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I. Introduction

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

A. My name is James J. Piro. I am the Executive Vice President, Finance, Chief Financial Officer and Treasurer at Portland General Electric (PGE). My qualifications appear in PGE Exhibit 100, Section VI.

My name is Robert Tamlyn. I am the Director of PGE's Tax Department. My qualifications appear in Section VI of our testimony.

Q. What is the purpose of your testimony?

A. Our testimony rebuts Mr. Jubb's claims as the City of Portland's witness in their Exhibit 100.

Q. Could you summarize your rebuttal testimony?

A. Yes. Our testimony addresses the following issues: 1) the impact of Senate Bill 408 (SB 408) on utility tax planning, 2) deemed PGE limited liability company (LLC) conversion, and 3) "ratepayer" credits for taxes paid to Enron. First, our testimony describes PGE's incentives to engage in prudent and practical tax planning. Section II demonstrates that Mr. Jubb is incorrect when he suggests SB 408 changed utility tax-planning incentives, and refutes the suggestion that the law requires a wholesale revision of standard accounting practices. COP/100, Jubb 4-5, 10-11. It points out Mr. Jubb's significant misunderstanding of SB 408 that underlies his improper suggestion that the Public Utility Commission of Oregon (Commission) order refunds to customers for deferred income taxes that accumulated prior to the passage of SB 408.

Section III of our testimony demonstrates a number of reasons why it would have been imprudent and not feasible for PGE to have undertaken the LLC conversion scheme proposed by Mr. Jubb. Specifically, Section IV shows how Mr. Jubb's proposal would not necessarily have saved customers any money and could have subjected PGE to substantial interest and tax penalties. Finally, Section V notes that Mr. Jubb provides no legal basis for his claim that the Commission should authorize credits to customers for payments PGE made to Enron based on the Tax Allocation Agreement between the companies.

II. Senate Bill 408

Q. What is SB 408?

A. SB 408 is a law that changes the way income taxes are treated for ratemaking purposes, in that taxes are now subject to an annual automatic adjustment clause and an annual true-up. In simplest terms, SB 408 attempts to compare income taxes collected from customers and taxes actually paid to units of government. To the extent that PGE collects more/less in taxes from customers than the corporation or holding company (properly attributed) pays to the government, this law requires the utility to put into place an automatic adjustment clause to refund/collect this amount to/from customers.

Q. Are there final rules currently in place to implement this new legislation?

A. No. PGE has participated for more than a year in AR 499, the docket in which those rules are being developed. The public comment period in AR 499 has ended, and PGE is currently awaiting a final order issuing the permanent rules. At this time, a number of significant questions remain about how SB 408 will work and what its effect will be on the way taxes are treated in the ratemaking process.

Q. Is Mr. Jubb correct in claiming that SB 408 changed PGE's incentives to engage in prudent and practical tax planning?

A. No. It is difficult to follow Mr. Jubb's assertions with regard to SB 408. On one hand, he suggests that prior to SB 408, utilities had an incentive to avoid income taxes because the money the company saved would flow through to the company in the form of additional income. Yet on the other hand, he argues that PGE did not engage in prudent tax planning in the past, even when it had a financial incentive to do so.

Q. Can you explain what PGE's actual incentives are to engage in prudent and practical tax planning?

A. Yes. SB 408 did not change PGE's basic incentive with regard to tax planning. Like all businesses, PGE seeks to minimize, within the boundaries of all applicable rules and regulations, our income tax expense in order to lower customer prices, obey regulations, and make prudent business decisions.

Q. Can you provide examples of how PGE has worked in the past to engage in prudent tax planning with the sole purpose of lowering customer prices?

A. Yes. An example is PGE's effort to qualify for the tax credits associated with the Independent Spent Fuel Storage Installation (ISFSI) at the Trojan Nuclear Plant. PGE sought these credits on an independent basis with the sole purpose of returning the value of the credits to its customers. See Docket UM 1186. Also, PGE is in the initial stages of developing a wind power electric generation facility, which may qualify for significant tax credits. PGE is currently lobbying for an extension of the renewable electricity production tax credit, the benefits of which will reduce the cost of this project for customers.

Q. Does SB 408 create an incentive to "game the system" as Mr. Jubb suggests?

A. No. Mr. Jubb asserts that due to SB 408, PGE may now have an incentive to "game the system" by creating more taxable income in one year and rolling corresponding deductions to a subsequent year. Mr. Jubb's reasoning is not logical. Increasing taxable income in one year will cause PGE to pay more in taxes that year, even if it refunds less to customers under SB 408 rules. According to Mr. Jubb's logic, PGE has an incentive to pay more money to the government to avoid paying money to customers—this makes no sense. PGE has no incentive to act in this manner. Moreover, by shifting a deduction from one year to the next, PGE loses the time-value of those dollars for a year, and only postpones the corresponding payment to customers to the following year. In short, an incentive to "game the system" does not exist because no benefit accrues to PGE in doing so. Besides, tax rules prevent the type of activity Mr. Jubb suggests. For example, Internal Revenue Code §451 addresses the year income is reported and §461 addresses the year in which tax deductions may be claimed. The suggestion that PGE would violate tax law in order to "game" the SB 408 system is unfounded.

Q. How does Mr. Jubb propose to resolve the incentive problem he believes has been created by SB 408?

A. Mr. Jubb proposes that PGE, and only PGE to the best of our knowledge, file a regular report on tax planning with the Commission "as part of the true up those 'prudent and practical' tax-planning techniques it has employed to reasonably avoid paying income taxes." (COP/100 Jubb 5/ lines 6-7) Without any explanation, Mr. Jubb asserts that these reports will "help avoid erratic swings." *Id.*

Q. Do you believe a report to the Commission, as Mr. Jubb suggests, would resolve the purported incentive problem Mr. Jubb believes exists?

A. No. First, as stated above, we disagree with Mr. Jubb's conclusion that PGE lacks an incentive to engage in prudent tax planning. Second, SB 408 already requires PGE to file an annual tax report with the Commission on October 15 of each year. The contents of that tax report were discussed in the AR 499 proceedings. If Mr. Jubb believes SB 408 creates mixed incentives for utilities that could be resolved by requiring an annual report on tax planning, he should have raised that issue during the AR 499 discussions, to which the City of Portland was a party. This issue is not properly raised in this rate proceeding. Third, we question why Mr. Jubb has made this proposal only with regard to PGE. If the COP is concerned about SB 408, it should be making its recommendations with regard to all utilities. And finally, we note that Mr. Jubb has provided no evidence to suggest that such a filing is necessary. Mr. Jubb has not provided any evidence that PGE has failed in the past to engage in prudent and practical tax planning, or would fail to do so in the future.

III. Deemed LLC Conversion

Q. Can you briefly explain what Mr. Jubb's LLC conversion scheme would have entailed?

A. Mr. Jubb refers to a circular transaction in which PGE would begin as a corporation and for tax purposes end as a corporation. This "LLC conversion" would have been undertaken for the sole purpose of avoiding taxes.

In Mr. Jubb's scheme, PGE would first have been liquidated as a corporation, and become a "disregarded entity" for tax purposes, with assets held by Enron. At a minimum, this liquidation step would have required:

- approval by the Federal Bankruptcy Court;
- agreement by preferred shareholders to redeem all shares in PGE; and
- legal review of PGE's existing contracts and debt instruments, particularly power sales agreements and PGE's indenture, to ensure they permitted liquidation and reincorporation in a different form.

Enron would then have elected to have the former PGE treated as an LLC ("PGE LLC"), and would have distributed ownership shares in the new PGE LLC to creditors. At various times, PGE would likely have had to obtain approval from a number of bodies, including Enron, the Enron Creditors' Committee, the IRS, the Commission, the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission, the Oregon Energy Facility Siting Council, and possibly others.

Mr. Jubb asserts that this scheme would have ultimately allowed PGE LLC to step-up the basis in its assets to fair market value for tax purposes, but apparently not for ratemaking purposes, inflating the tax depreciation deductions on those same assets. After all of these steps, PGE LLC would essentially have been reincorporated for tax purposes and subject to regular corporate income taxes.

Q. Did the City of Portland (COP) propose a conversion to an LLC in the UF 4218/UM 1206 proceedings?

A. No. Mr. Jubb states in his testimony he proposed the LLC scheme in March 2006 – <u>after</u> the Commission had issued its order in UF 4218/UM 1206 and less than 30 days before the scheduled distribution of PGE stock.

