks (3/03 Staff Report)	66%	Requested
Valencia (2002 Staff Report)	61.5%	5-year average actual
Park Water (7/2003)	59.98%	Projected actual
Park Water (7/2002)	59.91%	Projected actual
San Gabriel (two cases)	60%	Hypothetical

In the Great Oaks and Valencia cases, the CPUC found that an equity ratio in excess of 60% was appropriate. In the Park Water cases, the CPUC found an equity ratio that rounds to 60% was appropriate. Because San Gabriel has an actual equity ratio much higher than 60% at this time, this evidence supports adoption of an equity ratio of no less than 66% for San Gabriel, but in no case less than the 60% adopted by the Commission in San Gabriel's most recent two general rate cases.

Q. IS AN EQUITY RATIO OF 66% REASONABLE AND APPROPRIATE FOR SAN GABRIEL IN THIS CASE?

A. If the Commission determines that San Gabriel's actual capital structure is inappropriate for ratemaking, a 66% equity ratio is certainly more appropriate than a 50% equity ratio. Mr. Cuthbert suggests that a capital structure with an equity ratio as high as San Gabriel projects it will have during the test years may be inefficient. While he offers no evidence that San Gabriel's actual projected capital structure is inefficient, it is clear from the CPUC decisions above that the CPUC has found that an equity ratio of 60% is not inefficient and an equity ratio of 66% is not inefficient for another Class A water utility. In no case should the adopted equity ratio be less than 60%. The CPUC has authorized, or ORA Staff has recommended, an equity ratio at least as large as 60% in recent cases for relatively small Class A water utilities. Also, nothing has happened since July 2004, when D.04-07-034 was issued, that would justify using an equity ratio smaller than 60%.

A consideration of capital structures for other small Class A water utilities provides a reasonable basis to establish the minimum size equity ratio for San Gabriel. To adopt, as Mr. Cuthbert proposes, an equity ratio that is much smaller than the equity ratios the CPUC and ORA Staff have found to be reasonable for San Gabriel and other Class A water utilities of similar size, is unfair and unreasonable when San Gabriel in fact has an actual equity ratio projected to be above 76% throughout the 2006-2009 period. For the reasons stated above, a 66% equity ratio and no less than a 60% equity ratio is a far more reasonable choice than 50% if the CPUC determines that San Gabriel's actual projected equity ratios are not appropriate for rate-making purposes.

IV. Responses to Dr. Woolridge

Q. PLEASE TURN TO YOUR RESPONSES TO DR. WOOLRIDGE. WHAT IS HIS POSITION ON THE USE OF FORECASTED INTEREST RATES?

A. At page 10 of his testimony, he says he "will not employ these [forecasted interest] rates because it is [his] opinion that long-term interest rate forecasts are not reliable or accurate, and [he is] not aware of any studies that indicate otherwise." Instead he adopts interest rates close to current actual interest rates in 2005 to determine test year equity and debt costs for San Gabriel in 2006, 2007, 2008, and 2009.

Q. DO YOU AGREE WITH HIS POSITION?

A. No, for three reasons. First, authorized equity returns for San Gabriel are determined for 2006-2007, 2007-2008, and 2008-2009 during this GRC and there is effectively no way for San Gabriel to file for higher costs of capital if bond costs or equity costs increase during that future three year period. In other jurisdictions where Dr. Woolridge has testified, he may have observed that utilities are allowed to request higher costs of capital when required. Given procedures established in California that is not the case. To mitigate this added risk faced by California water utilities, it is critical that the best available information be used to set debt costs and equity costs. It does not make any sense to base debt costs and costs of equity for three years on current interest rates when interest rates are generally expected to increase.

Second, it has been Commission policy for many years to determine future test year debt costs and equity costs with forecasted interest rates for both energy and water utilities. Recently, the Commission has relied upon DRI forecasts to make those determinations. Dr. Woolridge provides no evidence (other than his opinion) that this Commission policy should be changed.

Third, part of the reason Dr. Woolridge offers for his opinion that forecasted interest rates should not be relied upon is he is not aware of any studies that indicate they should be. There is such a study. The Arizona Corporation Commission ("ACC") Staff prepared an analysis in 2003 that showed interest rate forecasts are not biased. At page 49 of the ACC Staff direct testimony in Docket No. WS-01303A-02-0867, Staff witness Joel Reiker presented Chart 4 that compared *Blue Chip Financial Forecasts*[2] consensus forecasts of Aaa corporate bond rates to actual rates for the period 1999 to 2003. The data underlying the chart are provided below:

Year	Blue Chip Projected Rate	Actual Rate	Difference
1999	6.90%	7.05%	-0.15%
2000	6.80%	7.62%	-0.82%
2001	6.60%	7.08%	-0.48%
2002	6.60%	6.49%	0.11%
2003	6.60%	5.94%	0.66%

These data show that in three years, the projected *Blue Chip* interest rates were lower than actual rates and in the other two years, projected rates were higher than subsequently occurred. On average, the *Blue Chip* projections of future rates were slightly below the rates that actually occurred. This evidence provides strong support for the consensus forecasts being unbiased, and certainly not working against the interests of ratepayers. It has been my experience that Blue Chip forecasts are generally in line with DRI forecasts the Commission has primarily relied upon in recent GRCs.

Interest rates that should be relied upon to determine San Gabriel's costs of debt and equity should be the best available forecasts of interest rates expected during 2006, 2007, 2008, and 2009, the years in which new tariffs will be in effect. Relying on "actual" market interest rates in 2005 does not solve the problem of uncertainty about what the interest rates will be in the 2006-2009 period, when new rates will be put in place. Also, in a period in which it is generally acknowledged that interest rates are expected to increase, reliance on interest rates that exist *prior* to the time new rates will be put into place is clearly going to bias

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2 The CPUC generally relies upon interest rate forecasts made by DRI. In the past, however, the CPUC has relied upon consensus interest rate forecasts reported by Blue Chip and DRI in GRCs in which I participated.

downward debt cost and equity cost estimates. With interest rates currently low, compared with interest rates over the past several decades, the chance future rates will be higher than rates today is much better than the chance they will be lower. As a result, the CPUC policy of relying on forecasted rates should continue to be adopted in this case and San Gabriel's projected costs of debt and equity should be based on those forecasts.

Q. DR. WOOLRIDGE DISCUSSES BETA ESTIMATES AS A MEASURE OF RISK. DO YOU HAVE ANY COMMENTS ABOUT BETAS FOR WATER UTILITIES?

A. Yes, I have three comments.

First, at page 15, Dr. Woolridge says "according to modern capital market theory [beta] is the only relevant measure of investment risk that need be of concern for investors". He then goes on to note that a study conducted by Damodoram from New York University shows the beta estimates reported by the *Value Line Investment Survey* indicate water utilities have investment risk that puts them in the bottom tenth of the 100 industries studied. While I do not agree that beta is the *only relevant* measure of risk, I do respond to Dr. Woolridge's suggestion that the true betas (not estimates of betas) for water utilities are as low as Damodoram reports. Many water utilities are small and infrequently traded and thus, when short interval periods of data (such as weekly data used by Value Line) are used to estimate betas, Professor Roll has shown such beta estimates will be biased downward. (See Attachment 2 to my direct testimony). I do not know and Dr. Woolridge does not tell us the names of the 17 companies Damodoram has classified as "water utilities." AUS Utility Reports follows only 10 water utilities. *Value Line* reports data for only 8 water utilities in its Standard and Expanded Editions of *The Value Line Investment Survey.* Obviously, Damodoram has included 9 other companies *Value Line* does not report as water utilities in these published paper Editions of *The Value Line Investment Survey.* I expect the other companies in Damodoram's sample—if they are water utilities–are very small and not frequently traded. As a result, based on the theoretical work of Roll, the estimated betas for the sample of 17 "water utilities" are expected to be biased downward.

Second, Panel A of Rebuttal Table 9 reports beta estimates relied upon by Dr. Woolridge and Mr. Cuthbert, as well as betas reported by Reuters for the ORA Staff water utilities sample. The average of betas for this sample of 6 utilities is now .96—very close to a beta of 1.0, the beta of an average risk company. At page 32, Dr. Woolridge mentions that *Reuters* and *Yahoo* are investment services that provide beta estimates and thus I have included them in this table. Mr. Cuthbert reports betas from Thomson, which I assume are the Yahoo betas. For perspective, in past cases, ORA Staff has relied upon estimates of betas reported by *Value Line* and *Reuters* (formerly Multex). An average of the betas reported by just those two services is 1.02—slightly above the average risk company beta. A sample with a beta that is virtually equal to 1.0 is an average risk industry, not an industry in the lowest percentile of risky companies.

Panel B of Rebuttal Table 9 may explain part of the difference in beta estimates. Damodoram reports an average *Value Line* beta for his 17 companies (whoever they are) of .60. In 2001, the average *Value Line* beta for the three largest water utilities was also .60. That average *Value Line* beta has increased by 28% to .77 in 2005. Possibly the study by Damodoram that Dr. Woolridge has chosen to provide is simply out of date and fails to recognize the significant increase in beta risk which has occurred in the water utilities industry in the last five years.

Third, Dr. Woolridge relies upon the CAPM to make one of his equity cost estimates. These average beta estimates of .74 or .96 would increase his CAPM estimate of the cost of equity.

Q. PLEASE TURN TO YOUR COMMENTS ABOUT DR. WOOLRIDGE'S DCF ANALYSIS. BEGIN WITH A DISCUSSION OF HIS SAMPLES OF WATER UTILITIES.

A. Dr. Woolridge bases his analyses on data for ten water utilities followed by AUS Utility Reports. He includes Artesian Resources, Pennichuck Corp, Southwest Water, and York Water in his samples, in addition to the six water utilities normally relied upon by ORA Staff to make their equity cost estimates. ORA Staff and I would not include SW Water in a sample used to determine equity costs for water utilities because SW Water has only 38 percent of its revenues from regulated water operations[3]. I would not include Pennichuck Corp in the sample because of the limited information for the Company. There are no analysts' forecasts of growth for Pennichuck and data available to investors are limited because data for the company are not published by *Value Line*.

Q. WOULD INCLUSION OF ARTESIAN RESOURCES AND YORK WATER IN THE SAMPLE OF SIX WATER UTILITIES REDUCE YOUR DCF EQUITY COST ESTIMATES?

A. No. If the ORA sample of six water utilities were increased to include Artesian Resources and York Water, the DCF approach I use would still support an ROE for San Gabriel that is higher than the 11.5% ROE requested by the Company. Panel A of Rebuttal Table 10 shows average dividend yields for 3-month, 6-month and 12 month periods computed with the same method used by ORA Staff to recognize the time value of money. Panel B of the table reports analysts' forecasts of growth reported by four investor service for those two water utilities. There are no forward-looking data to estimate BR+VS growth I present in my direct testimony. In Panel C, I used the same methods used by ORA Staff to compute DCF equity cost estimates but limited my analysis to the forward-looking estimates of growth shown in Panel B. Based on that analysis, the indicated DCF cost of equity for this sample of two water utilities falls in a range of 10.9% to 11.2% and the indicated cost of equity for San Gabriel is 12.1% to 12.4%. Including these two utilities in my analysis would increase the estimated DCF cost of equity.

Q. DO YOU AGREE WITH THE METHOD DR. WOOLRIDGE HAS USED TO COMPUTE THE CURRENT DIVIDEND YIELD?

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[3] In past cases, ORA Staff has said it will not include a company in the water utilities sample unless it has at least 70% of its revenues from water and wastewater utility operations.

A. No. In equation (1) on page 29 of my direct testimony, I define the current dividend yield as D_0/P_0. Dr. Woolridge relies upon a simple average of dividend yields reported by AUS Utility Reports (formerly C. A. Turner Utility Reports) for a six month period and the most recent month. He has not, however increased those dividend yields to recognize the time value of money. A simple example will show why the time value of money must be recognized. Consider two different ways a utility pays a dividend of $100:

	March	June	September	December
Method 1	$25	$25	$25	$25
Method 2				$100

Obviously an investor would prefer to receive his $100 dividend sooner by getting paid four quarterly payments of $25 instead of waiting until the end of the year to get a single $100 payment. He/she would pay more for a stock that pays $25 per quarter than a stock that pays just one dividend at the end of each year. The DCF model Dr. Woolridge and I use assumes the full dividend is paid just once a year (i.e., D_0 in the current year, and D_1 at the end of the first year, D_2 at the end of the second year, and so on) when those dividends are actually paid sooner in quarterly payments. To make the price paid (P_0) and the dividends paid internally consistent, the time value of money of getting each of the dividend payments sooner than at the end of each year must be recognized. ORA Staff and I have made such an adjustment but Dr. Woolridge and Mr. Cuthbert have not. This is one of the ways Dr. Woolridge and Mr. Cuthbert bias downward their equity cost estimates.

Q. DR. WOOLRIDGE CRITICIZES YOUR RECOGNITION OF THE TIME VALUE OF MONEY WHEN YOU COMPUTE DIVIDEND YIELDS. AT PAGE 62, HE OFFERS A QUOTATION FROM A JOURNAL ARTICLE TO SUPPORT HIS CONTENTION. DOES IT PROVIDE SUCH SUPPORT?

A. No, it does not. As shown in the example above, clearly investors would prefer to receive dividends sooner rather than later and the estimates of dividend yields should reflect that preference. In past rate cases, ORA Staff has agreed with me.

Q. DO YOU AGREE WITH THE METHOD DR. WOOLRIDGE AND MR. CUTHBERT HAVE USED TO COMPUTE D_1/P_0, THE DIVIDEND YIELD IN DR. WOOLRIDGE'S EQUATION AT THE TOP OF PAGE 20 AND THE FORMULA ON PAGE 15 OF MR. CUTHBERT'S TESTIMONY?

A. No. ORA Staff, Dr. Woolridge, Mr. Cuthbert and I use the constant growth DCF model. The valuation model ORA Staff and I rely upon assumes there is indeed constant growth in every year. Growth in the first year is the same as it is in the second year, third year and so on. Dr. Woolridge and Mr. Cuthbert do not. While they assume growth in the second year is the same as it is in the third year and other future years, their models assume investors expect only one-half that amount of growth in the first year. Mr. Cuthbert does not explain why he uses only one-half of the growth rate to determine D_1/P_0. At page 22, Dr. Woolridge says he made this choice based on a consideration of the rate base being used in a rate-making process when there are future test years. If indeed that is why Dr. Woolridge modified the constant growth DCF model used by ORA Staff in so many cases in the past, Dr. Woolridge's method should be clearly rejected. The ROE witness should not be adjusting downward his ROE to offset policies the Commission has determined should be followed in determining rate base in future test years. ORA Staff and I have correctly increased the current dividend by the full growth rate. Dr. Woolridge's approach and Mr. Cuthbert's approach which allow for only one-half the level constant growth in the first year should be rejected. This choice is clearly designed for one purpose, to push down the DCF cost of equity estimates.

Q. DO YOU HAVE ANY COMMENTS ABOUT THE GROWTH RATES DR. WOOLRIDGE USES IN HIS VERSION OF THE DCF MODEL?

A. Yes. Dr. Woolridge employs a number of flawed concepts that reduce his DCF growth rate estimates. The first flawed concept is reliance on geometric rather than conceptually correct arithmetic growth rates. At page 24-25, he states that he relies in part on the compound annual historic growth rates he reports on page 3 of Exhibit_JRW-7). It is, of course, appropriate to describe past growth with geometric annual average estimates of growth, but even if one believes that future growth for water utilities will be similar to growth in the past—an assumption the data I present in Table 6 of my direct testimony show cannot be supported—it is conceptually incorrect to use such past geometric average growth rates to determine growth in the future. With this issue and with respect to his determination of risk premiums later in his testimony, Dr. Woolridge relies upon geometric averages instead of the conceptually correct arithmetic averages. In all of the CPUC Staff testimony in water utility cases I have reviewed over the years, until this case, I have never seen a Staff witness propose the adoption of this conceptually incorrect concept to determine equity costs.

Q. WHAT IS THE RELATIONSHIP BETWEEN ARITHMETIC AVERAGE RETURNS AND GEOMETRIC AVERAGE RETURNS?

A. The relationship between arithmetic average returns (A) and geometric average returns (G) has been shown to be

$$A^2 \approx G^2 + \mathrm{Var}(A),$$

where the square of the arithmetic returns (A^2) is approximately equal to the square of the geometric average return (G^2) plus the variance in the arithmetic returns (Var(A)). If the return or growth rate is exactly the same in every period, the Var(A) would be zero and the two returns would be the same. Generally this is not the case. Thus, if one believes future growth (or future returns) and variance in future growth (returns) will be similar to what has occurred in the past, the arithmetic average growth rate must be used to determine equity costs or the utility will be unable to achieve the past geometric growth (or the past geometric returns). Dr. Woolridge's proposal to consider past geometric average growth (compound growth) and later to consider past geometric averages of returns is a results-driven way to make sure a utility will not attain the forecasted growth or earn returns in the future that have occurred in the past.