Q. Do you agree with Mr. Jubb that an LLC conversion scheme would have been a prudent and practical tax measure PGE might have undertaken, and that such a measure would have resulted in credits to customers?

A. We strongly disagree with Mr. Jubb's conclusions, for a number of reasons. First, after considering significant errors in Mr. Jubb's financial calculations, we believe that an LLC conversion may generate little, if any, net savings for customers. Second, we believe engaging in an LLC conversion scheme for no business purpose other than to avoid income tax payments would have violated the step-transaction and economic substance doctrines, which would potentially leave PGE and its customers subject to penalties, accrued back taxes and interest. Finally, we believe Mr. Jubb ignored a number of significant issues that would have made it imprudent and impractical for PGE to have attempted to undertake the type of transaction Mr. Jubb describes.

A. Financial Impact of LLC Conversion Scheme

Q. Do you agree with Mr. Jubb's conclusion that an LLC conversion scheme would yield $50 million in tax savings for PGE's customers?

A. No. In fact, based on a number of significant errors in Mr. Jubb's calculations, we cannot be certain that an LLC conversion would have resulted in any tax savings for customers.

Q. Can you describe the errors Mr. Jubb made in calculating the financial impact of an LLC conversion scheme?

A. First, Mr. Jubb bases his fair market value on the initial trading price of PGE stock as of the April 3, 2006, distribution date. However, as we understand Mr. Jubb's LLC conversion scheme, PGE LLC membership shares would not be registered at the time of distribution. However, we are advised by counsel that PGE shares must be registered before distribution. If Mr. Jubb were correct, the membership shares could have been subject to significant discount in comparison to the PGE common stock. Hence, Mr. Jubb's $1.7 billion step-up is likely well overstated.

Mr. Jubb makes another glaring error in his analysis when he states that PGE's "tax basis book value" (sic) is "approximately zero" (COP/100, Jubb/8). It is unclear from where Mr. Jubb derived this zero amount and he provides no explanation. Actually, PGE's tax basis in plant is approximately $1.2 billion. Its tax basis of net assets is approximately $500 million. Mr. Jubb also fails to account for the financial impact to customers that would result from the loss of accumulated deferred taxes.

Q. Do PGE's customers benefit from accelerated depreciation and deferred taxes?

A. Yes. If there were no accelerated depreciation, PGE customers would have customer prices set on a "normal" tax depreciation basis. With accelerated depreciation, customer prices are set on a "normal" tax depreciation basis but, in addition, customers receive a deduction from rate base for the deferred tax balance. This deduction from rate base currently reduces customer prices for PGE customers by approximately $25 million per year.

Q. What would have happened to PGE's existing deferred taxes if it had undertaken an LLC conversion?

A. We believe PGE's existing deferred tax liabilities may have been eliminated if it had undertaken an LLC conversion, resulting in significant harm to PGE's customers. This is one of the primary reasons we believe it would not have been prudent for PGE to have undertaken an LLC conversion.

Q. How would PGE customers be harmed by the elimination of PGE's existing deferred tax liabilities?

A. If PGE's existing deferred tax liabilities were eliminated, the deduction from rate base would also be eliminated, which would increase PGE's rate base by about $200 million. Mr. Jubb neglects to mention that this increase to rate base would increase customer prices by approximately $25 million per year. This oversight plus his errors when calculating the potential step-up could eliminate the entirety of the savings that Mr. Jubb claims.

Q. Does Mr. Jubb address this loss of deferred tax liabilities to offset rate base in his testimony?

A. Not directly. He does state that the increase in asset rate base would be treated as an "acquisition premium" (COP/100, Jubb/9) and cites the Scottish Power acquisition of PacifiCorp and Enron purchase of PGE. Since the transaction he proposes is not an acquisition, we do not see the relevance of these citations. He lists no other LLC conversions as support for his conclusion.

Q. Mr. Jubb has indicated that if his LLC conversion scheme were undertaken, the PGE tax rate would be zero (COP/100, page 10, lines 6 and 7). Is this accurate?

A. No. Mr. Jubb stated that PGE LLC would be reincorporated for tax purposes under his scheme, and therefore would be subject to regular corporate income taxes. He provides no evidence or computations to support this statement.

Q. What other concerns do you have about Mr. Jubb's calculation?

A. Mr. Jubb calculates fair market value by looking at the stock value at the date of distribution, and assigning 100% of this value to depreciable assets. This is a gross oversimplification. An extensive, detailed allocation would have to be made and value assigned to all of PGE's assets, many of which would not be subject to depreciation (land, software, etc.). Also, Mr. Jubb has failed to consider the administrative and legal costs for doing an LLC conversion and tax reincorporation, as well as any real estate or transfer taxes. These additional costs would only make the scheme more costly for PGE's customers.

B. Violation of Tax Judicial Doctrines

Q. Can you explain the law or judicial doctrine that prohibits corporations from engaging in "step-transactions" with the sole purpose of avoiding tax liabilities?

A. Yes. The step transaction doctrine is a judicial doctrine that the IRS has successfully used to thwart attempts by taxpayers to "game the system" by using a series of steps to accomplish indirectly what they could not do directly. The IRS typically demonstrates to the courts that by collapsing a series of steps, the true goal of the taxpayer is uncovered-receiving a tax benefit that the taxpayer could not have achieved by following the substance, rather than the formality, of the law.

Q. Mr. Jubb states that a separate business purpose is not required for a liquidation under IRC §332. Does this statement fully address this issue?

A. No. While it is true that a separate business purpose may not be necessary for a liquidation under §332, the fact that a transaction is solely motivated by tax avoidance is a relevant factor in applying the step transaction/substance over form doctrines. Mr. Jubb describes his strategy as either a simple "check-the-box" or a "check and sell" strategy. Actually, the scheme he proposes is much more complicated, as we previously described. The LLC conversion he proposes includes: liquidation, followed by a "check-the-box" election, followed by a distribution of LLC shares, followed by the tax reincorporation of PGE. PGE would start out as a corporation and after all the dust settles again be taxed as a corporation, all for the sole purpose of creating a larger depreciation tax deduction. Mr. Jubb admits that this entire transaction (even though broken out in a series of steps) is motivated solely to avoid income taxes. It is unreasonable to assume the IRS would not apply the step transaction or substance-over-form doctrines, which may subject PGE to payment of back taxes, interest and penalties.

Q. Did Mr. Jubb provide any evidence of a similar LLC conversion transaction reviewed and approved by the IRS?

A. No.

Q. Can the Commission rely on the case of General Motors and General Motors Acceptance Corporation (GMAC), as cited by Mr. Jubb, as evidence that the IRS would approve of an LLC conversion for the sole purpose of tax avoidance?

A. No, we do not believe it would be prudent or practical to rely on this transaction in such a manner. Notably, we have seen no evidence that the IRS has even reviewed this transaction because it has not closed yet. In addition, after reviewing the sales agreement in question, we found that General Motors is not selling a 100% interest to the buyer. General Motors will retain a significant interest in the firm, therefore the LLC conversion does retain a *business purpose,* and Mr. Jubb's proposal does not.

C. Other Issues

Q. Could PGE have changed the corporate status without the consent of its parent corporation?

A. No. Enron, as the parent corporation, would have had ultimate approval of any change in corporate status. Mr. Jubb spends a portion of his testimony explaining how, in hindsight, this could have been accomplished using net operating losses at Enron (COP/100, Jubb/7). Mr. Jubb provides no evidence that Enron's net operating losses are or were available to offset the tax liability generated by this scheme or if Enron would donate them at no cost. Mr. Jubb appears to assume that Enron and its creditors would have been neutral to this transaction because of the existence of net operating losses. This is an undocumented assumption; in fact, no one knows at this point whether Enron will utilize some or all of its existing net operating losses.

Q. Would approval by the Enron Creditor Committee have been easy to secure?

A. We find it highly unlikely that the creditors would have approved an LLC conversion. If the membership shares were not registered, the LLC conversion scheme would have subjected creditors to diminished value because they would have traded in a less liquid market than PGE common stock. If immediately listed on a stock exchange, PGE LLC would be taxed as a corporation per Section 7704 and the IRS would not have allowed <u>any</u> step-up in value. The Enron Board is duty bound to obtain maximum economic recovery for the benefit of the creditors. They would certainly view this LLC scheme in that light.

Q. Can you explain the issue you raised surrounding the elimination of preferred stock?

A. This is an issue Mr. Jubb does not address at all, but is a prerequisite to completion of the LLC conversion. PGE currently has outstanding shares of preferred stock. These shares would have to be eliminated, that is, bought back from their holders (redeemed), before the LLC conversion could take place. PGE has only limited rights to redeem the preferred stock. Beyond those rights PGE cannot force preferred shareholders to sell their stock, nor do we know how Mr. Jubb envisioned PGE would raise the capital necessary to accomplish this task. If the preferred shareholders did not agree to sell their stock, the LLC conversion could not have taken place.

Q. Are there other procedural issues Mr. Jubb's LLC conversion strategy overlooks?

A. Although Mr. Jubb does not specifically address it, we can find no specific time period in which Enron or PGE would have reasonably considered the time-consuming and risky scheme proffered by Mr. Jubb. Immediately after Enron declared bankruptcy, it became engaged in a massive legal proceeding to develop a bankruptcy plan. During, and even prior to, this entire period, Enron was also seeking a buyer for PGE. Enron would have been unlikely to approve any transaction as unusual and risky as the one proffered by Mr. Jubb while it was earnestly seeking a buyer for one of its only financially secure subsidiaries.

It would also have been imprudent for either Enron or PGE to have incurred the substantial legal costs that would have been involved in determining if the proposed transaction was even feasible. As noted above, attorneys would have had to review all of PGE's outstanding contracts to determine if they would allow liquidation of the company. A similar review would have had to have been undertaken with regard to PGE's first mortgage bonds. Tax experts would have had to provide expert opinions as to whether the

IRS could approve such a transaction, and the potential liability that would accrue to PGE customers if the IRS found PGE in violation of the step-transaction or economic substance doctrines.

Q. Mr. Tamlyn, if you had been tax director of PGE throughout the time period after Enron's bankruptcy and prior to the stock distribution, would you have recommended that PGE undertake an LLC conversion?

A. Absolutely not. The risks related to the loss of deferred taxes and the potential for IRS penalties would have been unacceptable, particularly given all of the difficulties described above related to approvals from Enron and various governmental bodies and the significant and likely unrecoverable financial costs. Given the upheaval faced by both PGE and Enron during this time period, it would have been imprudent for the Company to have exposed itself to greater risk and regulatory disapproval. For all these reasons, I would not have recommended that PGE undertake an LLC Conversion.

Q. Mr. Piro, you were Chief Finanicial Officer for PGE throughout the time period described above. If Mr. Tamlyn had presented the concept of the LLC conversion to you, would you have recommended the action to PGE's Board of Directors?

A. No. It was my job during that time period to ensure the financial health and stability of PGE, and to ensure that PGE could continue its core function of delivering safe and reliable power to its customers during the Enron bankruptcy. Given all of the concerns mentioned by Mr. Tamlyn, I would not have considered the LLC conversion as a prudent course of action, and I would not have recommended that PGE expend potentially millions of dollars to pursue such a scheme.

IV. Adjusting Deferred Tax Liabilities

Q. What is your opinion of Mr. Jubb's recommendation to return deferred taxes to customers as they become current?

A. Such a measure would clearly violate IRS normalization requirements and would therefore cost customers approximately $25 million per year by elimination of the rate base offset for deferred income taxes as explained earlier. We describe this issue in some detail in Section III above.

Q. Is Mr. Jubb correct when he contends that SB 408 effectively puts PGE on a "cash method for ratemaking" and continued accounting for deferred taxes would result in double charging customers?

A. No. Mr. Jubb errs when he states that SB 408 effectively puts PGE on a "cash method for ratemaking." COP 100, Jubb/10. SB 408 encompasses both current and deferred taxes. There is no "double charge." Mr. Jubb implies that PGE would charge customers again in current taxes when the deferred taxes are due. Mr. Jubb is incorrect. Under cost-of-service ratemaking, as well as the SB 408 true-up, customers are charged just once, in the year that income taxes are reported in the utility's results of operations report.

V. Taxes Paid to Enron

Q. Do you agree with Mr. Jubb's recommendation with regard to prior income tax payments made in good faith to Enron?

A. No. Mr. Jubb contends that PGE did not file its tax agreements with the Commission as required by his interpretation of ORS 757.495. PGE respectfully disagrees. This matter currently is pending as a matter of law in Docket UM 1262. PGE informed the Commission on an annual basis of payments to Enron for taxes in its Affiliated Interest Filing. The Commission should ignore the recommendation.

VI. Qualifications

Q. Mr. Tamlyn, would you please review your qualifications?

A. I am a graduate of Portland State University receiving a bachelors degree in political science in 1974. I also have a Masters of Taxation degree from Portland State University, received in 1996 and have been a certified public accountant since 1979. I am a member of the American Institute of CPAs as well as the Oregon Society of CPAs and a director for the Portland chapter of Tax Executives Institute.

I worked for the Portland Oregon based CPA firm of Fellner & Kuhn, PC from 1976 to 1987, advising clients on various accounting and tax matters. Subsequent to that I worked in various tax capacities at PacifiCorp, NERCO, PacifiCorp Financial Services and Standard Insurance Company.

I have been the tax director at PGE from March 2005 until the present time.

Q. Mr. Piro, Mr. Tamlyn, 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 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 with respect to the net variable power cost (NVPC) regulatory framework PGE proposed in PGE Exhibit 400.

Q. How is your testimony organized?

A. My rebuttal testimony has four sections after this introduction. Here, I briefly address why PGE proposed a comprehensive NVPC regulatory framework in this general rate case and the positions that parties take on that framework.

In Section II, I discuss the topic central to the disagreement about a regulatory framework for PGE's NVPC: risk. The relevant risk is "the risk that forecasted cost of service will not be the same as actual cost of service" (cost of service risk). I explain how the concept of "expected value power costs" relates to this risk. With the relevant risk articulated, I then explain why PGE's proposed regulatory framework meets the objectives of sound regulatory policy more so than the frameworks the parties propose.

Section III discusses the effect of the Annual Update Tariff on cost of service risk and responds to the arguments the parties offer against including an annual re-forecast of NVPC in the NVPC regulatory framework.

In Section IV, I review the effect of the Annual Variance Tariff on cost of service risk and respond to the parties' arguments against PGE's proposed NVPC regulatory framework and for their alternatives, as the case may be. This section answers:

- Why the Variance Tariff does not need, and should not have, a deadband
- Why the Variance Tariff is revenue neutral under a logical understanding of this term and need not meet the unsupported meaning some of the parties would give it
- Why the Commission should adopt PGE's proposed earnings test rather than the one suggested in Order No. 05-1261 and promoted by the parties in this docket

In Section V, I respond to various other arguments advanced or positions taken by the parties regarding our proposed NVPC regulatory framework.

Q. Why did PGE present a comprehensive power cost framework in this docket?

A. We believe this is the right time and the right forum for the parties, and the Commission, to address all of the aspects of this complicated issue. Through circumstance, not design, the parties and the Commission have addressed these issues in piecemeal fashion over the last six years. Unusual fact situations, truncated proceedings, and frequent surprises have characterized the exploration. CUB expresses extreme frustration with this, complaining that "PGE's unrealistic pursuit of its dream power cost adjustment has cost the Commission, Staff, and the parties a considerable amount of time, resources, and angst." CUB also asserts that we "have wrapped ourselves in a blanket of intentional ignorance in order to pursue [our] vision of the perfect power cost adjustment." (CUB/200, Jenks-Brown/20).

We would be less than honest if we claimed that we felt no such frustration; the charge of "ignorance" does not merit a response.

Q. Do you agree with ICNU that this docket was a "compliance filing" with Order No. 05-1261? (ICNU/103, Falkenberg/26)

A. No. The nature of Docket UE 165 and Order No. 05-1261 did not bind PGE to making a "compliance filing" in this or any other docket.

In Docket UE 165, filed May 2004, PGE proposed a Hydro Generation Adjustment (HGA). Grounded in the fact that it is impossible to forecast the amount of hydro generation PGE will receive in any given year, the HGA mechanism would have included actual hydro generation in PGE's cost of service rates on an actual basis, valuing generation both above and below that assumed at a market price. In March 2005, we reached a settlement with Staff, agreeing to put in place – for two years only – a mechanism called the System Dispatch – Power Cost Adjustment Mechanism (SD-PCAM). This mechanism did not resemble PGE's HGA and PGE made a number of compromises in agreeing to try it experimentally. CUB and ICNU opposed the stipulation. The testimony subsequent to the stipulation addressed only the reasonableness of the stipulation.