Q. FOR THE MOMENT, PLEASE SKIP AHEAD TO PAGE 77 WHERE DR. WOOLRIDGE PROVIDES AN EXAMPLE HE CLAIMS SHOWS THERE IS A PROBLEM WITH USING ARITHMETIC RETURNS. PLEASE RESPOND TO THAT TESTIMONY.

A. I have included Rebuttal Table 11 and Attachments _(TMZ-1) and _(TMZ-2) to respond to his testimony. While the testimony he presents at page 77 refers to arithmetic and geometric returns the same issue is present when computing growth rates. Attachment_(TMZ-1) is a section out of a widely accepted finance textbook by Brealey and Myers. Brealey and Myers provide an excellent example showing that with a possibility of annual returns of -10%, +10% and +30%, the expected return is 10% (an average of the three returns) and with an initial investment of $100 in that stock, the expected end-of period value of the stock is $110 (if no dividend is paid). They show that this 10% return must be the discount rate used to determine the present value of the stock of $100. They also show that the compound average return of 8.8% (which would produce an end-of-period value of $108.80 is less than the opportunity cost of capital. Thus, if this were a utility stock and a regulator set the return at only 8.8%, investors would not be willing to invest in that utility stock because the opportunity cost of investing elsewhere is 10%. This same example applies to the determination of forward-looking growth rates from historical data. Attachment_(TMZ-2) is another way of looking at the same issue. It is presented in Ibbotson Associates 2005 SBBI Valuation Edition. Using this alternative explanation, Ibbotson also show the appropriate average to use in determining required future returns (growth rates) is the arithmetic average and not the geometric average.

Q. AT PAGE 77, DR. WOOLRIDGE PROVIDES AND EXAMPLE HE CLAIMS PROVIDES SUPPORT FOR RELIANCE ON GEOMETIRC RETURNS. DO YOU HAVE A RESPONSE?

A. Yes, Rebuttal Table 11 provides that response. It takes the concepts presented in Attachment_(TMZ-1) and Attachment_(TMZ-2), and applies them to the specific example Dr. Woolridge presents. It assumes that investors recognize all of the potential investment outcomes suggested by Dr. Woolridge's example. Rebuttal Table 11 also shows the situation when there is no expected variance in returns (say with a Treasury security). In that situation, the arithmetic and geometric average returns would be the same. Dr. Woolridge's example is clearly not such a situation and thus the arithmetic average return is the return required by investors. The real problem with Dr. Woolridge's example is that it assumes investors already know what will happen in the future when they do not. In effect, his example assumes investors will know the final outcome when that is never the case with investments in common stocks. If an investor actually expected he/she would only get back the $100 he/she originally invested, the investor would be better off putting the $100 under a mattress and taking it out at the end of the two years. Without compensation for the time value of money and the risk of getting the $100 back, a knowledgeable investor would not make the investment.

Q. AT PAGE 26, DR. WOOLRIDGE SUMMARIZES THE GROWTH RATES HE RELIES UPON. DO YOU HAVE ANY COMMENTS ABOUT THIS TESTIMONY?

A. Yes. I have fully discussed this issue in my direct testimony and will not repeat all of my comments. I will however, point out the article I discuss in my direct testimony by Gordon, Gordon and Gould ("GG&G") that found analysts' forecasts of growth were superior to measures of growth similar to the ones Dr. Woolridge relies upon in his table at page 27. Studies by Brown and Rozeff (1978), Cragg and Malkiel (1982), VanderWeide and Carleton (1988) and Timme and Eizeman (1989) also found that analysts' forecasts of growth provide superior measures of future growth (as reported by Roger A. Morin, *Regulatory Finance: Utilities' Cost of Capital*, Public Utilities Reports 1994, pp. 154-155). Reliance on measures of past growth will double-count such growth because analysts would have already taken it into account when they made their forecasts. The averages of analysts' forecasts of growth reported by Dr. Woolridge for his large water utilities sample of 6.6% is biased downward by Dr. Woolridge excluding Value Line from the average. Dr. Woolridge reports separately the estimates of future EPS growth made by *Value Line*. If, however, data for *Value Line* are included in the average, the forecasted growth rate for the LWC sample increases from 6.6% to 7.8%. The 7.8% growth rate is comparable to the 8.27% growth rate Staff computed in A.05-08-034. The 8.37% differs from the 7.8% because Dr. Woolridge and ORA Staff relied on different samples and used data obtained on different dates. Both ORA Staff (in

A.05-08-034) and I include *Value Line* estimates of future EPS growth in our averages of analysts' forecasts of growth.

I also do not agree with his decision to base a projection of Value Line growth rates for his LWC sample on an average that includes forecasted DPS growth. At page 18-19, Dr. Woolridge acknowledges that forecasted near-term DPS growth understates the long term growth he says should be used in the DCF analysis. If projected DPS growth is excluded from his average of *Value Line* projections, the projected Value Line average growth rate he reports at page 27 for the LWC sample increases from 7.7% to 9.0%.

The table below shows DCF estimates based on forward-looking estimates of growth for the six water utilities in the ORA Staff sample that were determined by Dr. Woolridge with two changes I have explained above. Estimates of dividend yields used in the DCF model (D_1/P_0) are determined by increasing his estimates of the current dividend yields by the full growth rate used in the analysis, not half of the growth rate. The other change I have made is based on my restatement of his DCF equity cost estimates on conceptually correct estimates of growth he determined. To be conservative, I have not adjusted his current dividend yields for the time value of money. Based on ORA Staff's recent report in A.05-08-034 (see Rebuttal Table 1), using Dr. Woolridge's current dividend yields understates the cost of equity by about 20 basis points. His restated DCF equity cost estimates are as follows:

Source of Growth Rate	Current Yield	D_1/P_0 Adjustment	DCF Growth	Equity Cost
Ex. JRW 7.4	2.9%	1.073	7.3%	10.4%
Ex. JRW 7.5	2.9%	1.08	8.0%	11.1%

I report alternative estimates of growth for the ORA sample that are based on two different ways of incorporating Value Line's estimate of future EPS growth.

Q. PLEASE TURN TO DR. WOOLRIDGE'S CRITIQUE OF YOUR TESTIMONY. DOES HE AGREE THAT ESTIMATES OF GROWTH USED IN THE DCF ANALYSIS SHOULD BE LIMITED TO FORWARD-LOOKING ESTIMATES OF GROWTH?

A. No, he does not. I have based my equity cost estimates—as does the Federal Energy Regulatory Commission—on two measures of forward-looking growth. One is sustainable (br+sv) growth. The other is an average of analysts' forecasts of growth.

At page 63, Dr. Woolridge criticizes my estimates of sustainable growth based on Value Line forecasts of retention ratios (b), future ROEs (r), future issues of shares of stock (s) and current market-to-book ratios (used to determine v) by comparing those forecasts to Value Line forecasts of book value growth. It is true that in equilibrium, growth in stock prices, book values, EPS and DPS will all be the same. But since *Value Line*'s forecasts of those variables are not the same at this time, forecasts of book value growth will not necessarily equal forecasted br+sv growth. The data Dr. Woolridge reports for book value growth is consistent with my observation. His data show that in one case forecasted book value growth exceeds br+sv growth and in the two other cases book value growth estimates are below my estimates of sustainable growth. In addition, I adjust my estimates of BR growth using the formula used by FERC to recognize *Value Line* reports ROEs on an end of year basis. Contrary to Dr. Woolridge's claim, his reported book value growth rates do not show there is any bias in my estimates of sustainable growth and his critique should be ignored.

Q. WHAT IS DR. WOOLRIDGE'S OTHER CHALLENGE OF YOUR GROWTH RATE ESTIMATES?

A. Dr. Woolridge's other challenge is that analysts' estimates of EPS growth are upwardly biased. He offers testimony from page 64 to 68 to support his contention. He also offers testimony at page 82 that also alleges analysts (in this case *Value Line*) make overly optimistic forecasts of future ROEs.

Q. WHAT IS YOUR RESPONSE TO HIS TESTIMONY?

A. My initial response is shown in Attachment_(TMZ-3). It reports that–contrary to Dr. Woolridge's claim–analysts' forecasts of EPS growth have recently been less than what has actually occurred. In an article posted 4/23/2004, *USA Today* stated more than half of the S&P500 companies had reported earnings at that point in time and 78% of those companies beat analysts' estimates. The article also pointed out that *typically*, only 58% of companies beat forecasts. If more than half of the companies typically beat earnings forecasts, the optimistic bias—at least in short-term forecasts—suggested by Dr. Woolridge does not exist.

Q. AT PAGE 82, DR. WOOLRIDGE CRITICIZES ANALYSTS' FORECASTS OF FUTURE ROES THAT YOU REPORT IN YOUR TABLE 17. DO YOU HAVE A RESPONSE?

A. Yes. I have two responses. First, yet again, Dr. Woolridge erroneously reports a geometric average return of 10.4% to criticize my forward-looking estimate of future returns of 14.63%. If he wanted to put my number in perspective he should have compared the forecast I report in Table 17 with the long term average arithmetic return of 12.4% for large company stocks. I agree with Dr. Woolridge that the estimate of future market returns presented in Table 17 produces a forward-looking estimate of market returns that is higher than 12.4%, but that was the point of Table 17. Table 17 shows that contrary to the many studies he presents, there is market evidence that investors can reasonably expect higher returns in the future than have been earned in the past.

Second, the study he presents at page 2 of Exhibit_(JRW-10) is flawed. He claims his study supports a conclusion that *Value Line*'s projected 3-5 year returns have been, on average, 3.24% higher than actual returns. His study provides no such evidence. It compares apples (median forecasts of returns for 1700 stocks) with oranges (actual S&P500 index returns). The S&P500 index is based on a weighted average of the 500 stock returns whereas the Value Line forecasts are for median expected returns for 1700 individual stocks. I do not have a complete collection of old Value Line Section & Opinion reports that provide estimates of Value Line index returns that occurred during the period of Dr. Woolridge's study. I did find one dated December 24, 2004 that reports the following annual returns for the prior 12 months (see Attachment_TMZ-4):

S&P 500 Index	11.9%
Value Line (Geometric Index)	13.9%
Value Line (Arithmetic Index)	19.8%

The *Value Line* 1700 stocks are used to construct both of the Value Line Indices. In other periods, the difference between *S&P500* index returns and returns for the *Value Line* indices might be smaller or larger, but Dr. Woolridge offers no evidence to conclude the returns for these indices would ever be the same.

There is, also, a second problem with Dr. Woolridge's study that creates a clear bias. During the period in which the forecasts are compared to actual returns, on average, actual inflation turned out to be 1.22% less than was expected when the Value Line's forecasts of ROEs were made. See Rebuttal Table 12. *Value Line* correlates its forecasts of EPS and ROEs with estimates of inflation that will undoubtedly turn out to be higher or lower than they predict. A proper evaluation of the quality of *Value Line* forecasts should remove this measurable difference in predicted and realized inflation and consider how well *Value Line's* forecasts performed in real terms. Based on such a consideration of real forecasts, Dr. Woolridge's 3.24% difference in returns for the two indices becomes 2.02% (3.24 - 1.22).

Q. HAVE YOU EVER CONDUCTED A TEST OF THE QUALITY OF *VALUE LINE* FORECASTS IN WHICH YOU COMPARED APPLES TO APPLES?

A. Yes, I have. In contrast to Dr. Woolridge's study which compared apples to oranges, my study compared *Value Line* forecasts of returns for a sample of 8 gas distribution utilities (apples) to realized returns for the same sample of 8 gas distribution utilities (apples) during the 21 year period 1977 to 1998. In my study, I also took into account differences in forecasted and realized rates of inflation and thus compared real forecasts of returns with realized real returns. I have attached the results of my study as Rebuttal Table 13. This study shows that after recognizing differences in actual and realized inflation the average of *Value Line* forecasts of ROEs were 11 basis points lower than subsequently occurred. *Value Line* should be patted on the back for making such reliable and accurate forecasts, not disparaged.

Q. IS THIS STUDY IMPORTANT TO AN EVALUATION OF DR. WOOLRIDGE'S CONTENTION THAT ANALYSTS' FORECASTS ARE TYPICALLY TOO OPTIMISTIC?

A. Yes, it is. My study shows that, at least for utilities, the *Value Line* forecasts were not biased upward during a 21 year period.

Q. AT PAGE 64-67, DR. WOOLRIDGE OFFERS TWO STUDIES OF ANALYSTS' FORECASTS OF EPS GROWTH AS A BASIS TO CHALLENGE THE USEFULNESS OF SUCH FORECASTS. DO YOU HAVE ANY CONCERNS WITH THE DATA USED IN HIS REPORTS?

A. Yes. First, Dr. Woolridge has not provided a study of the accuracy of analysts' forecasts of growth for utilities.

Second, apparently his forecasted and realized earnings numbers are for an equally weighted average of EPS data, not value-weighted data. This makes it difficult to compare his analysis with numbers generally reported for the value-weighted S&P500 index. Based on my past experience, equally weighted returns for a stock index will be greater than value-weighted returns.

Q. DO YOU HAVE ANY OTHER RESPONSES TO DR. WOOLRIDGE'S CONTENTION THAT ANALYSTS OVERESTIMATE LONG-TERM ESTIMATES OF EPS GROWTH?

A. Yes, I have three other comments. First, I refer the reader back to my direct testimony at page 31. GG&G conducted a study and found analysts' forecasts of growth outperformed three measures of growth based on recorded data. GG&G go on to explain that such a result is logical because analysts would review past data in forming their projections for the future. Dr. Woolridge offers no quantitative or conceptual argument to rebut GG&G and offers no evidence that any of the various measures of past growth (past sales growth, past EPS growth, past DPS growth, past book value growth, past internal growth) listed in his table at the top of page 27 of his testimony provide better forecasts than analysts' estimates of future growth. Dr. Woolridge would just have the Commission "throw the baby out with the bath water" so that he can create negatively biased estimates of equity costs.

Second, I agree that it is generally acknowledged that there are upward biases in Wall Street estimates of "buy," "hold," and "sell" recommendations when firms would make commissions from selling stocks to clients. This is a totally separate issue from bias in earnings growth estimates and should not be confused.

Third, Value *Line* is in the business of selling information to investors. It has the incentive to provide accurate—not upwardly biased–forecasts so that investors will continue to buy subscriptions. Attachment_(TMZ-5) is an open letter from *Value Line's* Chairman and CEO to its subscribers describing its goal to provide "the most accurate information and independent advice anywhere." *Value Line* does not sell stock and thus does not have the incentive to bias upward buy/sell recommendations or bias upward its estimates of future growth that is often attributed to Wall Street analysts who work for firms that do sell stock to the public. For perspective, these unbiased *Value Line* forecasts Dr. Woolridge, Mr. Cuthbert and I report in our studies are all the same or higher than the average of analysts' forecasts of growth reported *by Zacks, Thomson First Call, Reuters, and the S&P Earnings Guide*. Dr. Woolridge's attempt to challenge the usefulness of analysts' forecasts of growth should be given no weight and the restatement of his DCF analysis I provided above is reasonable.

Q. PLEASE TURN TO YOUR COMMENTS ABOUT DR. WOOLRIDGE'S RISK PREMIUM ANALYSES.

A. Dr. Woolridge presents only one risk premium analysis. It is based on his version of the CAPM.

Q. ARE THERE ANY FUNDAMENTAL PROBLEMS WITH RELYING ON ONLY THE CAPM TO MAKE RISK PREMIUM ESTIMATES OF THE COST OF EQUITY?

A. Yes. Each of the RP approaches I presented in my direct testimony is transparent. It is easy to see what I did and what I have assumed. Generally, my risk premium analyses assume the relationships between equity and bond returns that existed in the past will continue into the future.

It is not so easy to penetrate the data being used in the CAPM. To make a CAPM estimate one needs to first determine what model will be used (there are a lot of variations of the CAPM), what return should be assumed for the zero beta asset, what is the beta risk (and possible other systematic risks) of the asset at issue and what is the market risk premium (and if other systematic risks are recognized what premiums are required for them). In my direct testimony I present what I have called the traditional CAPM which has occasionally been presented by the CPUC Staff in water utility rate cases. In most cases, CPUC Staff has relied upon a straight-forward version of the RP model.

Q. SHOULD RISK PREMIUM ANALYSES BE LIMITED TO THE CAPM?

A. No. While I agree it is not unreasonable to consider a CAPM estimate, it should not be given a large weight. At page 35 of his testimony, Dr. Woolridge notes that Professors Fama and French are "preeminent scholars in finance". In 2004, Fama and French presented a survey article titled "The Capital Asset Pricing Model: Theory and Evidence" which was published in the prestigious *Journal of Economic Perspectives*, Vol. 18, No. 3, Summer 2004, pages 25-46. In the summary of that article, Fama and French say the following:

> "The CAPM, like Markowitz's portfolio model on which it is built, is nevertheless a theoretical tour de force. We continue to teach the CAPM as an introduction to the fundamental concepts of portfolio theory and asset pricing, to be built on by more complicated models like Merton's ICAPM. But, we also warn students that despite its seductive simplicity, ***the CAPM's empirical problems probably invalidate its use in applications.***" (page 44.) (Emphasis added.)

One of the empirical problems Fama and French point out is that equity cost estimates for low beta stocks are too low (Ibid).

Q. DO YOU HAVE CONCERNS WITH THE INPUTS DR. WOOLRIDGE USES TO IMPLEMENT THE CAPM?

A. Yes. Dr. Woolridge presents the CAPM equation at page 28. His choice of inputs for the zero-beta asset (R_f), the beta and the expected market risk premium (MRP) all bias downward the cost of equity estimate he makes. Dr. Woolridge's poor choices of inputs together with the warning Fama and French give their students indicate little if any weight should be given to Dr. Woolridge's attempt to implement the CAPM.

Q. WHAT IS THE PRIMARY PROBLEM WITH HIS ESTIMATE OF R_F?

A. The primary problem is that Dr. Woolridge's estimate of 4.75% for R_f is much lower than is being forecasted for the period in which new rates will be put in place for San Gabriel. Updated data for the interest rate forecasts relied upon by ORA Staff in the SWS case indicate the appropriate value for R_f is 5.61%, a value 86 basis points higher. To be consistent with past Commission practice and the best available forecast of interest rates for the period new rates will be in effect, the value of 5.61% should be adopted for R_f.

Q. DO YOU HAVE ANY CONCERNS WITH HIS ESTIMATES OF BETAS?

A. Yes. I addressed this issue above. Dr. Woolridge mentions three potential sources of beta estimates at page 32. An average of the betas reported by those three investor information service providers is .96 for the ORA Staff sample. Even if only *Value Line* betas were used in his analysis, the average beta for the ORA Staff water utilities sample would increase to .74. As I explain above, academic studies show beta estimates for smaller water utilities are expected to be biased downward because those firms are not frequently traded; therefore, those estimates should not be included when determining an estimate of beta for a water utilities sample.

Q. DO YOU HAVE ANY COMMENTS ABOUT DR. WOOLRIDGE'S MARKET RISK PREMIUM ESTIMATES?

A. Yes. First, at page 33, Dr. Woolridge claims the traditional method of estimating the market risk premium is called the "Ibbotson approach" and states it is based on the average difference between stock and bond returns. But, at page 3 of 5 of Exhibit_(JRW-8) he reports that a risk premium based on this "traditional method" and data from Ibbotson Associates produces a long-term average arithmetic market risk premium estimate is 6.6%, when that is not the case. The actual long-horizon average market risk premium computed by Ibbotson Associates is 7.2%. This value is reported by Ibbotson Associates in its "Table 5-1 Equity Risk Premium with Different Market Indices" and also on the back page containing "Key Variables in Estimating the Cost of Capital" of the *2005 SBBI Valuation Edition*. It is also found in "Table 9-1: "Building Blocks for Expected Return Construction" reported in the *2005 SBBI Yearbook*. Dr. Woolridge does not explain why he has ignored

Ibbotson's actual calculation of the long-horizon market risk premium. At line 17 of page 33 he suggests historic average estimates of market risk premiums are in the 5% to 7% range when even the Ibbotson Associates estimate is above that range.

Q. DO YOU HAVE ANY COMMENTS ABOUT THE NEW ACADEMIC STUDIES OF MARKET RISK PREMIUMS HE PRESENTS AT PAGES 35 TO 47?

A. No. I doubt that investors are familiar with any of those studies. Additionally, I presented evidence in Table 17 of my direct testimony that shows *Value Line*—a source available to virtually all investors—estimates of forward-looking equity costs indicate investors could expect higher not lower market risk premiums in the future. The important issue here is what investors think the market risk premium will be. Investors have access to *Value Line* data and that data indicates future market risk premiums may be higher than the long-horizon average market risk premium of 7.2% estimated by Ibbotson Associates.

Q. HAVE YOU DETERMINED A CAPM ESTIMATE THAT IS MORE APPROPRIATE THAN THE ONE PRESENTED BY DR. WOOLRIDGE?

A. Yes. That estimate is based on the current forecast of R_f for the period new rates will be in effect for San Gabriel, the updated Value Line beta of .74 and the long-term average market risk premium of 7.2%.

	R_f	beta	MRP	Equity Cost
Equity cost =	5.43%	.74	7.2%	10.8%

If the estimate were instead based on an average of betas reported by *Value Line*, Thomson and Reuters of .96, the CAPM estimate would be

Equity Cost =	5.43%	.96	7.2%	12.3%

To estimate a cost of equity for San Gabriel I would add a risk premium to recognize San Gabriel is more risky than the ORA sample. As stated above, however, given the problems with applying the CAPM in real situations, it is my opinion that more weight should be given to RP approaches other than CAPM.

Q. AT PAGES 70-83, DR. WOOLRIDGE CRITICIZES YOUR RISK PREMIUM APPROACHES. DO YOU HAVE A RESPONSE?

A. Yes. At pages 70-71, he criticizes my use of forecasted interest rates in these models. I have responded to his position above. It is Commission policy to use forecasted interest rates. That policy should not be changed. Forecasted rates are not expected to be biased and are for the period new rates will be in effect.

At pages 71-74, he criticizes me for not performing an "analysis" to examine if annual earned or authorized ROEs are good indicators of investors' required returns (p. 72, lines 12-14). Dr. Woolridge misses the entire point of my studies. As I have previously explained, both realized ROEs and authorized ROEs reveal indications of what commissions have determined are market costs of equity in past cases. These returns also reflect opportunity costs for investors which the U. S. Supreme Court has found must be considered when setting ROEs for utilities.

Q. DOES DR. WOOLRIDGE ACKNOWLEDGE THAT SAN GABRIEL REQUIRES AN EQUITY RISK PREMIUM?

A. Yes. At page 48 of his testimony, he says "given San Gabriel's size, an equity cost rate in the upper end of the range is appropriate." At page 53-57, however, he does not agree with me that the risk premium should be as large as 120 basis points. He is unwilling to acknowledge that California has a more risky regulatory environment than other states, that the Commission has recognized San Gabriel has more risk related to its sources of water, that D. 03-06-072 has increased risk, and that San Gabriel has greater exposure to risks of recovery of litigation expenses. I am optimistic that the proposed Water Action Plan will reduce some of those risks, but for now, I take the wait-and-see attitude that *Value Line* took on November 11, 2005 when it said "we want to see the outcome of some rate cases in California before we raise the [ranking of regulatory] climate to Average" [from below Average] (*Value Line Investment Survey*, Issue 11, page 1776, dated November 11, 2005)}.

At page 57, Dr. Woolridge questions the usefulness of the quantitative evidence I presented that supported San Gabriel being more risky, but presents no quantitative evidence of his own to show I erred. Ultimately, at page 48, Dr. Woolridge agrees that at least with respect to size, San Gabriel is more risky.

In San Gabriel's most recent order, the Commission found San Gabriel should be provided a premium above ORA Staff's estimate of the cost of equity of 70 basis points. In the current case, the 70 basis point premium above ORA Staff's most recent determination of the cost of equity for its sample, once corrected to be consistent with past ORA Staff presentations, would indicate an equity cost for San Gabriel of 10.6% (9.9% plus 70 basis points) is appropriate at this time.

Q. AT PAGE 49 TO 50 DR. WOOLRIDGE CLAIMS THAT A CONSIDERATION OF MARKET-TO-BOOK RATIOS JUSTIFIES REDUCING SAN GABRIEL'S AUTHORIZED ROE BELOW 10.10%. DO YOU HAVE A RESPONSE?

A. Yes. In my direct testimony, I listed a number of reasons market-to-book ratios are expected to be above 1.0 even if water utilities are making less than authorized ROEs. (For the last ten years, on average, water utilities in ORA's sample have made less than their authorized ROEs). Risk, as measured by betas, has increased for water utilities over the last 5 years by 28%. If indeed beta provides a relevant measure of risk—as Dr. Woolridge claims it does—authorized ROEs should be increased to compensate for this higher risk. A consideration of market-to-book ratios doesn't provide such a reasonableness check.

Q. AT PAGE 50, DR. WOOLRIDGE BEGINS HIS SPECIFIC CRITICISMS OF YOUR EQUITY COST ESTIMATES. YOU HAVE ALREADY RESPONDED TO A NUMBER OF THE POINTS HE PRESENTED. DO YOU HAVE ANY OTHER RESPONSES?

A. Yes, I note the following points not already addressed:

1. At pages 57-58, he takes issue with the capital structure San Gabriel proposed. He does, however, agree that the equity ratio of 60% previously adopted by this Commission for San Gabriel should be used for rate-making purposes.

2. At pages 58-59, he expresses his opinion that forecasted interest rates should not be used to determine debt costs. Above I have explained why forecasted interest rates are preferred and are consistent with past Commission practice. San Gabriel's proposed future debt costs are appropriate and should be adopted. They are the best available forecasts of test year interest rates and consistent with past Commission practice.

3. At pages 72-74 and other places, Dr. Woolridge suggests that current market-to-book ratios for water utilities indicate they are earning more than their costs of equity. In my direct testimony, I have offered several reasons to expect water utilities to have market-to-book ratios above 1.0 even if they are making less than their authorized ROEs. But market-to-book ratios provide no check on the reasonableness of ROEs. Ultimately, the test set out by the U.S. Supreme Court is whether the return that is being authorized is no less than the opportunity cost (returns that could be earned by investing in other companies of similar risk). I am not a lawyer, but based on my understanding of the *Hope* and *Bluefield* decisions of the U. S. Supreme Court, Dr. Woolridge's position regarding market-to-book ratios is inconsistent with mandates of the U.S. Supreme Court as to what is a fair return.

4. At pages 74-83, he discusses several alleged problems with my risk premium equity cost estimates. I have already responded to a number of the critical comments he makes. I also note that there are studies such as the one I presented in Table 17 of my direct testimony the show risk premiums appear to be higher today than in the past. Ultimately, the critical test of a risk premium analysis is whether investors might rely upon it. For example, I believe that investors may rely on the type of data ORA Staff presents in studies such as the one I report in Table 12 of my direct testimony and Rebuttal Table 4 and the type of data I presented in Table 13 of my direct testimony and in Rebuttal Table 8. Such proxies for equity costs and risk premiums are readily available to the public. I also think investors may well look at past market risk premiums to forecast what return premiums they might earn in the future and—as I explain above—would determine forward-looking estimates of risk premiums based on arithmetic, not geometric average returns. I doubt investors are aware of such studies as the "peso study" Dr. Woolridge discusses.

IV. Response to Mr. Cuthbert

Q. AT PAGE 5, MR. CUTHBERT STATES HIS BELIEF THAT HIS RECOMMENDED ROE IS BASED ON A MARKET-ORIENTED ANALYSIS THAT IS CONSISTENT WITH THE PAST ANALYSIS USED BY THE COMMISSION IN D.04-07-043 (A.02-11-044) AND IS

ALSO CONSISTENT WITH RECENT DECISIONS MADE BY THE COMMISSION TO DETERMINE REQUIRED RETURNS ON EQUITY FOR WATER UTILITIES. IS IT?

A. No, he is wrong. In A.02-11-044 (last Fontana case), ORA recommended an ROE for San Gabriel of 9.43% (Water and Natural Gas Branch's Report on the Cost of Capital for San Gabriel Valley Water Fontana District, dated July 2003, Table 1-1). Subsequently, the Commission found a 10.10% ROE to be reasonable. In D.04-07-034, dated July 2004, the Commission found:

> "On balance, we conclude that an ROE at the upper end of ORA's range of 8.61% – 10.24% is reasonable and appropriately recognize the business risk facing San Gabriel. Accordingly, we adopt a 10.10% ROE for the period 2003-2006."

That decision determined San Gabriel required a risk premium above ORA's recommended ROE of 67 basis points (10.10% minus 9.43% = 0.67%). In San Gabriel's more recent Los Angles case (A.04-09-005), ORA Staff recommended an ROE of 9.40% and the Company and the Staff settled that ROE at 10.10%, a premium of 70 basis points above the ORA cost of equity. If indeed Mr. Cuthbert had used recent methods used by the Commission to determine the ROE for San Gabriel, that ROE would be 67 to 70 basis points higher than ROEs indicated by the standard financial models used by ORA.

ORA Staff has updated cost of equity estimates made with Staff's standard financial models in the Suburban Water System case (A.05-08-034), dated November 28, 2005. Above, I showed that if the risk premium analysis in that case is updated and made consistent with data used in past cases, the indicated cost of equity for the ORA sample is 9.90%. In June 2005, ORA signed a stipulation in the Apple Valley Ranchos GRC, in which it agreed that an update of the Staff financial models used by ORA to determine ROE for its sample of six water utilities was 9.85% as of May 2005.

This information allows one to compute an updated range of equity costs for San Gabriel that are consistent with "recent decisions made by the Commission" and updated estimates of the cost of equity ORA made with ORA Staff's standard financial models. That range of estimates is as follows:

	ORA Recommended ROE for its Sample	Additional Basis Points for San Gabriel	Indicated Required Equity Return for San Gabriel
Top of Range	9.90%	70	10.60%
Bottom of Range	9.85%	67	10.52%

While I do not agree that a return as low as 10.5% to 10.6% is a fair rate of return for San Gabriel, it is clear Mr. Cuthbert's estimate of an 8.9% ROE is significantly below, and *not* consistent with, past Commission decisions and past ROE estimates made by ORA Staff.

Q. AT PAGE 9, MR. CUTHBERT LISTS 12 MAJOR RISKS CONSIDERED BY POTENTIAL INVESTORS. DID HE MISS THE MOST IMPORTANT RISK CONSIDERATION FOR INVESTORS OF UTILITIES?

A. Yes. Undoubtedly, the most import risk factor is regulatory risk. Mr. Cuthbert does not even mention it is a concern to investors. ORA Staff agrees regulatory risk is the paramount concern of investors. In its report in A.05-08-034, for example, ORA Staff states "Given the nature of the industry, the business risk of a regulated utility consists primarily of regulatory risk". (ORA Cost of Capital Report, page 3-1) This is important because both *Value Line* and Regulatory Research Associates report the regulatory climate in California has above-average risk. It is also important because Mr. Cuthbert apparently has not recognized this important risk factor in his analysis.

Q. AT PAGE 10, MR. CUTHBERT STATES THAT BASED ON CHANGES IN INTEREST RATES, HE WOULD EXPECT THE CURRENT COST OF EQUITY CAPITAL FOR SAN GABRIEL TO BE LOWER THAN AUTHORIZED RETURNS SET IN THE PAST. DO YOU HAVE A RESPONSE?

A. Yes. Costs of capital depend on more factors than simple changes in interest rates. The ORA Staff estimates of costs of equity made with the same financial models ORA Staff used in San Gabriel's last two cases now indicate its water utilities sample has a cost of equity that is higher, not lower, than when San Gabriel's authorized ROE was set at 10.10%.

Q. DO YOU HAVE ANY RESPONSES TO MR. CUTHBERT'S DCF EQUITY COST ESTIMATES?

A. Yes. At page 13, Mr. Cuthbert suggests his DCF analysis was conducted in a manner consistent with past Commission decisions. It was not. The DCF analysis ORA conducted in A.02-11-044 (Fontana's last case) indicated a cost of equity for the ORA sample of six water utilities was 8.61%. That same DCF method now indicates a cost of equity for the ORA sample of 9.27%, an increase in the indicated benchmark cost of equity of 66 basis points. While I do not agree that a cost of equity as low as 9.27% is a reasonable estimate of the cost of equity for the ORA sample, there is no doubt that Mr. Cuthbert is wrong.

Q. AT PAGE 15, MR. CUTHBERT EXPLAINS THAT HE HAS INCREASED HIS ESTIMATES OF CURRENT DIVIDEND YIELDS BY ONLY ONE-HALF OF THE GROWTH RATE. IS SUCH A METHOD APPROPRIATE?

A. No. I addressed this issue in Section IV, above.

Q. WHAT ARE THE PRIMARY FLAWS IN MR. CUTHBERT'S ESTIMATES OF GROWTH?

A. Mr. Cuthbert discusses his development of growth rates at pages 21-22. There are two primary flaws. The first flaw is in Exhibit RWC-3, page 3 of 4. In this table Mr. Cuthbert, departs from the "methodology consistent with the Commission approved methodology" and reports his estimates (however he determined them is not explained) of sustainable growth he attributes to *Value Line* instead of *Value Line's* forecasts of EPS growth. The latter is relied upon by ORA Staff, not the former. My Rebuttal Table 14 restates Exhibit RWC-3, page 3 of 4 with the *Value Line* forecasts of EPS growth that are comparable to the values Mr. Cuthbert reports for Zacks and Thomson. My source for estimates of EPS growth is *Value Line*. With this correction, Mr. Cuthbert's estimate of average growth for *Value Line* increases from 6.7% to 10.17% and the overall average of analysts' forecasts of growth increases from 6.8% to 7.6%.