On December 21, 2005, the Commission issued Order No. 05-1261, rejecting the stipulation. The Commission kept the docket open, however, "in the event that PGE <u>wishes</u> to submit to the Commission a hydro-related PCA that meets the design criteria" that the Order describes. Order No. 05-1261 at page 14 (emphasis added). By letter dated February 9, 2006, we advised the Commission that PGE had already been working with the parties on power cost adjustment (PCA) issues and that we would file a proposal in the general rate case filing planned for just one month later. We said:

> "We presently plan to include the results of our exploration with the working group in the general rate case that PGE intends to file this year. . . . [W]e are optimistic that the rate case record will contain a full exploration of the Commission's UE 165 guidelines and other issues that have arisen since the record closed in UE 165. For example, we expect that parties will address the differences between the earnings test the Commission suggested for UE 165 and the test used for other mechanisms, such as purchased gas adjustments, and for various deferrals in the past. In the context of a general rate case, the record can also include the cost of capital effects of an earnings test that may systematically (because of the asymmetric nature of NVPC variances) affect a utility's opportunity to earn its authorized return on common equity. We also expect that parties will explore in greater depth the notion of 'revenue neutrality,' which surfaced in UE 165 and appears in the Commission's guidelines but we believe is an incomplete concept at this point."

We also expressed our concern that Docket UE 165, did not "explore all of [the interrelated] issues in part because of its limited nature and in part because of the settlement and resulting focus in the proceeding on the terms of that settlement." We believed these "limitations affected the nature of the record presented to the Commission in providing guidance on changes that would make the SD-PCAM acceptable."

We have done exactly as we said PGE would. We did not continue on a path of developing either a hydro-related PCA mechanism or a variant of the SD-PCAM because we believe a comprehensive approach is superior to a limited approach. It is disconcerting that CUB would label our proposal of a different regulatory framework in this docket "brazen." The term suggests a rigidity to regulation, a foreclosure of alternatives and a denial of respectful disagreement[1] that I do not recognize from past experience with the regulatory process.

Q. Is a general rate case the right forum to explore the issues involved in creating a NVPC regulatory framework?

[1] CUB's testimony ridicules PGE and our proposed NVPC regulatory framework, using terms such as "brazen", "twisted in its knickers," "misguided," "unrealistic," "intentional ignorance." We believe such terms have no place in regulatory proceedings.

A. Yes. As we explained in our February letter to the Commission following Order No. 05-1261:

> "[A general rate case] forum can best accommodate the range of issues implicated by setting cost of service rates for net variable power costs (NVPC), which span from the modeling choices used to develop a base forecast of NVPC to the cost of capital implications of the risk allocations the Commission makes in its treatment of variances between forecast and actual NVPC."

In short, only in a general rate case could all parties – including PGE – present, and the Commission decide, the issues of forecasting NVPC, reconciling NVPC, and cost of capital in an integrated fashion. Our proposed NVPC regulatory framework is much closer than the Commission modified SD-PCAM would have been, to the types of regulatory frameworks in place for the utilities likely to be considered "comparable" by parties assessing our cost of capital. In addition to all of the reasons we gave for our NVPC framework in direct testimony (PGE Exhibit 400), it seems more logical to start this integrated look from a position similar to our comparable utilities.

Q. What positions do the parties take regarding PGE's proposed NVPC regulatory framework?

A. All of the parties oppose our framework; Staff and CUB present alternatives. Staff/800, Galbraith/12; CUB/200, Jenks-Brown/12; ICNU/103, Falkenberg/3.

Under Staff's proposal, the Commission would adopt a NVPC forecast only in a general rate case, regardless how frequently or infrequently that occurred. (Staff/800, Galbraith/15-16). The Commission would also include in PGE's prices any amount by which, during a given year, actual NVPC were lower or higher than this general rate case forecast but only 90% of such amounts that exceed 150 basis points of the required return on common equity (ROE) set by the Commission during the general rate case. Staff includes the earnings test first invented in Order No. 05-1261, under which PGE would not adjust rates for actual costs less than forecasted unless we had already earned more than 100 basis points above our allowed ROE or for actual costs more than forecasted unless we had already earned less than 100 basis points below our allowed ROE.

Under CUB's NVPC regulatory framework, the Commission would adopt a NVPC forecast only in a general rate case, as with Staff's method. (CUB/200, Jenks-Brown/15). The inclusion of the difference between actual NVPC and the forecasted NVPC varies under CUB's proposal, depending on whether the actual NVPC were lower or higher than the forecast. For higher actual NVPC, rates would include 50% of any difference between about $38 million and $61 million (using the UE 115 rate base and cost of capital), and 90% of any difference greater than that. For lower actual NVPC, rates would include 50% of any difference between about $19 million and $30 million and 90% of any difference greater than that.

Q. In general, how do the parties support their positions and proposals?

A. The parties assert that PGE's proposed NVPC framework shifts risk from PGE to customers. Citing a variety of proceedings, the parties argue that PGE must "bear" this risk, using the terms normal, unusual, extraordinary, expected, and stochastic, sometimes in terms of events and sometimes in terms of PGE's financial results. See, e.g., Staff/800, Galbraith/9; CUB/200, Jenks-Brown/21; ICNU/103, Falkenberg/48. The parties also argue that the proposal violates Commission precedent. See, e.g., CUB/200, Jenks-Brown/16; Staff/800, Galbraith/9; ICNU/103, Falkenberg/27. These terms, and the deadbands and other regulatory framework features for which the parties use the terms as support, are simply judgments, based on largely unarticulated views of "what ratemaking is supposed to be."

Q. Do the parties identify or attempt to articulate the nature of the risk they believe PGE's proposed NVPC regulatory framework shifts?

A. No. It is for this reason that I include Section II in this testimony. The relevant risk is that the cost of service prices charged for PGE's on-demand retail electricity service will not reflect actual cost of service. Both customers and PGE bear the cost of service risk. I show that PGE's NVPC regulatory framework reduces this risk, rather than shifts it. In contrast, two of the adjustments to our 2007 NVPC forecast that the parties support (extrinsic value and ancillary services revenue) would shift some of this cost of service risk from customers to PGE. See PGE/1900, Section IV.

Q. Do parties define or provide any analytical content for the event distinctions: normal, unusual, or extraordinary?

A. No.

Q. Do you agree that PGE's proposed NVPC framework violates Commission precedent?

A. No. I address the relevance of prior decisions by this Commission, and relevant decisions from other Commissions, in Section IV.

II. Risk

Q. How is the issue of risk central to the parties' disagreement over a NVPC regulatory framework for PGE?

A. The parties ground their positions opposing PGE's NVPC regulatory framework and/or proposing alternative approaches on the belief that regularly updating the NVPC forecast and reflecting actual NVPC in the cost of service prices charged to customers for on-demand retail electricity service will "shift risk" to customers. See, e.g., Staff/800, Galbraith/9 ("PGE has historically borne power cost risk and should retain a significant portion of this risk."); CUB/200, Jenks-Brown/5 ("power cost variations are a normal and accepted part of forecasted ratemaking, and . . . a utility is expected to manage them and is allowed to benefit from them."); ICNU/103, Falkenberg/27 ("utility shareholders must bear some amount of normal power cost variation between rate cases."). Indeed, CUB charges that PGE has an "unrealistic desire – even expectation – for annual dollar-for-dollar recovery of power costs." (CUB/200, Jenks-Brown/12).

Q. Do the parties identify or explain what risk PGE's NVPC regulatory framework would shift?

A. No. The parties never explain what the <u>risk</u> is that PGE's proposed NVPC regulatory framework allegedly shifts.

A. Cost of Service Risk

Q. What risk does a Commission address when it develops the overall, and component, regulatory frameworks for setting cost of service prices?

A. The risk that a Commission must address when it uses test year ratemaking as <u>part</u> of its regulatory framework for a utility such as PGE is the risk that a utility's prices – and what customers pay for on-demand retail electricity services – will not reflect that utility's cost of service.[2] A close connection between price and cost of service is a critical component of the regulatory bargain for both sides. Oregon's statutory framework is quite specific about the importance of cost: the Legislature has directed electric utilities to offer all of their customers a "regulated, cost-of-service rate option" (ORS 757.603(1)(a)) and stated that "[r]ates are fair and reasonable . . . if the rates provide adequate revenue both for operating expenses of the public utility . . . and for capital costs of the utility . . ." (ORS 756.040(1)).