Q. WHAT IS THE OTHER PRIMARY FLAW?

A. The other primary flaw is Mr. Cuthbert includes numerous estimates of costs of equity shown on Exhibit RWC-3, page 4 of 4 that are below the cost of Baa debt expected during the period in which San Gabriel's new rates will be in place. The Federal Energy Regulatory Commission ("FERC") deletes from consideration any equity cost estimates that are below the cost of investment grade debt. I agree with the FERC. It is nonsense to assume the cost of equity for a more risky water utility could be lower than investment grade debt.

Q. IF YOU CORRECT JUST THESE TWO FLAWS, WHAT HAPPENS TO MR. CUTHBERT'S DCF ESTIMATE OF THE COST OF EQUITY?

A. It increases to 10.0%. DRI forecasts that rates for Baa debt will average 7.56% during the 2006 to 2009 period. See Rebuttal Table 3. If all ROE estimates reported by Mr. Cuthbert that are below 7.56% are not included in the averages he computes, his low ROE estimate increases from 6.09% (which itself is below the expected cost of investment grade debt) to 9.5%. If I further correct his first flaw and revise the estimates of average analysts estimates of growth, his High ROE in Exhibit RWC - 3, page 4 of 4 increases from 10.01% to 10.61% and the indicated cost of equity with the method he describes at page 16 (median between the two values) becomes 10.0%.

Q. ARE THERE ANY PROBLEMS WITH HIS RISK PREMIUM APPROACH?

A. Yes. Mr. Cuthbert discusses his risk premium approach at pages 22-23. Mr. Cuthbert claims he is attempting to follow Commission methodology. But when he applies his risk premium approach, he relies upon current instead of forecasted interest rates. Commission policy is to rely on forecasted interest rates for the period new tariffs will be in effect. I have addressed this issue above and explained why it is conceptually appropriate to rely on forecasted interest rates.

Q. WHAT WOULD BE HIS RISK PREMIUM EQUITY COST ESTIMATE BASED ON FORECASTED 10-YEAR TREASURY RATES FOR THE 2006-2009 PERIOD WHEN NEW RATES WILL BE IN PLACE FOR SAN GABRIEL?

A. The equity cost estimates would have an average of 10.72%. It is found by adding the DRI forecast of 10-year Treasury note rates of 5.41% to an average of the 5-year and 10-year risk premiums of 5.29% and 5.32% he estimates in Exhibit RWC-4 page 1 of 1.

Q. AT PAGE 19, MR. CUTHBERT REPORTS THE FINANCIAL STRENGTH OF SAN GABRIEL BASED ON HIS REVIEW OF FINANCIAL RATIOS THAT ARE OFTEN RELIED UPON BY S&P. DO YOU HAVE ANY COMMENT?

A. Yes, the ratios have no relationship to ratios being used for rate-making for San Gabriel and thus are not useful. The Commission has adopted a 60% hypothetical equity ratio for San Gabriel in two past cases and Mr. Cuthbert has proposed an even lower one. Mr. Cuthbert's testimony at page 19 doesn't tell us anything and is inconsistent with the equity ratio he has proposed.

Q. AT PAGE 24, MR. CUTHBERT COMPARES HIS 8.9% ROE RECOMMENDATION TO THE COST OF Baa BONDS. HE SUGGESTS AN ROE FOR SAN GABRIEL THAT IS 280 BASIS POINTS HIGHER THAN THE COST OF Baa BONDS IS REASONABLE. DO YOU HAVE A RESPONSE?

A. Yes. He is looking at the wrong period to determine the cost of Baa bonds. Rebuttal Table 3 reports DRI's forecast of the cost of Baa bonds is 7.56% during the 2006-2009 period when new rates will be in place. If a 280 basis point spread over Baa rates is reasonable—as Mr. Cuthbert suggests—his criteria supports an equity cost of 10.36% during 2006-2009. The 280 basis point spread certainly does not support a ROE recommendation as low as 8.9%.

Q. AT PAGE 28, MR. CUTHBERT CRITICIZES YOU FOR DROPPING CONNECTICUT WATER SERVICE FROM YOUR DCF ANALYSIS. DO YOU HAVE A RESPONSE?

A. Yes. The issue is there is no reliable way to forecast growth for Connecticut Water Service. An examination of Mr. Cuthbert's Exhibit RWC - 3, page 4 of 4 validates my decision. He provides two estimates of growth and associated equity cost estimates for Connecticut Water Service. The first is derived with historical data to produce a growth rate estimate of 2.59% and a cost of equity estimate of 5.84%. Baa rated bonds are expected to yield 7.56% during 2006-2009 (Rebuttal Table 3), thus that equity cost is not credible. Why would someone buy a common stock that is expected to return less than an investment grade bond? The FERC agrees and throws out such implausible equity cost estimates when it determines costs of equity.

His other equity cost for Connecticut Water Service is also not credible. In his footnote explaining how he determined growth of 5.32%, Mr. Cuthbert says "Estimates for Connecticut Water Service and SJW Corporation estimated using differential of analysts' projections and historical growth for the other four companies". Whatever that means, he does not tell us. But whatever he did, his method creates a different growth rate for SJW Corp than he uses for Connecticut Water even though he states he is doing the same thing to estimate growth for each utility. Investors are not stupid, and obviously expect Connecticut Water Service to have higher growth than it had in the past or they would not pay prices for its stock that pushes dividend yields down to 3.61%. But we have no idea if they expect future growth to be 5.32%, 8.0% or some other percentage. Mr. Cuthbert cannot make a silk purse (reasonable growth rate estimate) out of a cow's ear (available data). It is better to exclude Connecticut Water Service from the DCF estimate.

Q. AT PAGE 29, HE SAYS THE ARGUMENTS I PRESENT TO EXPLAIN WHY SAN GABRIEL REQUIRES A RISK PREMIUM ABOVE THE COST OF EQUITY FOR THE ORA SAMPLE ARE SPECIOUS. DO YOU HAVE A RESPONSE?

A. I have responded to a similar criticism by Dr. Woolridge above and do not repeat all of my prior response. I limit my comments here to two points. One is Dr. Woolridge agrees that some—albeit small—premium is required because San Gabriel is smaller than the average sample company. The other is that the Commission has provided San Gabriel a higher premium above ORA's estimates of the cost of equity for the ORA sample than it has provided for two other water utilities. (See Table 13-3, ORA Report on the Results of Operations of Apple Valley Ranchos Water Company,A.05-02-055, May 20, 2005)

Q. AT PAGE 30, HE CONTENDS THAT YOUR DECISION TO BASE YOUR GROWTH RATE ESTIMATE ON CONCEPTUALLY CORRECT MEASURES OF GROWTH BIASES YOUR RESULTS? DO YOU AGREE?

A. No. I have responded to this argument above.

Q. AT PAGE 31 HE ARGUES THAT YOUR USE OF ONLY TREASURY SECURITIES BIASES YOUR RISK PREMIUM ANALYSIS. IS HE CORRECT?

A. No. The primary reason I have based my RP analyses on Treasury securities is to make my analysis comparable with the RP analysis ORA Staff usually presents. Historically, ORA Staff has presented its risk premium estimates using corporate bonds as well as Treasuries but currently relies on only Treasury securities. Also, in a case I prepared in Arizona, I presented an analysis comparable to the one shown in Table 14 of my direct testimony using 10-year Treasuries as one measure of the interest rate and Baa bond rates as another. Those two analyses produced exactly the same (rounded to one decimal point) forecast of the cost of equity. See Attachment_(TMZ-6).

Q. DOES THIS COMPLETE YOUR PREFILED REBUTTAL TESTIMONY?

A. Yes.

San Gabriel Valley Water Company

Rebuttal Table 1

Summary of Results Reported in ORA Tables 2-2, 2-3 and 2-4 [a/]

ORA Table 2-2: Current Annualized Dividend Yields

	3-Month Average D_0/P_0	6-Month Average D_0/P_0	12-Month Average D_0/P_0
Average for ORA Sample	3.03%	3.20%	3.06%

ORA Table 2-3: Average Historical Growth Rates

	Earnings Growth	Dividend Growth	Sustainable Growth	Overall Average Growth
5 Year Average:	5.56%	2.67%	2.63%	3.62%
10 Year Average:	5.90%	2.56%	2.90%	3.79%
Overall Average Past Growth Rate:				3.70%

ORA Table 2-4: Forecasted Earnings Growth Rates

Average of Analysts' Forecasts of Growth reported by Zacks, First Call, Value Line and Reuters that are Available for the ORA Sample Utilites	8.27%

Notes and Sources:

a/ Reported by ORA Staff, in Cost of Capital Report for Suburban Water System, Application 05-08-034, dated November 28, 2005. Averages are for the ORA water Utilties sample which contains American States, Aqua America, Calfornia Water, Connecticut Water Service, Middlesex Water and SJW Corp.

b/ Detail for the six utilties in the ORA sample are available in ORA Report on the Cost of Capital of Suburban Water System, A.05-08-034, dated November 28, 2005.

12/9/05

San Gabriel Valley Water Company

Rebuttal Table 2

Reproduction of ORA DCF Estimates in A.05-08-034

Components		
3-month Current Yield	3.03%	a/
Growth Rate	5.99%	b/
Expected Yield	3.21%	c/
ROE	9.2%	d/
6-month Current Yield	3.20%	a/
Growth Rate	5.99%	b/
Expected Yield	3.39%	c/
ROE	9.4%	d/
12-month Current Yield	3.06%	a/
Growth Rate	5.99%	b/
Expected Yield	3.24%	c/
ROE	9.2%	d/
Range of ROE Estimates for Benchmark Water Utilities	9.27%	

Notes and Sources:

a/ From Rebuttal Table 1.

b/ An average of the historic and forecasted growth rates reproduced in Rebuttal Table 1.

c/ Expected yield = $D_1/P_0 = D_0/P_0 * (1 + g)$

d/ ROE = $D_1/P_0 + g$

12/09/05

San Gabriel Valley Water Company

Rebuttal Table 3

ORA Staff Forecasts of Treasury Securities Rates and
Baa Corporate Bond Rates for 2006-2009

Description	2006	2007	2008	2009	Average
10-Year Treasury Bonds	5.20%	5.32%	5.43%	5.67%	5.41%
Long-term Treasury Bonds	5.36%	5.51%	5.66%	5.90%	5.61%
Seasoned Baa Corporate Bonds	7.24%	7.42%	7.61%	7.98%	7.56%

Notes and Sources:
a/ DRI Forecasts for November 2005 provided by ORA in A.05-08-034.

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Rebuttal Table 4

ORA Staff Risk Premium Analysis with Corrected and Updated Data

	Return on Equity[a/]	Annual Averages Long-term Treasury[b/]	Annual Averages 10-Year Treasury[b/]	Risk Premiums Long-term Treasury	Risk Premiums 10-Year Treasury
1995	11.20%	6.88%	6.57%	4.32%	4.63%
1996	12.02%	6.71%	6.44%	5.31%	5.58%
1997	11.82%	6.61%	6.35%	5.21%	5.47%
1998	10.90%	5.58%	5.26%	5.32%	5.64%
1999	10.59%	5.87%	5.65%	4.72%	4.94%
2000	9.88%	5.94%	6.03%	3.94%	3.85%
2001	10.37%	5.49%	5.02%	4.88%	5.35%
2002	10.63%	5.43%	4.61%	5.20%	6.02%
2003	9.53%	5.02%	4.01%	4.51%	5.52%
2004	9.98%	5.10%	4.27%	4.88%	5.71%
	10-Year Average Premium			4.83%	5.27%
	5-year Average Premium			4.68%	5.29%
	Forecasted Interest Rates for 2006-2009[c/]			5.61%	5.41%
	Projected Returns on Equity				
	10-Year Average			10.44%	10.68%
	5-Year Average			10.29%	10.70%
	Average			10.53%	

Notes and Sources:

_a/ Data for 1995-2003 from ORA Cost of Capital Report, Table 2-7, A.04-04-040, dated November 2004. Data for 2004 from Utilities' Annual Reports to Stockholders and 10-K Reports.

_b/ Source: Table 2-7 of ORA Cost of Capital Report for Suburban, A.05-08-034 .

_c/ Source is Rebuttal Table 3.

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Rebuttal Table 5
ORA Table 2-8 from A.05-08-034 with Updated
and Corrected Data

Discounted Cash Flow Model		
Growth Rate		5.99
Three-Month ROE		9.20
Six-Month ROE		9.38
Twelve-Month ROE		9.23
DCF Average (same as ORA estimate)		9.27
Updated and Corrected Risk Premium Model		
	5-Year	10-Year
30-Year Treasury Bond	10.44	10.29
10-Year Treasury Bond	10.68	10.70
Updated and Corrected RP Average		10.53
ROE Estimate for ORA Sample		9.90

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Rebuttal Table 6

DCF Estimates Based on Conceptually Correct
Measure of Growth Reported by ORA

3-month Current Yield	3.03%	a/
Growth Rate	8.27%	b/
Expected Yield	3.28%	c/
ROE	11.55%	d/
6-month Current Yield	3.20%	a/
Growth Rate	8.27%	b/
Expected Yield	3.46%	c/
ROE	11.73%	d/
12-month Current Yield	3.06%	a/
Growth Rate	8.27%	b/
Expected Yield	3.31%	c/
ROE	11.58%	d/
DCF Estimate for ORA Sample	11.62%	

Notes and Sources:
a/ From Rebuttal Table 1.
b/ Average of analysts' estimates of growth from Rebuttal Table 1.
c/ Expected yield = $D_1/P_0 = D_0/P_0 * (1 + g)$
d/ ROE = $D_1/P_0 + g$

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Rebuttal Table 7

Summary of Model Results Based on ORA Data
and Conceptually Correct Estimates

Conceptually Correct DCF Analysis–[a/]	
Growth Rate	8.27%
Three-Month ROE	11.55%
Six-Month ROE	11.73%
Twelve-Month ROE	11.58%
DCF Average	11.62%
Risk Premium Analysis	
Updated ORA Analysis–[b/]	10.53%
Equity Cost for ORA Staff Sample	11.07%

Notes and Sources:
a/ Rebuttal Table 6.
b/ Rebuttal Table 4.

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Rebuttal Table 8

Risk Premium Analysis Using Authorized Returns on Equity
As the Proxies for the Costs of Equity for the Water Utilties Sample

	Authorized Returns on Equity[a]	Annual Averages 30-Year Treasury[b]	10-Year Treasury[b]	Risk Premiums 30-Year Treasury	10-Year Treasury
1995	11.51%	6.88%	6.57%	4.63%	4.94%
1996	11.58%	6.71%	6.44%	4.87%	5.14%
1997	11.18%	6.61%	6.35%	4.57%	4.83%
1998	11.06%	5.58%	5.26%	5.48%	5.80%
1999	11.12%	5.87%	5.65%	5.25%	5.47%
2000	11.12%	5.94%	6.03%	5.18%	5.09%
2001	10.86%	5.49%	5.02%	5.37%	5.84%
2002	10.62%	5.43%	4.61%	5.19%	6.01%
2003	10.62%	5.02%	4.01%	5.60%	6.61%
2004	10.48%	5.10%	4.27%	5.38%	6.21%
	10-Year Average Premium[a]			5.15%	5.59%
	5-year Average Premium[a]			5.34%	5.95%
	Forecasted Interest Rates for 2006-2009[c]			5.61%	5.41%
	Projected Returns on Equity				
	10-Year Average			10.76%	11.00%
	5-Year Average			10.95%	11.36%
	Average			11.02%	

Notes and Sources:

a/ Sources are Year-end AUS (formerly CA Turner) *Utility Reports* for various years for the water utilties sample.

_b/ Source: Table 2-7 of ORA Cost of Capital Report for Suburban, A.05-08-034 .

_c/ Source is Rebuttal Table 4.

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Rebuttal Table 9

Beta Estimates for Water Utilities Now and Over Time

A. Current Beta Estimates for ORA Staff Sample:

		Value Line-[a/]	Thomson-[b/]	Reuters-[c/]	Average for 3 Investor Services	Average for Value Line and Reuters
1	American States	0.75	0.79	1.41	0.98	1.08
2	Aqua America	0.80	0.66	1.00	0.82	0.90
3	California Water	0.75	0.86	1.47	1.03	1.11
4	Connecticut Water Service	0.75	na	1.31	1.03	1.03
5	Middlesex Water	0.75	0.77	1.37	0.96	1.06
6	SJW Corporation	0.65	na	1.18	0.92	0.92
	Average	0.74	0.77	1.29	0.96	1.02

B. Betas Reported for 3 Largest Water Utilites (2001 to 2005):

		December 2001	December 2004	December 2005	Precentage Increase in Beta Risk
1	American States	0.60	0.70	0.75	25.0%
2	Aqua America	0.60	0.75	0.80	33.3%
3	California Water	0.60	0.75	0.75	25.0%
	Average	0.60	0.73	0.77	28%

Notes and Sources:
a/ Value Line, December 2, 2005.
b/ Mr. Cuthbert, Table RWC-2, page 1 of 7.
c/ From the Internet, December 2, 2005.

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Rebuttal Table 10

DCF Analysis for Two Additional Utilites Considered by Dr. Woolridge[a/]

A. Current Annualized Average Dividend Yields[b/]

		3-Month Average D_0/P_0	6-Month Average D_0/P_0	12-Month Average D_0/P_0
1	Artesian Resources	2.94%	2.92%	3.06%
2	York Water	2.66%	2.80%	3.05%
	Average	2.80%	2.86%	3.06%

B. Analysts' Estimates of Future Growth[c/]

		Zack's[d/]	First Call[d/]	S&P[e/]	Reuters[d/]
1	Artesian Resources	8.5%	8.5%	9.0%	8.5%
2	York Water	7.3%	7.3%	7.0%	7.3%
	Average of Estimates		7.9%		

C. DCF Estimate for the Additional Utilites[f/]:

	3-Month Average Yield	6-Month Average Yield	12-Month Average Yield
D_0/P_0	2.80%	2.86%	3.06%
g	7.92%	7.92%	7.92%
D_1/P_0	3.02%	3.09%	3.30%
Average Equity Cost	10.9%	11.0%	11.2%

Notes and Sources:

a/ Only two of the four additional utilities considered by Dr. Woolridge are considered due to the following reasons: SW Water eliminated due to only 38% of revenues from water operations. Pennichuck Corp eliminated due to lack of data.

b/ Yields computed with method ORA used A.05-08-034 and in past cases. Recognizes the time value of money.

c/ Value Line forecasts are not available.

d/ From the Internt on 12/2/05.

e/ S&P Earnings Guide for November 2005.

f/ Method used by ORA in its Cost of Capital Report for Suburban Water (A.05-08-034) dated November 28, 2005.

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Rebuttal Table 11

Demonstration–[a,c] That Arithmetic Average Return is Required to Obtain Expected Ending Value of Asset in Dr. Woolridge's Example

		Starting Value	Annual Returns–[a] Return	Annual Returns–[a] Percentage	Value at End of Future Year 1	Value at End of Future Year 2	Equal–[b] Chance of Each Outcome	Expected Ending Value	Return Required to Achieve Opportunity Cost Ending Value
1	Dr. Woolridge	$100	High	100.0%	$200	$400.00 $100.00	$100.00 $25.00	$156.25	25.0%
			Low	-50.0%	$50	$100.00 $25.00	$25.00 $6.25		
2	Treasury bond	$100	Same	6.0%	$106	$112.36 $112.36	$28.09 $28.09	$112.36	6.0%
			Same	6.0%	$106	$112.36 $112.36	$28.09 $28.09		

Sources and Notes:
a/ Demonstration assumes either the high return or the low return is expected.
b/ Each potential outcome is given a weight of 25%.
c/ Conceptual support for this example is provided in Attachments__(TMZ- 1) and__(TMZ- 2).

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Rebuttal Table 12

Acutal and Forecasted Inflation
1986 - 2001

Years	Projected CPI	Actual CPI	Difference
1986	5.00%	1.90%	3.10%
1987	5.30%	3.70%	1.60%
1988	5.50%	4.10%	1.40%
1989	5.00%	4.80%	0.20%
1990	5.00%	5.40%	-0.40%
1991	5.00%	4.20%	0.80%
1992	4.50%	3.00%	1.50%
1993	5.00%	3.00%	2.00%
1994	4.70%	2.60%	2.10%
1995	4.60%	2.80%	1.80%
1996	4.40%	2.90%	1.50%
1997	3.20%	2.30%	0.90%
1998	3.50%	1.50%	2.00%
1999	3.30%	2.20%	1.10%
2000	3.30%	3.40%	-0.10%
2001	2.80%	2.80%	0.00%
Average	4.38%	3.16%	1.22%

Source: Annual Editions of Value Line Investment Survey Survey, Issue No. 1, dated December of the respective years.

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Rebuttal Table 13

Examination of Bias in Real and Nominal Value Line ROE Forecasts for 8 Natural Gas Utilities
1977 to 1998

		Nominal Returns			Inflation[c]			Real Returns		
	Date of Value Line Issue	Average Value Line Forecasted ROE (1977-1994)	Average Actual Earned ROE 4 Years Later (1981-1998)	Difference Between Forecasted and Actual Nominal ROEs	Expected Inflation	Realized Inflation	Difference Between Forecasted and Actual Inflation	Average Value Line Forecasted ROE (1977-1994)	Actual Earned ROE 4 Years Later (1981-1998)	Difference Between Forecasted and Actual Real ROEs
1	Oct-77	13.00%	11.32%	1.68%	5.50%	9.70%	-4.20%	7.50%	1.62%	5.88%
2	Jan-79	12.81%	11.91%	0.90%	5.50%	3.90%	1.60%	7.31%	8.01%	-0.70%
3	Oct-80	14.13%	15.86%	-1.73%	8.25%	3.70%	4.55%	5.88%	12.16%	-6.28%
4	Oct-81	15.06%	13.81%	1.25%	7.50%	3.20%	4.30%	7.56%	10.61%	-3.05%
5	Oct-82	14.00%	12.07%	1.93%	5.20%	2.60%	2.60%	8.80%	9.47%	-0.67%
6	Oct-83	13.94%	12.28%	1.66%	5.00%	3.00%	2.00%	8.94%	9.28%	-0.34%
7	Oct-84	15.13%	14.67%	0.46%	5.50%	3.70%	1.80%	9.63%	10.97%	-1.34%
8	Oct-85	15.56%	13.12%	2.44%	4.50%	4.20%	0.30%	11.06%	8.92%	2.14%
9	Oct-86	13.63%	12.41%	1.21%	3.80%	4.40%	-0.60%	9.83%	8.01%	1.81%
10	Oct-87	13.19%	11.62%	1.56%	4.50%	4.00%	0.50%	8.69%	7.62%	1.06%
11	Oct-88	13.13%	10.88%	2.24%	4.60%	2.70%	1.90%	8.53%	8.18%	0.34%
12	Oct-89	13.50%	12.58%	0.92%	4.60%	2.60%	2.00%	8.90%	9.98%	-1.08%
13	Oct-90	14.00%	11.71%	2.29%	4.30%	2.30%	2.00%	9.70%	9.41%	0.29%
14	Oct-91	14.13%	11.34%	2.78%	3.70%	2.50%	1.20%	10.43%	8.84%	1.58%
15	Oct-92	14.38%	13.08%	1.29%	3.90%	2.10%	1.80%	10.48%	10.98%	-0.51%
16	Dec-93	12.56%	12.62%	-0.06%	2.40%	2.00%	0.40%	10.16%	10.62%	-0.46%
17	Dec-94	12.19%	11.20%	0.99%	2.80%	1.30%	1.50%	9.39%	9.90%	-0.51%
	Average	13.78%	12.50%	1.28%	4.80%	3.41%	1.39%			-0.11%

Notes and Source:

a/ Source of Study: Testimony of T. Zepp in Oregon PUC Docket UG-132, Exhibit UG-132/NWN/5000.

b/ ROEs are annual averages for 8 natural gas distribution companies for each year.

c/ Based on forecasted and realized values for the GNP deflator.

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Rebuttal Table 14

Restatement of Mr. Cuthbert's Estimates of Analysts' Forecasts of Growth

	Companies	Zacks-[a/]	Thomson-[a/]	Value Line-[b/]	Average
1	American States	6.00%	4.50%	12.00%	7.50%
2	Aqua America	8.90%	9.50%	10.00%	9.47%
3	California Water	7.70%	6.50%	8.50%	7.57%
4	Connecticut Water Service				
5	Middlesex Water	6.00%	6.00%	na	6.00%
6	SJW Corporation				
	Average	7.15%	6.63%	10.17%	7.63%

Sources:
Exhibit RWC - 3, page 3 of 4
Exhibit JRW-7, page 4 of 5.

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ATTACHMENT_(TMZ-1)

PRINCIPLES OF CORPORATE FINANCE

SEVENTH EDITION

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much that averages taken over short periods are meaningless. Our only hope of gaining insights from historical rates of return is to look at a very long period.[3]

Arithmetic Averages and Compound Annual Returns

Notice that the average returns shown in Table 7.1 are arithmetic averages. In other words, Ibbotson Associates simply added the 75 annual returns and divided by 75. The arithmetic average is higher than the compound annual return over the period. The 75-year compound annual return for the S&P index was 11.0 percent.[4]

The proper uses of arithmetic and compound rates of return from past investments are often misunderstood. Therefore, we call a brief time-out for a clarifying example.

Suppose that the price of Big Oil's common stock is \$100. There is an equal chance that at the end of the year the stock will be worth \$90, \$110, or \$130. Therefore, the return could be −10 percent, +10 percent, or +30 percent (we assume that Big Oil does not pay a dividend). The *expected* return is ⅓(−10 +10 +30) = +10 percent.

If we run the process in reverse and discount the expected cash flow by the expected rate of return, we obtain the value of Big Oil's stock:

$$PV = \frac{110}{1.10} = \$100$$

The expected return of 10 percent is therefore the correct rate at which to discount the expected cash flow from Big Oil's stock. It is also the opportunity cost of capital for investments that have the same degree of risk as Big Oil.

Now suppose that we observe the returns on Big Oil stock over a large number of years. If the odds are unchanged, the return will be −10 percent in a third of the years, +10 percent in a further third, and +30 percent in the remaining years. The arithmetic average of these yearly returns is

$$\frac{-10 + 10 + 30}{3} = +10\%$$

Thus the arithmetic average of the returns correctly measures the opportunity cost of capital for investments of similar risk to Big Oil stock.

The average compound annual return on Big Oil stock would be

$$(.9 \times 1.1 \times 1.3)^{1/3} - 1 = .088, \text{ or } 8.8\%,$$

[3]We cannot be sure that this period is truly representative and that the average is not distorted by a few unusually high or low returns. The reliability of an estimate of the average is usually measured by its *standard error*. For example, the standard error of our estimate of the average risk premium on common stocks is 2.3 percent. There is a 95 percent chance that the *true* average is within plus or minus 2 standard errors of the 9.1 percent estimate. In other words, if you said that the true average was between 4.5 and 13.7 percent, you would have a 95 percent chance of being right. (*Technical note*: The standard error of the average is equal to the standard deviation divided by the square root of the number of observations. In our case the standard deviation is 20.2 percent, and therefore the standard error is $20.2/\sqrt{75} = 2.3$.)

[4]This was calculated from $(1 + r)^{75} = 2{,}586.5$, which implies $r = .11$. *Technical note*: For lognormally distributed returns the annual compound return is equal to the arithmetic average return minus half the variance. For example, the annual standard deviation of returns on the U.S. market was about .20, or 20 percent. Variance was therefore $.20^2$, or .04. The compound annual return is $.04/2 = .02$, or 2 percentage points less than the arithmetic average.

less than the opportunity cost of capital. Investors would not be willing to invest in a project that offered an 8.8 percent expected return if they could get an expected return of 10 percent in the capital markets. The net present value of such a project would be

$$\text{NPV} = -100 + \frac{108.8}{1.1} = -1.1$$

Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return.

Using Historical Evidence to Evaluate Today's Cost of Capital

Suppose there is an investment project which you *know*—don't ask how—has the same risk as Standard and Poor's Composite Index. We will say that it has the same degree of risk as the *market portfolio,* although this is speaking somewhat loosely, because the index does not include all risky securities. What rate should you use to discount this project's forecasted cash flows?

Clearly you should use the currently expected rate of return on the market portfolio; that is the return investors would forgo by investing in the proposed project. Let us call this market return r_m. One way to estimate r_m is to assume that the future will be like the past and that today's investors expect to receive the same "normal" rates of return revealed by the averages shown in Table 7.1. In this case, you would set r_m at 13 percent, the average of past market returns.

Unfortunately, this is *not* the way to do it; r_m is not likely to be stable over time. Remember that it is the sum of the risk-free interest rate r_f and a premium for risk. We know that r_f varies. For example, in 1981 the interest rate on Treasury bills was about 15 percent. It is difficult to believe that investors in that year were content to hold common stocks offering an expected return of only 13 percent.

If you need to estimate the return that investors expect to receive, a more sensible procedure is to take the interest rate on Treasury bills and add 9.1 percent, the average *risk premium* shown in Table 7.1. For example, as we write this in mid-2001 the interest rate on Treasury bills is about 3.5 percent. Adding on the average risk premium, therefore, gives

$$\begin{aligned} r_m(2001) &= r_f(2001) + \text{normal risk premium} \\ &= .035 + .091 = .126, \text{ or about } 12.5\% \end{aligned}$$

The crucial assumption here is that there is a normal, stable risk premium on the market portfolio, so that the expected *future* risk premium can be measured by the average past risk premium.

Even with 75 years of data, we can't estimate the market risk premium exactly; nor can we be sure that investors today are demanding the same reward for risk that they were 60 or 70 years ago. All this leaves plenty of room for argument about what the risk premium *really* is.[5]

Many financial managers and economists believe that long-run historical returns are the best measure available. Others have a gut instinct that investors

[5]Some of the disagreements simply reflect the fact that the risk premium is sometimes defined in different ways. Some measure the average difference between stock returns and the returns (or yields) on long-term bonds. Others measure the difference between the compound rate of growth on stocks and the interest rate. As we explained above, this is not an appropriate measure of the cost of capital.

ATTACHMENT_(TMZ-2)

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For example, if bond yields rise unexpectedly, investors can receive a higher coupon payment from a newly issued bond than from the purchase of an outstanding bond with the former lower-coupon payment. The outstanding lower-coupon bond will thus fail to attract buyers, and its price will decrease, causing its yield to increase correspondingly, as its coupon payment remains the same. The newly priced outstanding bond will subsequently attract purchasers who will benefit from the shift in price and yield; however, those investors who already held the bond will suffer a capital loss due to the fall in price.

Anticipated changes in yields are assessed by the market and figured into the price of a bond. Future changes in yields that are not anticipated will cause the price of the bond to adjust accordingly. Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return. The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.

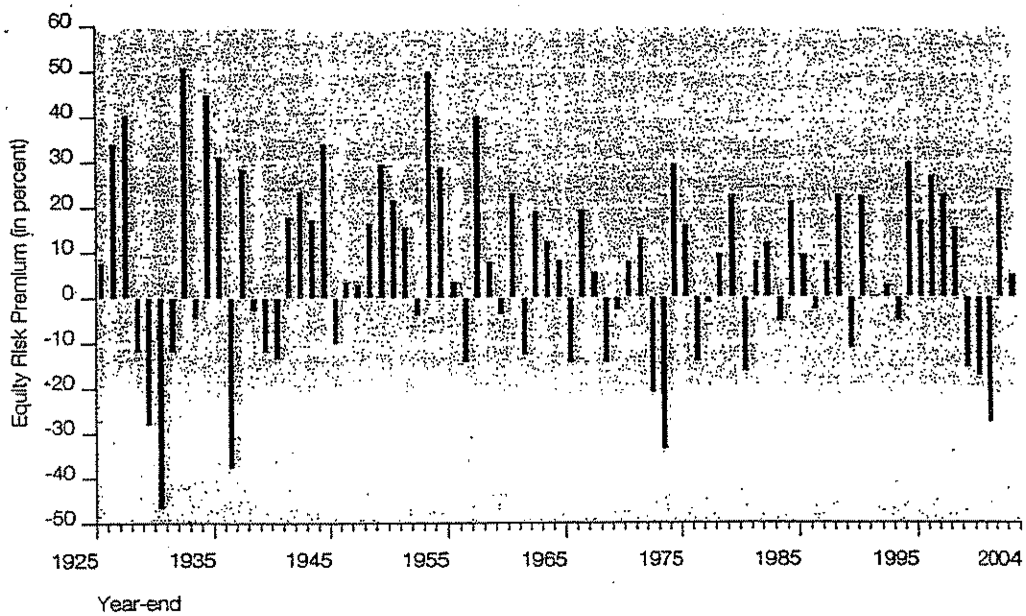
Arithmetic versus Geometric Means

The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return.