For convenience, I will call this risk "cost of service risk." Both utility customers and utilities bear this risk. Utilities bear the risk that the test year rates, and revenues collected through them, are too low for the costs incurred in providing on-demand retail electric service. Customers bear the risk that the test year rates, and the bills they produce, are too high for the costs a utility incurs in providing the service.

Virtually every expense for which the Commission adopts a forecast in establishing that test year presents this risk to a utility and to its customers, regardless whether the Commission is basing the forecast on a future year or a historical year adjusted for known and measurable changes. The size of this total risk for a given cost of service component, regardless how it is allocated, depends on how accurately one can forecast it and the utility's ability to control it. These interrelate: typically, the greater control a utility has over a given

[2] CUB appears to believe that the only way that the Commission can set prices is on a test year and, indeed, a future test year. See CUB/200, Jenks-Brown/3. Nothing in Oregon's statutes states this and all evidence is to the contrary, as the Commission has and uses many tools, some statutory and some not, that include in a utility's cost of service prices elements that are not from a future test year.

cost of service component, the less forecasting uncertainty and vice versa.[3] The total size of the risk is the range between the lowest actual amount and the highest actual amount that cost of service component could be during the period the prices are in effect.

An example helps illustrate cost of service risk in terms of forecast uncertainty and utility control. Employee business expense is at one end of the spectrum. Forecast uncertainty is low. Barring highly unusual circumstances, the next year's expense is likely to be close to the prior year, adjusted for inflation/deflation, on the basic types of expense. Similarly, the utility's degree of control is high, again except for inflation/deflation effects. Aiding the degree of control is the number of decisions within this category and the relatively small size of each. Authorize this business trip or not? Approve this use of outside expertise on a given matter or not? For a significant number of the decisions, it may be possible to postpone the expense for some period without much consequence. To greater or lesser degrees, many costs within non-power operations and maintenance expense have these characteristics. The size of the cost of service risk is quite small, even several years after the Commission adopts the point forecast.[4]

Analyzing NVPC in terms of forecasting uncertainty and control shows a marked difference. Forecasting uncertainty can be high, although this will vary from utility to utility depending on its resources. The uncertainty includes both costs within the year the Commission has used for test year rate setting and in subsequent years. Control, generally,

[3] Depreciation and amortization would be the exceptions. Forecasting these costs is quite certain: the depreciation number flows directly from applying the last-approved depreciation study to PGE's current investments and amortizations from whatever orders set the amount and rate applied to it. On the other hand, the utility exercises virtually no control over these costs, other than the incremental control of depreciation associated with new investment.

[4] Rate design can play a role in affecting cost of service risk, particularly over time. Historically, Commissions have designed most of a utility's costs into variable rates. For the fixed costs, that means that load directly affects the cost of service risk. For many years, as customer loads grew roughly at the same pace as the fixed costs, this regulatory framework helped minimize cost of service risk.

is low. The decisions that will affect whether actual cost is higher or lower involve large expenditure amounts and many are in reaction to matters outside the utility's control. Postponing expenditures is usually not an option because that would threaten reliable service.

Q. Does Staff agree that both customers and utilities have cost of service risk?

A. Yes, it appears so. On deposition, Staff witness Maury Galbraith answered the question as follows.

Q. Is it your view that it is only the company that is at risk with respect to variations from expected power costs and the impact of those variations?

A. No, that's not my view.

Q. Would the customers also have a similar risk?

A. Yes, customers have a similar risk. (Galbraith Deposition, PGE Exhibit 1801 pages 3-4).

Q. How does a Commission's overall, and component, regulatory frameworks relate to the size of cost of service risk?

A. If a utility can control a given element of cost of service and/or forecasting uncertainty is low, the Commission need not construct a regulatory framework to lessen the already small size of the risk. If the cost of service risk is high, however, a Commission's overall and component regulatory frameworks can reduce the overall size of the risk by bringing actual costs, in addition to forecasted costs, into the ratemaking process. Use of actual costs, such as through PCA and purchased gas cost adjustment (PGA) mechanisms, directly reduces the size of the risk, regardless of the allocation of that risk between a utility and its customers.

Q. Do the parties agree that PGE's NVPC present forecasting uncertainty and that PGE does not control these costs?

A. Generally, yes. CUB states, for example, that: "PGE does not specifically control hydro conditions; neither does the Company specifically control loads, market prices, or weather… PGE is not expected to control nature or the market." (CUB/200, Jenks-Brown/16-17). On deposition, Staff expressed a similar view regarding PGE's control in the following exchange:

> *Q. Could you tell me which of the factors that drive variation of power cost PGE has control over?*
>
> *A. I'm not sure it has complete control over – over any of the factors that drive variations of power costs. If it did, I assume there would be no variations.*
>
> *Q. Well, does it control load?*
>
> *A. Not completely.*
>
> *Q. Does it control weather?*
>
> *A. No.*
>
> *Q. Does it control market price?*
>
> *A. No. (Galbraith Deposition, PGE Exhibit 1801 pages 13-14).*

ICNU stated: "There is ample reason to believe that prices will deviate from the forecast as events unfold. However, it is impossible to determine exactly what market prices will materialize." (ICNU/103, Falkenberg/4).

Q. Does the Commission have a direct role in allocating cost of service risk?

A. Yes. A Commission allocates cost of service risk – for a given test period – through how it sets the forecast: the point on the spectrum of all of the results the cost could actually be in that year. If that forecast is set such that the probability and size of higher or lower actual costs is even, then customers and the utility have an even share of the risk. If the baseline forecast biases this result in any way, then the bias allocates the risk between customers and the utility.

For example, assume a NVPC forecast of $200 million presented even odds of outcomes higher or lower by $30 million. In other words, customers' risk of outcomes less than $200 million, down to the $170 million lower end of the range, matched the utility's risk of outcomes over $200 million up to the $230 million upper end of the range. If the Commission arbitrarily reduced the NVPC forecast by $20 million, then the Commission would have shifted to the utility a potential $20 million loss that customers otherwise would have faced. In other words, for outcomes between $180 million and $200 million, the utility would now bear the cost of service risk, in addition to the cost of service risk it bore for outcomes over $200 million.

Q. Can reducing cost of service risk change the allocation of the risk?

A. Reducing cost of service risk re-allocates that risk only if the Commission does not allocate the risk evenly to begin with or brings actual costs unevenly into the ratemaking process. Using the uneven allocation example I gave above, including actual costs in the regulatory framework could partially or totally "undo" the uneven allocation achieved by the forecast. Similarly, if a regulatory framework brings only actual costs lower than the forecast (such as the IT True-up in the Docket UE 115 stipulation) or costs higher than the forecast (such as a one-time deferral of excess power costs) into ratemaking, the risk allocation would change, at least for that instance. Staff explained this part of the concept of cost of service risk well on deposition:

Q. And can you explain to me how a PCA mechanism could bias the expected level of power cost recovery in your words?

A. A one-sided PCA mechanism that only provided recovery for higher power costs and didn't provide refunds for lower power costs, that type of one-sided mechanism would bias the overall expected level of recovery.

. . .

If the mechanism only triggered when costs increased and didn't trigger when costs decreased, even assuming there was an equal likelihood of the cost increases and cost decreases, you'd get, you'd get a different expected recovery than you would if you just set power cost on normalized rate-making principles. (Galbraith Deposition, PGE Exhibit 1801 pages 1-2).

Q. Does Staff believe that a PCA mechanism re-allocates as well as reduces risk?

A. It is not clear. The following exchange during deposition appears to acknowledge that a PCA mechanism reduces risk for both customers and the utility but indicates that the reduction for each comes at the expense of the other. In other words, the PCA mechanism shifts the utility's allocation of the cost of service risk to customers and shifts the customers' allocation to the utility:

Q. In the first sentence again after page 9, after you say "the amount of risk reduction," then you add, "or conversely earnings stability." Is that meant to refer to earnings stability with respect to both customers and the utility, or just one of the two?