The argument for using the arithmetic average is quite straightforward. In looking at projected cash flows, the equity risk premium that should be employed is the equity risk premium that is expected to actually be incurred over the future time periods. Graph 5-3 shows the realized equity risk premium for each year based on the returns of the S&P 500 and the income return on long-term government bonds. (The actual, observed difference between the return on the stock market and the riskless rate is known as the realized equity risk premium.) There is considerable volatility in the year-by-year statistics. At times the realized equity risk premium is even negative.

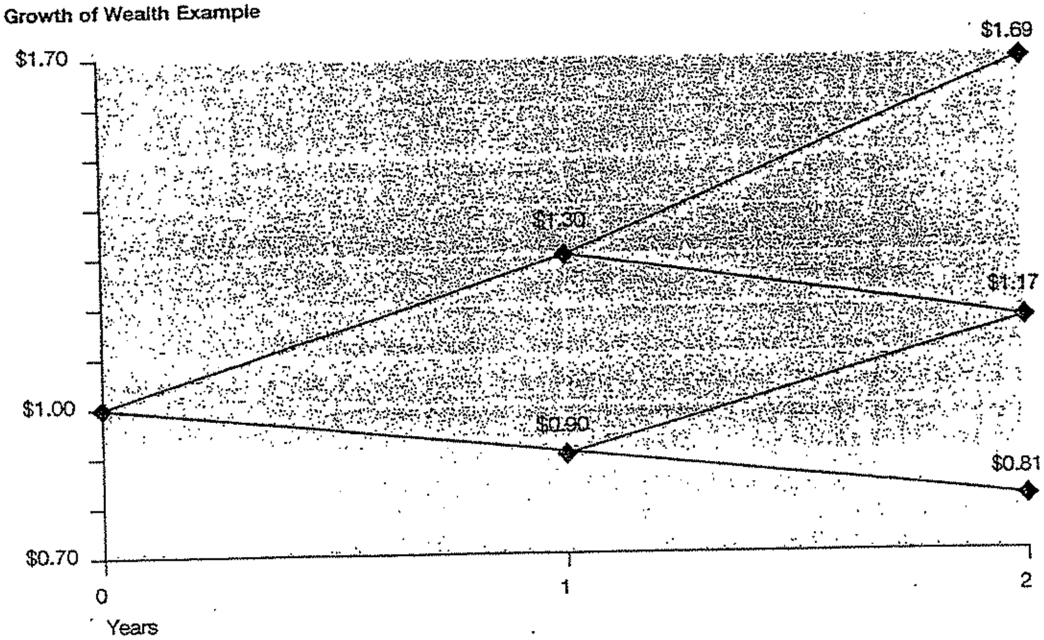
Graph 5-3

Realized Equity Risk Premium Per Year
1926–2004



To illustrate how the arithmetic mean is more appropriate than the geometric mean in discounting cash flows, suppose the expected return on a stock is 10 percent per year with a standard deviation of 20 percent. Also assume that only two outcomes are possible each year— +30 percent and –10 percent (i.e., the mean plus or minus one standard deviation). The probability of occurrence for each outcome is equal. The growth of wealth over a two-year period is illustrated in Graph 5-4.

Graph 5-4
Growth of Wealth Example



The most common outcome of \$1.17 is given by the geometric mean of 8.2 percent. Compounding the possible outcomes as follows derives the geometric mean:

$$[(1+0.30)\times(1-0.10)]^{1/2}-1=0.082$$

However, the expected value is predicted by compounding the arithmetic, not the geometric, mean. To illustrate this, we need to look at the probability-weighted average of all possible outcomes:

(0.25 × \$1.69) =	\$0.4225
+ (0.50 × \$1.17) =	\$0.5850
+ (0.25 × \$0.81) =	\$0.2025
Total	\$1.2100

Therefore, \$1.21 is the probability-weighted expected value. The rate that must be compounded to achieve the terminal value of \$1.21 after 2 years is 10 percent, the arithmetic mean:

$$\$1\times(1+0.10)^2=\$1.21$$

The geometric mean, when compounded, results in the median of the distribution:

$$\$1\times(1+0.082)^2=\$1.17$$

The arithmetic mean equates the expected future value with the present value; it is therefore the appropriate discount rate.

ATTACHMENT_(TMZ-3)

Money

Posted 4/23/2004 12:20 AM

Investors finally see picture of profit

By Matt Krantz, USA TODAY

After ignoring Corporate America's boffo earnings season all week, investors are finally waking up.

Stocks soared in a broad rally Thursday that traders mostly attributed to the sudden realization the stream of first-quarter earnings reports has been better than already-lofty expectations.

The Dow Jones industrial average rose 144 points to 10,461 for its best gain in a month.

With blowout earnings pouring in from companies ranging from American International Group to Caterpillar, earnings season has stolen investors' attention from the recent fixation over the threat of higher interest rates. "I hate to be an overwhelming bull, but (the earnings season) is amazing," says Scott Pape, portfolio manager at CastleArk Management.

It's not like the strong earnings just started landing Thursday. More than half the companies in the Standard & Poor's 500 have reported, and 78% of them have beat estimates, Thomson First Call says. Typically, only 58% of companies beat forecasts.

So far, operating earnings have been nearly 22% higher than the first quarter last year, says Howard Silverblatt at S&P. While that's down slightly from the 24.6% growth in the fourth quarter of 2003, if companies deliver what's expected, S&P 500 earnings will be a record this quarter, he says.

With the abundance of good earnings news, the question is why has it taken investors so long to notice. Some explanations:

•**Reduced fears of skyrocketing interest rates.** Federal Reserve Chairman Alan Greenspan, in his comments to Congress Wednesday, quieted fears of a massive and sudden spike in short-term interest rates. "People realized that an aggressive hiking of short-term rates is probably not likely," says Gary Tapp at SunTrust Robinson Humphrey.

•**Acknowledgment stocks can move higher, even when rates rise.** Though investors have initially panicked, the Dow has actually gained an average of 8% in the year following initial interest rate increases since 1917, Ned Davis Research says.

• Sprint recombines tracking s
• Durable goods orders jump i
Add USATODAY.com headline

•Companies are bullish about the future. Not only are companies such as Caterpillar, Qualcomm and Starbucks beating estimates, but they're raising their forecasts for future earnings. "The guidance has really started to come in awfully strong," Tapp says.

•Pressure on bonds receding. The yield on the widely followed 10-year Treasury note — which moves in the opposite direction of its price — fell to 4.39% from 4.43% Wednesday as rate fears eased.

Some, like Rod Smyth, a strategist at Wachovia, are skeptical, thinking the reality of higher interest rates will derail all this happiness. "This is a relief rally," he says. "Something has got to give."

ATTACHMENT_(TMZ-4)

THE VALUE LINE
Investment Survey®

PAGES 1951-1962
File in page order in the Selection & Opinion binder.

PART 2 Selection & Opinion DECEMBER 24, 2004

The Value Line View

In This Issue

The *Selection & Opinion* Index appears on page 1986 (December 3, 2004).

In Three Parts: Part 1 is the Summary & Index. This is Part 2, Selection & Opinion. Part 3 is Ratings & Reports. Volume LX, Number 17.
Published weekly by VALUE LINE PUBLISHING, INC.
220 East 42nd Street, New York, NY 10017-5891.

ECONOMIC AND STOCK MARKET COMMENTARY

Things appear to be nicely in place on the economic front as we peer out into the early part of 2005. For example, several of the major business barometers, including those relating to industrial production and retail sales, point to additional modest increases in economic activity in the months ahead. Such resilience and a gradually brightening employment outlook are probably behind the stock market's ability to take in stride a recent sharp drop in housing starts and the Federal Reserve's monetary tightening initiatives that since late June have produced five increases in short-term interest rates.

We are cautiously optimistic that the economic upturn will continue in the new year as a whole. One reason is that the current moderate level of business activity is likely to enable the Fed to adhere to its plan of raising interest rates in small measured steps that should not prove disruptive. The recent decline in oil prices and the restrained pace of inflation further strengthen the case that the business upturn can proceed at a modest 3% to 4% rate of growth in 2005.

However, there are concerns out there as we look ahead to a new year. One potential worry is the price of oil, which, even after its recent drop, remains over $40 a barrel. The oil market, moreover, is vulnerable to an outbreak of frigid weather, to a supply disruption, or to an escalation in global hostilities. A serious misstep by the Fed is another potential threat to the modest growth and low inflation scenario we see ahead for the new year.

The stock market continues to push higher as the old year winds down. After a flattish first three quarters, the market, encouraged by the better tone on the economic front, has moved into the plus column for the year as a whole.

We think equities will remain a favored investment going into the new year. Steady economic growth, benign inflation, and relatively low interest rates have been a winning combination in the past and should support the market again in 2005, assuming that the situation does not deteriorate in the oil patch or on the international side.

Conclusion: The market outlook appears positive heading into 2005—at least for the first six months. Please refer to the inside back cover of *Selection & Opinion* for our Asset Allocation Model's current reading.

CLOSING STOCK MARKET AVERAGES AS OF PRESS TIME

	12/9/2004	12/16/2004	%Change 1 week	%Change 12 months
Dow Jones Industrial Average	10552.82	10705.64	+1.4%	+5.7%
Standard & Poor's 500	1189.24	1203.21	+1.2%	+11.9%
N.Y. Stock Exchange Composite	7048.10	7131.98	+1.2%	+14.9%
NASDAQ Composite	2129.01	2146.15	+0.8%	+11.5%
NASDAQ 100	1609.79	1607.62	-0.1%	+14.6%
American Stock Exchange Index	1386.57	1407.90	+1.5%	+24.7%
Value Line (Geometric)	390.33	397.30	+1.8%	+13.9%
Value Line (Arithmetic)	1728.63	1760.81	+1.9%	+19.8%
London (FT-SE 100)	4688.4	4735.2	+1.0%	+9.3%
Tokyo (Nikkei)	10776.63	10924.37	+1.4%	+6.4%
Russell 2000	629.19	642.23	+2.1%	+19.4%

ATTACHMENT_(TMZ-5)

THE VALUE LINE
Investment Survey®

PAGES 4179-4190
File in page order in the *Selection & Opinion* binder.

PART 2 — *Selection & Opinion* — JUNE 29, 2001

A Letter from Our Chairman

In This Issue

In Three Parts: Part 1 is the Summary & Index. This is Part 2, Selection & Opinion. Part 3 is Ratings & Reports. Volume LVI, Number 43.

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To All Subscribers of *The Value Line Investment Survey*

There has been news recently about potential conflicts of interest between security analysts and the customers of the firms they work for. Many of the possible conflicts involve investment banking, in which firms often make large profits from selling new issues of stocks or bonds, and in which a security analyst may be asked to provide a more favorable opinion about a stock or bond than he/she otherwise would have.

We want all of our subscribers to know that Value Line is not an investment bank. Our analysts' compensation is not based on commissions or fees paid to Value Line because of their recommendations. Our goal is to provide you with the most accurate information and independent advice anywhere.

We are occasionally asked if our analysts can own stock in the companies they recommend. The answer is yes. Our analysts, like those at most investment advisory organizations, can own stock. But here there are many limitations that apply to analysts and all other employees, as well. They must inform Value Line in advance and request authorization before making any trades in their own accounts, those of their immediate families, or accounts in which they have a beneficial interest. They are prohibited from trading in stocks that are being bought or sold by our own mutual funds or other Value Line-managed accounts. They are also prohibited from trading in stocks in which a Timeliness Rank is about to change. No employee may act on any Value Line information until after subscribers have been given that information.

We are proud of our record of independence, and I want to assure you that we will continue to provide the most objective and unbiased investment advice available.

Jean B. Buttner
Chairman & CEO

Jean Bernhard Buttner

CLOSING STOCK MARKET AVERAGES AS OF PRESS TIME

	6/14/2001	6/21/2001	%Change 1 week	%Change 12 months
Dow Jones Industrial Average	10690.13	10715.43	+0.2%	+2.1%
Standard & Poor's 500	1219.87	1237.04	+1.4%	-16.4%
N.Y. Stock Exchange Composite	623.96	631.08	+1.1%	-2.8%
NASDAQ OTC Composite	2044.07	2058.76	+0.7%	-49.3%
American Stock Exchange Index	921.88	906.97	-1.6%	-3.3%
Value Line (Geometric)	392.95	390.46	-0.6%	-6.0%
Value Line (Arithmetic)	1224.44	1220.60	-0.3%	+13.4%
London (FT-SE 100)	5752.5	5641.4	-1.9%	-12.9%
Tokyo (Nikkei)	12846.66	12962.43	+0.9%	-24.7%
Russell 2000	495.38	497.82	+0.5%	-5.6%

ATTACHMENT__ (TMZ-6)

ARIZONA WATER COMPANY

Docket No. W-01445A-04-0650

2004 RATE HEARING EXHIBIT NO. ___

For Test Year Ending 12/31/03

CORRECTED

DIRECT TESTIMONY & EXHIBITS

OF

Thomas M. Zepp

Arizona Water Company

Table 13

Risk Premium for Water Utilities Based on Past Earned ROEs

Panel A: Historic Data

		Earned ROE		10-Year Treasury		Risk Premium
1	1985	14.40%	a/	10.62%	d/	3.78%
2	1986	13.28%	a/	7.67%	d/	5.61%
3	1987	14.58%	a/	8.39%	d/	6.19%
4	1988	12.42%	a/	8.85%	d/	3.57%
5	1989	10.39%	a/	8.49%	d/	1.90%
6	1990	11.07%	a/	8.55%	d/	2.52%
7	1991	12.82%	a/	7.86%	d/	4.96%
8	1992	11.80%	b/	7.01%	d/	4.79%
9	1993	11.90%	b/	5.87%	d/	6.03%
10	1994	10.76%	b/	7.09%	d/	3.67%
11	1995	11.30%	b/	6.57%	d/	4.73%
12	1996	12.21%	b/	6.44%	d/	5.77%
13	1997	11.93%	b/	6.35%	d/	5.58%
14	1998	11.34%	b/	5.26%	d/	6.08%
15	1999	11.02%	b/	5.65%	d/	5.37%
16	2000	9.91%	b/	6.03%	d/	3.88%
17	2001	10.25%	b/	5.02%	d/	5.23%
18	2002	10.58%	c/	4.61%	d/	5.97%
19	Average 1985-1992	12.60%		8.43%		4.17%
20	Average 1993-2002	11.12%		5.89%		5.23%
21	Difference	-1.48%		-2.54%		1.07%
22	Slope		0.58		-0.42	

Panel B: Solve for constant in formula (risk premium = constant - slope x 10 yr Treas rate):

constant	=	risk premium	+	slope-e/	x	10 Year Treasury rate
constant	=	5.23%	+	0.42-e/	x	5.89%
constant	=	7.70%				

Panel C: Solve for current risk premium and equity cost:

Risk Premium	=	constant	-	slope	x	10 yr Treasury rate		
Risk premium	=	7.70%	-	.42	x	5.55%-f/	=	5.4%

Estimated equity cost = bond rate + risk premium = 10.9%

Notes and Sources:

a/ Source: CPUC Staff Table 3-4, Application 95-09-010 (San Gabriel Valley Water).
b/ Source: CPUC Staff Table 2-7, Application 02-09-030 (California-American Water).
c/ Source: CPUC Staff Table 2-7, Application 02-11-044 (San Gabriel Valley Water).
d/ Annual average reported by the Federal Reserve.
e/ Slope of -.42 = change in risk premium divided by change in bond rates.
Derived from data derived at lines 20, 21, and 22 above.
f/ Source: Table 9.

6/29/04

Arizona Water Company

Table 12

Risk Premium for Water Utilities Based on Past Earned ROEs

Panel A: Historic Data

		Earned ROE		Baa Rate		Risk Premium
1	1985	14.40%	a/	12.72%	d/	1.68%
2	1986	13.28%	a/	10.39%	d/	2.89%
3	1987	14.58%	a/	10.58%	d/	4.00%
4	1988	12.42%	a/	10.83%	d/	1.59%
5	1989	10.39%	a/	10.18%	d/	0.21%
6	1990	11.07%	a/	10.36%	d/	0.71%
7	1991	12.82%	a/	9.80%	d/	3.02%
8	1992	11.80%	b/	8.98%	d/	2.82%
9	1993	11.90%	b/	7.93%	d/	3.97%
10	1994	10.76%	b/	8.63%	d/	2.13%
11	1995	11.30%	b/	8.20%	d/	3.10%
12	1996	12.21%	b/	8.05%	d/	4.16%
13	1997	11.93%	b/	7.87%	d/	4.06%
14	1998	11.34%	b/	7.22%	d/	4.12%
15	1999	11.02%	b/	7.88%	d/	3.14%
16	2000	9.91%	b/	8.37%	d/	1.54%
17	2001	10.25%	b/	7.95%	d/	2.30%
18	2002	10.58%	c/	7.80%	d/	2.78%
19	Average 1985-1992	12.60%		10.48%		2.12%
20	Average 1993-2002	11.12%		7.99%		3.13%
21	Difference	1.48%		2.49%		-1.02%
22	Slope		0.59		-0.41	

Panel B: Solve for constant in formula (risk premium = constant - slope x Baa rate):

constant	=	risk premium	+	slope-[e/]	x	Baa rate
constant	=	3.13%	+	0.41-[e/]	x	7.99%
constant	=	6.39%				

Panel C: Solve for current risk premium and equity cost:

Risk Premium	=	constant	-	slope	x	Baa rate			
Risk premium	=	6.39%	-	.41	x	7.68%-[f/]	=		3.3%

Estimated cost of equity = bond rate + risk premium = 10.9%

Notes and Sources:

a/ Source: CPUC Staff Table 3-4, Application 95-09-010 (San Gabriel Valley Water).
b/ Source: CPUC Staff Table 2-7, Application 02-09-030 (California-American Water).
c/ Source: CPUC Staff Table 2-7, Application 02-11-044 (San Gabriel Valley Water).
d/ Annual average reported by the Federal Reserve.
e/ Slope of -.41 = change in risk premium divided by change in bond rates.
Derived from data derived at lines 20, 21, and 22 above.
f/ Source: Table 9.

6/29/04

Table of Contents

I. Introduction

Q. Please state your names and positions.

A. My name is Doug Kuns. I am the Manager of the Pricing and Tariffs Department within the Rates and Regulatory Affairs Department.

My name is Marc Cody. I am a Senior Analyst in the Pricing and Tariffs Department.

Q. Have you previously filed testimony in this proceeding?

A. Yes, our direct testimony and qualifications are provided in PGE Exhibit 1300.

Q. What is the purpose of this sursurrebuttal testimony?

A. The purpose of this sursurrebuttal testimony is to address the issues identified by the League of Oregon Cities (LOC), the City of Portland (COP), and the City of Gresham (COG), collectively referred to as the Cities. We also address the pricing issues identified by ICNU and OPUC Staff regarding Schedule 76R, Economic Replacement Power.

II. Service Restoration Issues

Q. Please summarize the service restoration modifications proposed by the Cities.

A. The Cities in Exhibit COP/COG/LOC/250 propose that PGE revise Rule C in a manner that requires PGE to perform the following:

> PGE will provide city customers with the name(s) of the individual(s) at PGE responsible for coordinating restoration for each critical account, and 24-hour contact information (cell phone or pager) for such individuals;
>
> PGE's designated representative(s) will be made accessible in a manner that will cover both planned and unplanned outages and be sufficient to cover a number of contingencies;
>
> both PGE and the cities have a continuing responsibility to notify the other if there are any changes in critical account or contact information; and
>
> PGE will meet with the League and any interested customer for the purposes of developing protocols and procedures sufficient to ensure that PGE and its city customers each can continue to meet their obligations to update and maintain the accuracy of all information required or intended to be exchanged.

The Cities propose that they have the following responsibilities to PGE:

> Municipal customers directly responsible for public safety or emergency response functions will provide PGE with lists of accounts they deem critical to public welfare and safety, and the name and 24-hour contact information (cell phone or pager or 24x7 dispatch center phone number) for city personnel assigned to each account for restoration purposes.

Q. Is PGE willing to provide the proposed services to the Cities?

A. Yes, PGE is already providing this service for a number of critical loads and is willing to expand it as necessary with the provision that the loads are truly critical. If too many loads are deemed critical, then none truly are.

Q. Have the Cities provided PGE the data for which they are responsible?

A. No.

Q. What do you recommend regarding the proposed changes to Rule C?

A. We do not believe that any changes are necessary to achieve our mutual goal of ensuring that services to critical loads are restored as quickly as possible.

III. Streetlighting Service

A. Maintenance Costs

Q. Please identify the amount by which the Cities propose to reduce PGE's proposed test period lighting services maintenance costs.

A. In their surrebuttal testimony the Cities continue to propose that PGE substantially reduce the level of proposed lighting maintenance for the 2007 test period. Because the Cities within their testimony do not specify the dollar amount by which they propose to reduce PGE's proposed lighting maintenance amount of $3.1 million, we have had to estimate the effects of their proposals. As stated in our Rebuttal testimony, we estimate that the Cities propose a $1.2 million (39%) reduction in the level of test period lighting maintenance, a figure that on a per light basis is 14% lower than the nominal level of incurred maintenance in 2002. The Cities have not contested our estimates in their surrebuttal testimony; therefore, we conclude that our estimates are similar to those of the Cities.

Q. On what basis do the Cities' premise this level of reduction in lighting services maintenance?

A. The Cities attempt to support their reductions by claiming that PGE should make the following adjustments to its Streetlight Cost Study: 1) "assume across-the-board improvements instead of selected improvements" in lighting service productivity (See COP/COG/LOC/250/9, lines 11-13); 2) PGE should alter its Streetlight Cost Study so that at all times only the least expensive crew type is assumed to perform the necessary corrective maintenance; and 3) reduce corrective repair frequencies by "40% across the board" (See COP/COG/LOC/200, page 10, line 8) based on data for only two cities for a portion of the current year and an unsupported and erroneous conclusion that the average age of PGE's streetlight system is declining.

Q. Please restate the Cities' arguments regarding the labor productivity assumptions contained in the Streetlight Cost Study.

A. The Cities in their surrebuttal testimony at COP/COG/LOC page 9, lines 9-13 state the following:

> PGE is unable to document any of its conclusions beyond the assertions already made in the company's workpapers. Therefore, PGE should be required to assume across-the–board-improvements instead of selected improvements.

Q. Why should the Cities' arguments concerning "across the board improvements" in labor productivity be rejected?

A. Within the UE 180 Streetlight Cost Study, we included labor improvements relative to the UE 115 Streetlight Cost Study in the following three categories of corrective maintenance: Emergency Starter Replacement, Emergency Luminaire Replacement, and Power Doors. These labor productivity improvements were based upon consultation with the Manager of Lighting Services who reviewed all of the prior labor input assumptions for corrective maintenance and recommended reductions in the estimated man hours for the three functions above and also verified that the other functions were reasonable estimates for use in a cost study.

Q. What evidence do the Cities provide to support their labor productivity assertions?

A. The cities in both their reply and surrebuttal testimony provide no evidence to back up their assertions. Basically they posit an unsupported hypothesis and then attempt to shift the burden to PGE to disprove instead of proving it themselves.

Q. What evidence has PGE provided regarding labor productivity?

A. PGE has provided considerable detail in its Pricing work papers that specify labor rates, productivity assumptions related to specific tasks, and the applicability of these assumptions to specific lighting options.

Q. What do you recommend regarding labor productivity assumptions within the Streetlight Cost Study?

A. We recommend that the Commission reject the Cities' arguments because they are merely statements that are not based on any analysis. PGE on the other hand has produced a detailed maintenance cost study that contains fully-updated labor productivity assumptions consistent with our experience providing lighting maintenance. We have used this experience to more accurately calculate marginal lighting maintenance costs that we use to more accurately spread the test period lighting services maintenance cost projection of $3.1 million to the various lighting options for which PGE provides maintenance.

Q. What do the Cities' propose regarding the type of crew that performs corrective maintenance?

A. The Cities assert that PGE should be required to assume that only the least costly type of crew performs all corrective lighting maintenance and that any subsequent reduction to the estimate of marginal costs from using this assumption be deducted from PGE's proposed overall level of test period lighting maintenance.

Q. Why should the Cities' assertions regarding crew dispatch be rejected?

A. PGE in its Rebuttal testimony pointed out that within the Streetlight Cost Study are assumptions that are based on historical experience regarding what type of crews perform the necessary corrective lighting maintenance. Different types of distribution maintenance crews frequently perform this lighting maintenance because they are also frequently dispatched to perform other types of distribution maintenance functions in the area. Because these crews are already in the area, they are at that point in time, the least cost resource available to perform specific maintenance tasks. To dispatch another crew to that same area solely for the purpose of performing corrective lighting maintenance would be duplicative and inefficient resulting in all else equal higher total distribution maintenance costs.

In short, our Streetlight Cost Study recognizes that corrective lighting maintenance occurs in a manner that reflects the normal distribution operations of PGE working to minimize <u>total</u> distribution costs, not just lighting services costs. We believe that this is the most realistic approach as well as the most equitable to all of our customers.

Q. What do the Cities assert regarding corrective lighting repair frequencies?

A. In their opening testimony, the Cities assert that the projected incidence of corrective repair frequencies used by PGE do not provide reasonable projections for 2007. Instead, the Cities propose that the corrective repair frequencies used in the Streetlight Cost Study "be reduced by 40 percent across the board." (COP/COG/LOC/200, page 10, line 8) They base their assertions on partial-year reported repair frequencies for only two cities, Portland and Gresham. In their surrebuttal testimony the Cities continue to claim that corrective repair frequencies should fall because the average age of PGE's streetlight system is declining. (COP/COG/LOC/250, page 8) The Cities base this claim on the fact that PGE's end-of-year plant balances for streetlight related accounts have increased from 2001 to 2006.

Q. Please demonstrate why the repair frequencies that the Cities calculate are misleading and should be rejected.

A. The Cities, based on partial-year data for only the two cities referenced above, calculate corrective repair frequencies of 10.89% annually (based on COP/COG/LOC response to

PGE Data Request No. 003). This frequency of corrective repairs when applied to PGE's test period projection of 124,193 fixtures yields an estimate of 13,525 corrective repairs. In order to evaluate if this figure was reasonable, we researched historical repair frequencies for the 1997 to 2005 period. These data are more fully presented in PGE Exhibit 2901 and are summarized in Table 1 below:

Table 1

Annual Corrective Repairs	
Year	Corrective Repairs
1997	14,645
1998	12,703
1999	15,931
2000	18,644
2001	18,415
2002	19,305
2003	22,148
2004	18,749
2005	16,145

As demonstrated in Table 1, the amount of corrective repairs can vary considerably from one year to the next. The highest figure of 22,148 incurred in 2003 exceeds the lowest figure of 12,703 incurred in 1998 by 74%. We believe that this amount of year-to-year variation supports PGE's use of multi-year averaging and clearly demonstrates the problematic nature of deriving estimates from partial-year data that is gleaned from only a subset of PGE's lighting system. Furthermore, we point out that in eight of the nine years the amount of incurred corrective maintenance exceeds the implied amount recommended by the Cities, in many cases considerably so.

Q. Please summarize the Cities' assertions regarding the average age of PGE's streetlight system.

A. In their surrebuttal testimony, the Cities argue that the average age of PGE's streetlight system has decreased because PGE's end-of-year streetlight-related plant balances have increased during the 2001 to 2006 period. The Cities conclude the following:

> Second, PGE's workpapers demonstrate that the total investment in the system has increased, even if the share of the streetlight revenue requirement associated with streetlights has fallen. See COP/COG/LOC-254. The end of year plant balance for the three FERC accounts that comprise streetlights has increased from about $37 million in 2001 to about $48.5 million in 2006 (estimated), or about 30 percent. Thus, the Cities' conclusions that the average age of the system is declining are supported by PGE's own data. Accordingly, it should not be surprising that repair frequencies should be actually failing in 2006 and projected to remain at that level in 2007.

Q. Can you demonstrate that the Cities' overall contention that maintenance activities are decreasing as investment is increasing is erroneous and should be rejected?

A. Yes. The Cities' position is based on two unproven assumptions:

1) That increasing plant balances are equivalent to declining average age; and
2) A lower average age yields lower corrective maintenance.

The Cities do not prove either assertion.

Q. Does increasing investment imply that the average age is declining?

A. No. The simple example below demonstrates this. Assume a new system in which $1 million is invested at the beginning of each year. At the end of year one, we would have $1 million invested and an average age of one year. At the end of year two, $2 million would be invested with an average age of one and a half years. After three years, $3 million would be invested with an average age of two years. Clearly, growing investment does not necessarily equal a declining average age.

Q. Would declining average age imply reduced maintenance?

A. Not necessarily. We are all familiar that some electrical equipment goes through a "burn-in" period because of initial failure issues. The Cities provide no evidence supporting their hypothesis that a declining average age would yield lower maintenance frequencies.

Q. Is there another fallacy in the Cities' argument?

A. Yes. Approximately 74% of the streetlights maintained by PGE are customer owned. The investment numbers cited by the Cities do not include the costs of these customer-owned streetlights and thus are not representative of the system that PGE maintains.

Q. What do you recommend regarding the Cities' assertions about corrective repair frequencies?

A. We continue to support our method of estimating corrective repair frequency within the Streetlight Cost Study. Given the year-to-year volatility of the corrective repairs, it is clearly preferable to average these repairs over several years instead of using the limited data advocated by the Cities (six or seven month's data for only two cities). Additionally, because the Cities incorrectly use historical plant investment as a barometer of the age of PGE's streetlight system, they have not provided any evidence that the average age of PGE's streetlight system is declining nor that such a system requires less corrective maintenance.

Q. Please state why PGE's test period projection of maintenance for lighting services is the best estimate and should be adopted by the Commission.

A. The projected lighting maintenance expense is developed from detailed budgeting that documents year-to-year cost changes by cost element and activity. This budgeting process is the same process we use to establish the overall test period distribution maintenance expense, a component of PGE's test period revenue requirement. As we discussed in our

Rebuttal testimony, we use the Streetlight Cost Study to develop per unit cost estimates that help us to send the correct price signal to lighting customers for whom PGE provides maintenance. This is the same process we follow when we estimate functional marginal cost revenues and reconcile them to functional revenue requirement. We have additionally shown in our Rebuttal testimony that our projection of test period lighting maintenance is consistent with recently incurred values.

Above we have demonstrated that the Cities' proposed adjustments to the Streetlight Cost Study are both unsupported and sometimes erroneous and should be rejected. Proposed adjustments should result in levels of maintenance that have some connection to recently incurred costs; we have demonstrated that the Cities' unsupported assertions do not have this connection.

B. Additional Streetlight Issues

Q. Please provide a summary of the additional Streetlighting issues raised by the Cities in their surrebuttal testimony.

A. The Cities raise the following issues: 1) the Cities propose to be able to switch their current Option B lights for which PGE provides maintenance to Option C lights for which the respective municipality provides maintenance; 2) the Cities argue that PGE should reduce the lighting operating hours assumption from the current level of 4,150 hours per year to 3,995 hours per year (the Cities further argue that PGE perform an unspecified field study with the Cities in order to determine a better estimate of operating hours); 3) the Cities continue to oppose PGE's proposal to meter new Option C lighting installations; and 4) regarding the circuit charge, the Cities in their opening testimony propose that PGE track and account for each individual dedicated streetlight circuit within its service territory and determine if each individual streetlight is or is not served by a dedicated circuit. Their surrebuttal testimony seems to indicate that they continue to question the circuit charge, but they propose no specific adjustment. The Cities additionally assert that PGE should conduct a field audit of dedicated streetlight circuits and also that PGE should hire a third party to provide a cost estimate of modifying PGE's accounting and billing systems to accomplish the tracking, accounting, and billing referenced above.

Q. Please state PGE's position on allowing the Cities to convert their Option B lights that are attached to PGE distribution poles to Option C lights.

A. As we stated in our Rebuttal testimony, we believe that for safety and reliability reasons, PGE should perform the maintenance to lighting fixtures attached to PGE distribution poles. We do not restate our arguments here, but rather we point out what we believe are a minimum set of requirements that the Commission must consider if it decides to allow a municipality to perform maintenance on equipment attached to PGE poles. These minimum requirements are as follows:

1) The municipality must convert all current Option B luminaires to Option C luminaires at one time and must provide sufficient notice to PGE to allow it to manage its workforce and modify its records. Additionally, all new luminaires within the municipality must be either an Option C or an Option A luminaire. As Option C luminaires, PGE will not be obligated to provide any maintenance of them. The municipality must notify its residents that streetlight maintenance/repair issues are to be directed to the municipality and not PGE.

2) All personnel or contractors employed by the municipality to maintain the streetlights on Company-owned poles must be qualified to perform the services in a manner consistent with applicable codes and safety requirements.

    a. Qualified workers must perform the work in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC. A "Qualified Worker" means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a "qualified person" or "qualified employee" with regard to the work in question as described in CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker will be a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

b. To the extent permitted by the Oregon Constitution and the Oregon Tort Claims Act, the municipality shall hold PGE harmless and indemnify it for any personal injury, property damage or damage to PGE's electrical system that is caused by the acts or omissions of anyone that performs streetlight maintenance for the municipality on PGE-owned poles. PGE shall be named an additional insured on applicable insurance policies of contractors used by the municipality to perform the work.

3) The municipality and PGE must develop appropriate procedures to maintain accurate records of streetlight and pole ownership, lamp wattages, communications protocols with PGE, and related information necessary for accounting, billing and mapping purposes.