A. The important thing to remember here is is that in – a PCA mechanism allocates risk between shareholders and customers. And so the use of the phrase

> *"risk reduction" here is pointing out that a risk reduction for shareholders is a – is a risk increase for customers. And so I phrased the first sentence here from the perspective of a risk reduction for shareholders, or conversely, an improvement in their – in the stability of shareholder earnings. There is a flip side to that first – that first sentence, which would be: from the customer perspective." (Galbraith Deposition, PGE Exhibit 1801, page 4).*

Even if one accepts the view that shifting occurs, when it is done, the risk is still reduced for both. If the Commission's allocation of cost of service risk was even to begin with, the risk reduction is even for both.

Q. Does Staff contradict the conclusions you have drawn from these explanations, however?

A. Yes. Also during deposition, Staff stated that:

> *Q. And, therefore, does the absence of a deadband and a 90-10 sharing as proposed by PGE shift all of the customers' power cost risk to PGE in the same way you've said that it shifts all of PGE's power cost risk to the customers?*
>
> *A. Well, the shifting needs to be compared to some baseline level of risk allocation. The baseline level of risk allocation, or the traditional level of risk allocation, is that between rate cases the utility bears the – both the higher costs and the lower costs. And so compared to that baseline, PGE's proposal shifts risk to customers. (Galbraith Deposition, PGE Exhibit 1801, pages 11-12).*

One can reconcile this only by concluding that, even though customers bear cost of service risk and a PCA mechanism could allocate that risk to PGE, this cannot happen now because the Commission "shifted" that risk to PGE some time ago. Thus, a PCA mechanism reduces risk as I explained, but only because it is presumed that PGE bears customers' risk currently.

Q. Does this make sense?

A. No. PGE does not "bear" – in the sense of potential loss – customers' risk that actual cost of service will be lower than forecasted cost of service. The Commission cannot shift it to us. The Commission can decide that the cost of service risk is not large for either customers or the utility and, thus not address it. But the Commission cannot have us bear customers' loss potential.

B. Expected Value Power Cost and Cost of Service Risk

Q. Can the concept of "expected value power cost" tell us something about the size of the NVPC cost of service risk?

A. Yes. As ICNU stated: "Stochastic models would provide more insight into both the expected value and the distribution of power cost forecasts."

Q. Would you please review, briefly, what "expected value power cost" is?

A. PGE testified in Docket UE 165 that: "Expected value power cost is a method of forecasting power cost that simulates a spectrum of alternative states for relevant variables to develop a central power cost estimate. By contrast, the current methodology employed by MONET is "deterministic," taking into account only one estimate of the relevant variables." Further, "to rigorously forecast expected value power cost under uncertainty, we would stochastically vary all uncertain variables, with appropriate correlations or fundamental economic relationships. . . . One technique would be to use random draws in a Monte Carlo approach. To do this adequately is a large task, and we do not currently have the modeling capability to do so." Exhibit 1802 includes the relevant sections of this Docket UE 165 testimony.

Q. Did PGE engage a consulting firm to work on expected value power costs?

A. Yes. We agreed to do this as part of our stipulation with Staff in Docket UE 165 and, even though the Commission rejected the stipulation, we fulfilled our commitment and retained PA Consulting Group (PA) for the work. The report we received is included as PGE Exhibit 1803. PGE sent a cover letter, along with distribution of the PA report, to parties to the UE 165 docket. This letter noted a number of issues related to the PA report. PGE Exhibit 1804 is a copy of the cover letter, dated July 18, which PGE included with distribution of the PA report.

We initially asked that PA develop a "cost simulation model" meeting the requirements we identified in our testimony on this issue in Docket UE 165. PA found that "an important factor limiting the precision of any probabilistic cost simulation is the availability of data describing the distributions and dependencies of its uncertain inputs." PGE Exhibit 1803 at page 1-1. Nonetheless, PA produced a limited prototype model on our request.

A 1000-iteration run of the PA cost simulation model produced a "descriptive model". The range of outcomes from the distribution of all of the inputs, and the interrelationship of those inputs, was $350 million around a "mean" of $650 million. Thus, for PGE and our customers, the size of the cost of service risk associated with NVPC can be very large.

Q. Does the PA simulation model tell us something about how the current NVPC regulatory framework allocates the cost of service risk?

A. Yes. The results showed a significantly skewed distribution, with a standard deviation of $55 million. PA indicated its belief that the standard deviation is likely understated. In addition, the difference between the base case value and the "expected value" was a positive $10 million. This suggests, were one to attempt to use the descriptive model for ratemaking, that the test year NVPC forecast should be $10 million higher than MONET indicates. The conclusion corroborates our belief that the MONET point forecast likely does not evenly allocate NVPC risk but is lower than a probabilistic determination would indicate.

C. Is There A Risk Involved Other Than Cost of Service Risk?

Q. If adoption of a PCA mechanism does not shift cost of service risk between utilities and customers, is there another way to understand the parties' assertions regarding risk?

A. Perhaps. The parties' assertions may reflect a view of the on-demand retail electricity service that PGE must offer our customers different from PGE's view. We understand that product to be "cost of service" retail electricity, consistent with the Legislature's requirements adopted in 2001. The parties' positions imply what I will call a "no true-up" product: The Commission sets prices for PGE's electricity service only in a general rate case, PGE must provide all of the service requested, whenever requested, at that price unless extraordinary circumstances (akin to "force majeure" in the commercial setting) occur. If extraordinary circumstances occur, PGE may recover some of the cost of the power it has actually used to provide this retail service (assuming it demonstrates prudence) but only after it has absorbed enough to ensure that, for that year, its investors do not recover the return on equity the Commission last found that they required. See, e.g., ICNU/103, Falkenberg/45; CUB/200, Jenks-Brown/17. This is a product that may be available from power marketers or brokers operating in the wholesale market or providing retail electricity service outside of regulation at market-based prices. It is not the cost of service-priced, on-demand retail electricity service Oregon obligates PGE to offer to anyone located within our service territory.

Q. Didn't PGE suggest, in 2000, that retail customers valued this type of "no true-up" (unless the extraordinary occurs) retail electricity service?

A. Yes. ICNU cites the testimony we presented in the summer of 2000 in Docket UE 113. (ICNU/103, Falkenberg/45). When PGE prepared that testimony, we believed that some of our customers – particularly those that had worked so hard to achieve passage of Oregon's electric restructuring law – valued electricity prices not subject to any after-the-fact adjustment, which is a characteristic of market-based prices. We said in UE 113 that: "Until our customers have a choice of products, we would prefer not to require all to choose an electricity product that does not include price finality as a feature." (UE 113, PGE/100, Pollock-Lesh /13). In 2001, the Oregon Legislature enacted what became ORS 757.603: the statute under which PGE <u>must</u> offer cost-of-service priced electric service to all customers. Following the Legislature's change in the law, we developed an electricity product by which at least our highest consumption customers can obtain retail electricity service not subject to any true-up: Schedule 483. What is significant about Schedule 483 is that it de-links the customer who chooses it from cost of service entirely. As I explain below, combining cost of service pricing with a "no true-up" on-demand retail electricity service is inconsistent and arbitrary.

Q. Do you agree with ICNU that PGE's proposed NVPC framework violates the concept of "price finality?"

A. No. The cost of service price the Commission sets, from time to time, for our on-demand retail electricity service, is the price customers taking this service pay. It is final until changed by future Commission action. Whether the Commission has included within that price actual cost or revenues from some prior period, or used an historical or a future test year, does not make the price less final.

Q. How is combining cost of service pricing with a "no true-up" view of on-demand retail electricity service inconsistent?

A. Cost of service pricing is inconsistent with a "no true-up" view for two reasons. First, such a view has little to do with the resources we actually have for the cost of service product we provide retail customers. Second, it separates arbitrarily for ratemaking purposes the relatively certain fixed costs included in a test year at actual, embedded, historical amounts and the uncertain variable costs, included in cost of service under this view only on a forecast basis that may vary hugely from actual cost.

Again, perhaps the ICNU testimony sets up most clearly our first issue with a "no true-up" view of on-demand retail electricity service. ICNU claims that PGE can "undertake prudent risk management strategies to manage its power cost risk" (ICNU/103, Falkenberg/33) and suggests that PGE's "real problems" are its: "load forecast uncertainty, a resource deficit resulting in a need for the Company to contract for substantial amounts of energy on the wholesale market, a heavy reliance on gas-fired generation, and reliance on hydro generation." Id. at pages 30-31. ICNU urges PGE to "address the causes of its problems." Id. With different resources, we could much more easily offer on-demand retail electricity service with "no true-up" or inclusion of actual NVPC within the regulated price. It would be still easier to do this if we did not offer service on-demand but, in fact, offered products similar to those available on the wholesale market, such as take-or-pay, on- and off-peak blocks of power.

Even if we wanted to "address the causes of our problems," however, we have little independent ability to adjust our resource portfolio, particularly long-term resources. If we own those resources, we cannot sell them without OPUC approval. The last time we proposed to sell a long-term resource, the Commission resoundingly denied that application. (OPUC Order No. 00-111). If we have contracts, we cannot breach those contracts and must wait until their expiration. Although we can, and do, routinely replace our short-term contractual purchases as contracts expire, our goal is to add long-term resources only after an IRP process in which all interested persons participate.

Our inability to adjust much of our resource portfolio contributes to our second issue with a "no true-up" view of our retail electricity service. The parties' positions attempt to separate the characteristics of various resources that result in uncertain actual variable costs from the certain actual fixed costs of the resources. The parties support without question including the actual fixed costs of our resource portfolio, such as the low-cost contract with Chelan County for a percentage of the capability of the Rocky Reach hydro plant, in test year cost of service at its historical cost. The parties do not support, however, including the actual variable costs associated with that contract, which result from both the MWhrs produced by the plant and also the value or costs of producing more or less than the average assumed for creating a test year forecast. Our Boardman plant is another example. The depreciated investment in this plant is just $150 million and the test year forecast reflects this actual amount. But the parties do not want cost of service prices to reflect the actual variable cost of Boardman, whether the result of its production and its significantly lower-than-market variable cost is more or less than the forecast NVPC.

A holistic and internally consistent view of PGE's resource portfolio would not separate the fixed costs from the variable costs. The Commission should not recognize such an artificial separation in considering the best regulatory framework for PGE. This is why our opening testimony carefully reviewed how our proposals related to both the fixed and variable costs of PGE's resource portfolio. The parties address only the variable costs, as if those are somehow separable. Our cost of service resources create the cost of service risk the Commission must address through a regulatory framework. A regulatory framework that uses an embedded cost-based view for fixed costs but imposes market-based view for variable costs is untenable.

D. Cost of Service Risk and Regulatory Frameworks

Q. How would you describe PGE's current NVPC regulatory framework in terms of cost of service risk as you articulated it above?

A. The Commission has allocated the cost of service risk for NVPC as well as current forecasting tools permit. We believe that the resulting point forecast is probably lower than the point at which the size of the range would be evenly split, for a given year, between customers and PGE. The annual update of the NVPC forecast through the RVM helps constrain the size of the cost of service risk range by ensuring that the forecast at least reflects the cost of power and fuel we have actually purchased. Other than this, the current NVPC regulatory framework does not reduce the cost of service risk: PGE and customers both bear a large risk.

Q. How would you describe PGE's proposed NVPC regulatory framework in terms of this risk?

A. Our proposed NVPC regulatory framework does not change the allocation of cost of service risk for NVPC; we propose to continue using the same tools to create a forecast of NVPC. The Annual Update maintains the role the RVM had in terms of constraining the size of the risk's range. Regarding the size of cost of service risk, however, our framework significantly reduces this risk by bringing a significant amount – 90% – of actual NVPC into the ratemaking process.

Q. How do the frameworks the parties propose affect customers' and PGE's cost of service risk?

A. Removing the Annual Update does not change the allocation of NVPC cost of service risk for the year the forecast relates to but increases the size of the risk in subsequent years. It raises a significant probability of unpredictably changing the allocation of risk in those later years because no one has attempted to incorporate recent information. Moreover, as discussed in PGE Exhibit 1900, Section IV, Staff and ICNU propose adjustments to the forecast that further remove it from an even allocation of probabilities of outcomes. The deadbands and earnings tests included in the Staff and CUB proposed frameworks significantly lessen the reduction to cost of service risk that customers and PGE would otherwise experience from adding a PCA mechanism to the NVPC regulatory framework.

Q. Won't NVPC cost of service risk "balance out over time," making it unnecessary for the Commission to adopt a regulatory framework that reduces the risk?

A. No, no one has offered – nor could they create – any evidence on which the Commission could rely to conclude that NVPC cost of service risk will balance out over time. ICNU makes the bold assertion that: "power cost variances tend to cancel out over time" (ICNU/103, Falkenberg/30) but points to nothing other than a chart PGE prepared to demonstrate that year to year variances can be large. See PGE/400 Lesh-Niman/34. CUB draws a similar conclusion from this chart, adding that PGE enjoyed "a net of over $100 million in power cost variations over the period." (CUB/200, Jenks-Brown/4-5). CUB's second conclusion has no basis because the chart does not reflect NVPC forecasts used by the Commission for ratemaking over the period. Only since 2002 has the Commission adopted an annual NVPC forecast. For all of the years on the chart prior to 2002, we reconstructed a NVPC forecast for illustrative purposes, but these amounts have nothing to do with the NVPC forecast used in test year ratemaking.

These 13 years tell the parties and the Commission nothing about the preceding years or, of greater importance, the years yet to come. If the parties believe that it is possible to demonstrate, with some confidence, that the NVPC cost of service risk will balance out over the next five years, ten years, or even 20 years, we would greatly appreciate seeing such analysis.

Q. Doesn't the use of 69 water years in forecasting test year NVPC mean that at least hydro production ups and downs will balance out over time?

A. No. Setting aside for a moment the interaction of hydro production with other NVPC input variables, all that the 69 water years tell us is the size of the cost of service risk associated with hydro production. In other words, we know – with some confidence – both the least and the most amount of hydro production we might experience in a given year and, for that year, what this likely is worth valued at a certain market price. No one can claim that outcomes outside this range of data are impossible but they are unlikely.

The 69 years tell us far less about the frequency with which any given water year will occur. While we know the frequency of each within the 69-year series, that is a relatively small data set for statistical purposes. Moving further into the realm of pure speculation would be any conclusion from the data set about the pattern with which various water years might appear. Will the pattern of the last 69 years exactly repeat in the future? From what year forward? The answers anyone might give to such questions would be meaningless.

What if the pattern of the next 20 years was 10 "above average" years in a row and then ten "below average" years in a row? These balance out over time (again assuming nothing else about how hydro production interacts with changes) but does ignoring this variation make sense for customers or for the utility? Would it achieve inter-generational equity among customers? Could PGE maintain financial health during the latter ten years? Would customers be pleased with the results of the first ten years?

Q. Assuming PGE could develop the data set and capability to perform expected value power cost modeling, would that provide the Commission confidence that higher and lower NVPC would "balance out" over time?

A. No, not at all. Here's what one could conclude from the prototype model PA created and ran. If:

- over the next 1000 times (say annually) that the Commission engaged in ratemaking using a NVPC forecast based on this model, and
- none of the inputs, the inputs' distributions, or the relationships among the inputs changed,

Then one would <u>expect</u> that the actual NVPC annual outcomes higher and lower than the average over the 1000 times would balance out.

The "ifs" are absurd. This is why PA cautions against using expected value power cost modeling in what they call a "prescriptive" manner; i.e., once and for all.

Q. With respect to NVPC cost of service risk, do you agree with Staff that the degree of company control over the cost of service elements in question is irrelevant (Staff/800, Galbraith/11)?

A. No, the amount of control a utility has is highly relevant to cost of service risk and whether the Commission should consider reducing the risk – to customers and the utility – through a regulatory framework. The amount of control a utility can exercise over an element of cost of service affects the size (range of uncertainty) of the risk that actual cost of service will depart from forecasted cost of service, the likelihood that this will happen, and a utility's ability to minimize the effect of the uncertainty if it manifests itself.

Q. Is an Local Distribution Company's (LDC's) lack of control of the cost of purchased gas the major reason for the regulatory framework the Commission has adopted for Oregon's LDCs?

A. Yes. The Commission explained, in 1989, that this regulatory framework (at the time, an annual forecast of purchased gas costs and inclusion of 80% of the difference between actual and forecasted costs in cost of service prices) was appropriate for cost of service changes that a "utility incurs on a continuous basis and over which it has little control." Docket No. UG 73, Order No. 89-1040 (Aug. 4, 1989).