4) The OPUC must affirm that any service disturbance caused or any violation of OPUC safety rules by the municipality or an agent of the municipality working on streetlights will not be counted against PGE as a service quality incident for purposes of Service Quality measurements.

5) If in the future, the municipality seeks to convert Option C luminaires on PGE-owned poles back to Option Bs, and if the Option B service is available, the municipality must convert all such luminaires to Option B. Prior to re-conversion PGE will, at the municipality's cost, determine if the luminaires have been maintained in an acceptable manner and maintenance has not been deferred. If the luminaires have not been properly maintained, PGE will charge the municipality the cost of any corrective maintenance required to bring the

luminaires up to PGE standards. Prior to re-conversion the municipality must provide sufficient notice to PGE to allow it to manage its workforce and modify its records.

Q. Please state why the streetlight operating hour analysis PGE presented in Rebuttal testimony is superior to the analyses presented by the Cities.

A. The Cities continue to contend that PGE should be required to reduce the annual hours of operation for streetlight luminaires from the current 4,150 to 3,995. Their basis for this assertion is an analysis they presented in their opening testimony and the fact that PacifiCorp uses an assumption of 3,931 operating hours for their Oregon service territory. As we pointed out in our Rebuttal testimony, it is not sufficient to change the operating hours assumption simply because another utility uses a different assumption. We further pointed out that PGE could just as easily have proposed adopting Puget Sound Energy's assumed operating hours of 4,200 operating hours. However contrary to the Cities' assertion that PGE has offered Puget Sound Energy as an alternative source of operating hours (See COP/COG/LOC/250, page 11, lines 10-13), we prepared an analysis based upon professional sources such as photocontrol manufacturers, and lighting experts such as the Illuminating Engineering Society of North America (IESNA.) In our Rebuttal testimony, we relied upon these sources as well as the U.S. Naval Observatory and the Western Regional Climate Center to establish an annual operating hour assumption of 4,176 hours. In surrebuttal testimony, the Cities' only criticism of this detailed study was that PGE should substitute an IESNA recommendation of adding 50 hours for dayburners with 50 hours for outages, resulting in a decrement of 100 hours to PGE's calculated 4,176. As we did in our Rebuttal testimony, we point out this outage assumption was contained in the 1984 stipulation between the City of Portland and PGE which established the current operating hours assumption of 4,150. We believe that it is disingenuous to propose abandoning a prior stipulation's results and proposing to keep only the portion that provides benefits. We therefore urge rejection of the Cities' 50-hour reduction for outages.

Q. Please restate the critical shortcomings in the Cities' operating hours analysis.

A. The Cities shortcomings are as follows:

- The Cities failed to provide any documentation regarding their assumption that all streetlights go on 22 minutes after sunset and off 19 minutes before sunrise. When we asked the Cities for this they failed to provide the photocontrol manufacturer's specifications as well as the 1961 journal article they claimed to reference. (PGE Exhibit 2203, page 7)
- The Cities failed to consider atmospheric considerations such as the number of cloudy days, haze, or smog.
- The Cities did not include any allowance for trees or buildings that may affect photocontrol operation.

Q. Are there other factors beyond what you presented in your Rebuttal testimony that are specifically documented by IESNA as contributing to streetlight operating hours?

A. Yes. As mentioned in the IESNA document referenced above (PGE Exhibit 2202), many photocontrols will drift over time resulting in lights turning on earlier and off later. IESNA estimates that this photocontrol drift will result in an additional 30 hours per year of operating hours (PGE Exhibit 2202, page 17).

Q. What is the operating hours result if you include both the photocontrol drift addition advocated by IESNA and the Cities' outage assumptions?

A. If we add the 30 hours for photocontrol drift and subtract the Cities' recommendation of 50 hours for outages to our calculated figure of 4,176 hours, the result is 4,156 operating hours, a figure that is almost identical to the current 4,150 hours.

Q. Does the IESNA document provide further guidance in estimating streetlight operating hours?

A. Yes. In section 4.2.3.6, page 15 IESNA states the following:

> **Approximation.** Small lighting systems may use an approximation of 11.5 hours of average burning time per day or 11.5x 365.25 = 4200 hours per year.

Q. What do you recommend regarding streetlight operating hours?

A. We recommend retaining the current operating hour assumption of 4,150 hours. Our analysis is supported by data provided by lighting professionals and by a large photocontrol manufacturer. The Cities continue to advocate an analysis for which they have not provided sufficient documentation for their various assumptions, and for which they do not include any factors such as atmospheric conditions or photocontrol drift that according to IESNA contribute to increases in operating hours.

Regarding the joint study proposed by the Cities, PGE is willing to discuss this matter with the Cities when the Cities have more fully developed a specific proposal. PGE is unwilling to enter into an arrangement that may provide little useful information at potentially great cost. Furthermore, PGE believes that the information provided by the professionals at IESNA and photocontrol manufacturers obviates the need for potentially expensive field testing.

Q. Has PGE modified its position regarding the metering of new Option C installations?

A. Yes. PGE withdraws its proposal to meter new Option C installations. Instead PGE will identify problematic instances of energy diversion related to Option C circuits and work with the municipality or other government agency to resolve the problem. Resolving the individual problematic situation may or may not include metering the problematic lighting installation.

Q. Please discuss the specific circuit charge proposals advanced by the Cities in their surrebuttal testimony.

A. At COP/COG/LOC/ 250, page 18, lines 9-25, the Cities propose the following:

> The Commission should require PGE to conduct an audit of a sample of the lights that are assessed the circuit charge, in cooperation with the Cities. The purpose of this audit would be to determine how many lights are being served with a PGE-owned circuit and how many do not require a PGE-owned circuit. The results of this audit should be reported to the Commission no later than March 1, 2007. Second, the Commission should require PGE to develop an independent estimate of the cost required to modify the accounting and billing systems so that streetlight customers are only charged for the circuits that are actually being used. By "independent party" we mean a neutral third party hired by PGE. The Cities and the Commission Staff should be consulted in the selection of the third party. This cost estimate should also be reported to the Commission no later than March 1, 2007. Once the information is developed and made public, the Cities (and PGE and the Commission) will be better able to determine the best course of action.

Q. Please demonstrate why the Cities' proposal to conduct a field audit of streetlight circuits and to hire a third party to suggest how to modify PGE's Accounting and Billing system is unnecessary and produces no benefits.

A. As we explained in our Rebuttal testimony, the streetlight circuit issue is akin to tracking the length of service laterals for residential customers. We do not charge a residential customer more if the length of his or her service lateral is greater than that of another residential customer. Instead, we set rates for all residential customers on a basis that considers the average length and cost of the service lateral. This enables large cost efficiencies in billing and is an equitable approach to rate making. If we attempted to bill our 700,000 residential customers based on their unique attributes such as length of service lateral, we would incur tremendous cost increases in both customer service and accounting. We believe that the same principles apply in the case of streetlights. We bill all applicable lighting customers the average cost of providing dedicated lighting circuits, not individual charges for the more than 124,000 lights to which the circuit charge is applied.

Regarding the streetlight circuit audit and the "independent" estimate of how to change PGE's accounting and billing, we point out that the Cities have not stated how the results of such a process would be used. For example, do the Cities contest the overall level of circuit charge or just how the circuit charge is distributed to individual customers? Do the Cities wish to use the field audit in order to have the circuit charges differentiated by each city, county, state, or other public agency, or do they wish for separate billing for each individual streetlight? Are the Cities willing to pay for what may be an expensive evaluation of PGE's accounting and billing system? Their testimony does not provide answers to these questions. In short, we fail to see the value that potentially expensive audits and evaluations may provide. We, therefore recommend, that the Commission reject these proposals advanced by the Cities.

IV. Partial Requirements

Q. Please state ICNU's proposals regarding Schedule 76R Economic Replacement Power.

A. In both their Reply and Surrebuttal testimony, ICNU proposes that PGE be required to replace the current pricing for Schedule 76R Economic Replacement Power with the following three pricing options: (ICNU/206 page 1, lines 16-23)

1) substitute the daily-market pricing option under proposed Schedules 83/89 for the hourly market pricing provisions on 76R;

2) allow partial-requirements customers to use direct access service to purchase economic replacement power in the same manner as the buy-through arrangements in Schedule 576R are treated; and

3) allow Schedule 76R customers to purchase Schedule 87, Experimental Real Time Pricing Service economic replacement power, subject to the provisions of that experimental tariff, which impose limitations on size and the number of customers.

Q. How does Staff view the proposals of ICNU?

A. Staff states that they are generally supportive of ICNU's proposals for Economic Replacement Power (ERP). Staff also discusses extensively the economic replacement power options that PacifiCorp makes available to partial requirements customers (Staff/1700 Schwartz, pages 3 and 4). Based on this extensive discussion, we believe that Staff is supportive of PGE replacing its current after-the-fact hourly pricing with ERP options similar to those provided by PacifiCorp.

Staff states that they are "intrigued" by the ICNU proposal of allowing partial requirements customers to participate in Schedule 87 because no full requirements customers have enrolled in the pilot program (Staff/1700 page 6, lines 3-6).

Staff also states that ICNU's second proposal of allowing a partial requirements customer to purchase their baseline energy requirements through PGE's Schedule 75 and then purchase their economic replacement power from an ESS should be "more fully explored as an alternative."

Q. How do you propose to resolve the issue of pricing options for Schedule 76R Economic Replacement Power?

A. We propose to resolve this issue by replacing our current ERP after-the-fact hourly pricing with ERP supply options offered under PacifiCorp's Schedule 276 (with minor modifications). Our Schedule 76R would include charges and adjustments for losses and related provisions as contained in our current Schedule 76R. We also propose to replace the quarterly pricing option with an option that allows for an ERP supply term greater than a month with a mutually agreed-to-price. Based on our understanding of Staff's Surrebuttal testimony, we believe that our proposal should be acceptable to Staff. Furthermore, we also believe that adopting this methodology satisfies what ICNU has identified as most important for a partial requirements customer – "to obtain price certainty". (See ICNU/206, page 5, lines 8and 9).

Q. Please explain why you do not support ICNU's second proposal, to allow a partial requirements customer to purchase ERP from an ESS while purchasing baseline energy from PGE.

A. We do not recommend requiring that PGE add another ERP service supply option. The ESS service option has and will continue to be available in conjunction with Schedule 575. Furthermore, our proposed ERP options described above give partial requirements customers a market supply option containing the features that ICNU desires for ERP service.

We are concerned about ICNU's suggestion that their proposal is analogous to the PGE Split Load option. We believe this analogy is inaccurate. The Split Load option available to proposed Schedule 89 requires a commitment of one year of service with minimum loads of 10 MWa and a 60% load factor. Because ICNU has not mentioned these particular requirements within their testimony, we believe that they do not wish to have these requirements applied to ERP.

Q. Please state your concerns regarding ICNU's third proposal, to allow partial Schedule 76R customers to receive service under the provisions of Schedule 87, Experimental Real Time Pricing (RTP).

A. We have two concerns regarding this proposal. First, both Staff and ICNU use the term "partial requirements customer" and "Schedule 76R customer" interchangeably when referring to Schedule 87. We are therefore unsure if Staff and ICNU propose that all of the partial requirements customers' load be eligible for Schedule 87 or if they propose that only the economic replacement power portion (Schedule 76R) be eligible. We believe that they mean the latter, but at certain points within their testimony the distinction is unclear to us (for example Staff/1700 page 6 lines 3 through 12 refer to partial requirements customer and Baseline Demand under Schedule 75 in a manner that could be construed to mean the former). We point out that the issues concerning Schedule 75 were resolved in the Rate Design Stipulation filed with the Commission October 4. Second, as we discussed in our

Rebuttal testimony, when we proposed Schedule 87 using day-ahead synthetic prices, we certainly did not contemplate a partial requirements customer that could change its hourly energy needs by as much as 50 megawatts from hour to hour. We currently have a 3 mills/kWh adder to cover the risk that the actual energy price in an hour may higher than the price that PGE synthesizes from the previous day's hourly prices. However, we have no way of knowing if this adder is sufficient to price the risk of a customer who may ramp its on-site generation in a manner such that its energy requirements change by significant amounts from hour to hour.

Q. What do you conclude regarding the ERP pricing options made available to partial requirements customers?

A. We conclude that the enhanced pricing proposals we make in this sursurrebuttal testimony should be adopted by the Commission and that those presented by ICNU should be rejected. We believe that the proposal we have made addresses the most important issues identified by ICNU and Staff and represents a reasonable settlement of the issues.

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2901	Historical Corrective Repair Frequencies

PORTLAND GENERAL ELECTRIC
Historical Repair Frequencies

PRIMARY REPAIR CODE	DESCRIPTION	1997	1998	1999	2000	2001	2002	2003	2004	2005
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AB	LAMPS	**7,440**	**6,490**	**9,791**	**8,533**	**8,772**	**9,006**	**10,256**	**8,562**	**7,262**
BB	PHOTO-CONTROLS	**4,045**	**3,543**	**4,046**	**6,129**	**5,909**	**6,351**	**7,428**	**6,465**	**5,615**
CA	STARTERs (HPS Only)	**707**	**484**	**469**	**552**	**324**	**740**	**827**	**699**	**744**
EA	REFRACTORS	**53**	**71**	**96**	**95**	**56**	**83**	**90**	**68**	**72**
FA	CIRCUITS	**659**	**415**	**468**	**1,156**	**984**	**1,191**	**1,451**	**1,102**	**993**
LC/HR	LUMINAIRE REPLACEMENT	**569**	**777**	**248**	**758**	**808**	**945**	**1,174**	**994**	**937**
OTH	OTHER - NOT DEFINED	**997**	**748**	**638**	**1,335**	**1,475**	**926**	**798**	**785**	**449**
PD	POWER DOOR REPLACEMENT	**175**	**175**	**175**	**86**	**87**	**63**	**124**	**74**	**73**
		========	========	========	========	========	========	========	========	========
		14,645	12,703	15,931	18,644	18,415	19,305	22,148	18,749	16,145

Q. Please state your name and qualifications.

A. My name is Bruce Carpenter. I am General Manager of Revenue Operations. My qualifications appear in Section V of UE 180/PGE Exhibit 800.

My name is L. Alex Tooman. I am a project manager in Regulatory Affairs. My qualifications appear in Section XI of UE 180/PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to notify the Commission and other parties that PGE withdraws its request for a ruling on advanced metering infrastructure (AMI) in the UE 180 rate case.

Q. What type of decision was PGE requesting in the UE 180 rate case?

A. PGE initially requested that the Commission find the decision to proceed with deployment of an AMI system to be reasonable and prudent at this time. PGE also asked for Commission approval of the ratemaking treatment it proposed for AMI-related costs. This proposal included a deferral of the revenue requirement for capital costs and O&M savings resulting from AMI installation. PGE later clarified its request to entail Commission "acknowledgement" of the AMI proposal. We explained that this acknowledgement was expected to be similar to those we receive for generating plants as part of our integrated resource planning process.

Q. How do you respond to CUB's concerns regarding the nature of this acknowledgement?

A. Because PGE is effectively de-linking AMI from the rate case and we are no longer requesting any form of Commission approval or acknowledgement in that context, we believe this is a moot point and see no need to discuss the issue further. PGE will submit

AMI in a subsequent non-rate case proceeding, which will determine the type of Commission decision applicable to the AMI proposal.

Q. How specifically is PGE de-linking AMI from the rate case?

A. PGE's 2007 test year revenue requirement does not, nor will it, include any aspect of the proposed AMI system. Further, we ask that no decision be made by the Commission regarding AMI in UE 180.

Q. What does PGE plan to file to establish a new proceeding for AMI?

A. PGE plans to submit its AMI proposal in a subsequent non-rate case proceeding. This will most likely entail the following applications but can be modified based on discussions with other parties or as other information becomes available:

- A supplemental tariff filing for the proposed accelerated write-off of non-AMI meters, with termination if full deployment is not implemented.
- A deferral application for the revenue requirement of the AMI system less O&M savings throughout the deployment period.

These applications will be supported by PGE's current financial analysis and a scoping plan for secondary benefits not covered in PGE's financial analysis. PGE will also submit detailed implementation plans for the primary benefits identified in the financial analysis.

Q. How do you plan to utilize the information already generated with respect to AMI in UE 180?

A. Upon agreement from other parties, PGE proposes that all relevant evidence and information provided in UE 180 be carried forward to the future proceeding(s) to avoid repetition and delay. Because of this, we also suggest that there is no reason to submit briefs regarding AMI in UE 180.

Q. Do you have any response to the other issues CUB raised in its surrebuttal testimony?

A. PGE respectfully acknowledges CUB's concerns and we have prepared responses to each of them accordingly. Because we are de-linking AMI from the UE 180 rate case, however, we do not believe it is appropriate to continue the discussion in this forum. Instead we will address them in a future proceeding.

Q. Does this conclude your testimony?

A. Yes.