The parties argue that LDCs and purchased gas costs are different because, in CUB's words, "a gas utility is simply a price-taker on the gas market (and the Commission allows the gas utility to pass that price through, barring imprudence)." (CUB/200, Jenks-Brown/11). The distinction overly minimizes the decisions an LDC makes. LDCs must decide when to purchase gas and how much to purchase. If an LDC has storage assets, it must decide how best to use that storage. As a given year unfolds, an LDC must respond to imbalances between the gas it has and the gas its customers are consuming, using a combination of market purchases, sales and storage decisions. Similarly, this view overly emphasizes the decisions an electric utility can make to "manage" its NVPC.

Q. What can an electric utility do to manage NVPC?

A. A utility can manage generation dispatch, power and fuels procurement, power operations, and risk management as an integrated business. See UE 149, Exhibit 200, generally pages 3-8 which is included as PGE Exhibit 1805.

Our ability to manage NVPC mitigates the range of cost of service risk but not to a very great extent. Again, this conclusion can differ among utilities and for one utility over time. If, for example, a utility had some hydro generation – as we do – but also had a significant excess of low variable cost generation and the NVPC forecast did <u>not</u> assume that the utility sold all available MWhrs at a market price, that low-variable cost generation would be available should the "average" hydro production not appear. To some extent, this example describes PGE at the end of the 1980s and early 1990s, before Trojan's closure and before adoption of NVPC forecasting techniques and a model that essentially sells every MWhr of energy available in the test year at a market price.

Now, the primary tool we have to "manage" NVPC is to displace or run our natural-gas fired generating plants depending on market prices and our load-resource balance. Thus, under circumstances such as lower-than-average hydro production, we might be able to run Beaver for the product of the market price of natural gas and Beaver's heat rate at slightly less than we could purchase power on the market. The "savings" are quite small. In any case, it is the market price of gas and electricity that control these decisions just as they do for an LDC and PGE is a price taker in these markets for both purchases and sales.

The prototype model PA prepared that I discussed above includes within its results all of our ability to "manage" NVPC. The size of cost of service risk and standard deviation remain large – many times larger than the cost of service risk for any other element of our cost of service.

Q. Do the parties' positions on a NVPC regulatory framework all rely on the assumption that PGE has a significant ability to manage NVPC?

A. Yes. Staff claims that PGE "does have considerable ability to manage its power costs." ICNU says that "PGE . . . can undertake prudent risk management strategies to manage its power cost risks." (ICNU/103, Falkenberg/33). To be fair, however, much of what ICNU suggests are strategies available at an additional cost. See, e.g., Id at page 32. As indicated above, maintaining excess low variable cost generating capability to replace a temporary lack of other such low variable cost generating capability assumed available in the NVPC forecast would reduce the range of NVPC cost of service risk. It does so primarily, however, by creating unavoidable fixed costs. CUB's opinion on PGE's ability to manage NVPC is perhaps the most extreme. CUB asserts that: "If an electric utility performs well between rate cases, it can keep the benefit of the low costs; if the utility performs poorly, its financial performance will suffer accordingly." (CUB/200, Jenks-Brown/11). Outcomes within the range of cost of service risk have little to do with our <u>performance</u> or management ability.

Q. Do PGE's management decisions regarding generating plant maintenance and capital additions affect NVPC cost of service risk?

A. Yes, to some extent. Presumably sound maintenance practices and capital investment to add redundancy or forestall potential problems reduces the likelihood of forced outages and vice versa. To this extent, an electric utility does differ from an LDC. Again, however, these management decisions affect only the edges of the cost of service risk associated with NVPC. A utility can only "make" a generating plant so reliable and there is a trade-off between the amount spent in O&M and capital additions and the value gained in increased availability.

Q. Does PGE's proposed NVPC regulatory framework recognize and incorporate what ability PGE has to "manage" NVPC?

A. Yes. The 90-10 sharing of actual NVPC that we propose aligns the interests of PGE and our customers as we make the decisions that work around the margins of the events driving actual NVPC in any given year. Staff and CUB also incorporate this feature, albeit after the significant deadbands they propose. In addition, we expect any extended forced outage would prompt a review of PGE's prudence with respect to maintenance and capital decisions.

E. Risk Reduction Outcomes for PGE and Customers

Q. You explained above that PGE's proposed NVPC regulatory framework reduces cost of service risk for PGE. Would PGE's cost of capital reflect the reduction in cost of service risk?

A. Theoretically, yes. If PGE's present authorized cost of capital reflected our portion of the total NVPC cost of service risk, then Commission action to reduce that risk would reduce our cost of capital, all else being equal. The "if" is important, however. If the cost of capital the Commission would authorize does not reflect any adjustment for the NVPC cost of service risk PGE would bear without our proposed regulatory framework, then no reduction is warranted.

Q. Do the Commission orders indicate, and the parties suggest, a connection between cost of capital and the regulatory framework for NVPC?

A. Yes. For example, in Order No. 05-1261, the Commission stated that "adoption of the two-part mechanism outlined here may well shift risks to customers that they have not borne under the sporadic use of deferrals and PCAs in the past. If so, we will consider the reduced risk for the company in setting ROE in the future." CUB's testimony asserts that: "If the Company would like a regulatory framework that eliminates uncertainty and risk, then its return on equity should be adjusted to that of Treasury bills, about 5%." (CUB/200, Jenks-Brown/7).

It is interesting to note that the parties' view of the effect of a NVPC regulatory framework on cost of capital appears only to work one way: frameworks that bring rates closer to actual cost of service reduce cost of capital while frameworks that allow significant variations between assumed, forecast test year NVPC and actual NVPC do not increase cost of capital. This seems unlikely, and the parties present no such evidence.

Q. Do many of the utilities the parties use as "comparable" for purposes of cost of capital analysis have NVPC regulatory frameworks similar to what PGE proposes?

A. Yes. Section III of PGE Exhibit 2000 discusses Staff's inclusion of utilities that have PCAs in its sample. PGE Exhibit 2000 concludes that PGE's cost of capital, including required return on equity, is higher without our proposed regulatory framework.

Q. Would reducing PGE's NVPC cost of service risk benefit customers?

A. Yes, it could. Leaving this risk with PGE will raise the fixed costs of new investment in the system. These costs, once incurred, are not avoidable. Incurring higher fixed costs to avoid periodic NVPC outcomes in which actual NVPC exceeded forecast NVPC seems like a poor bargain.

Q. Does reducing cost of service risk for customers have any benefits?

A. Yes. Reducing cost of service risk for customers has at least two benefits consistent with sound regulatory policy. First, reducing this risk means that, on a relatively current basis, cost of service prices will more closely reflect cost of service. The resulting price signal will enable better consumption decisions. Second, reducing this risk also improves inter-generational equity among customers because we have no idea how the outcomes of actual NVPC will array themselves around the forecast NVPC. Customers could, for 10 years, experience the risk of actual NVPC lower than those forecasted only to have this flip in the following 10 years. Over 20 years, the customer base is likely to undergo significant change.

Q. Have the parties demonstrated that not reducing this cost of service risk, or reducing it only partly by applying a deadband, will produce benefits for customers?

A. No. No party has attempted such a demonstration. I address the unsupported reasoning the parties provide in Section IV. A.

Q. What conclusions do you reach in this section of your testimony?

A. My conclusions include:

- The Commission must set policies that fairly allocate cost of service risk between customers and utility investors and should set policies to reduce cost of service risk when necessary to minimize a utility's cost of capital and improve price signals to customers.

- Expected value power costs are not an appropriate basis for rate making, but preliminary studies indicate that expected power costs are greater than the MONET forecast.
- “No true-up” is not consistent with cost of service rate making.
- PGE’s proposed NVPC regulatory framework reduces NVPC cost of service risk relative to other parties’ proposals.
- The Commission’s cost of capital and NVPC regulatory frameworks must be consistent.

III. The Annual Update Tariff

Q. How does PGE's Annual Update tariff relate to cost of service risk?

A. The Annual Update tariff affects cost of service risk in two ways. First, by annually updating costs that can be certain – such as those associated with actual fuel, power and transportation contracts – it reduces the size of the cost of service risk. Second, the Annual Update tariff helps the Commission maintain the allocation of NVPC cost of service risk it has chosen. As I explained in Section II, setting the forecast is what allocates the risk of variance from cost of service between a utility and its customers. The older a test year forecast, the greater the odds that the risk allocation becomes uneven. This is not a significant concern for many components of non-NVPC O&M, which tend to change gradually. For NVPC at 50% of PGE's revenue requirement, however, allowing the forecast to become out of date is a significant concern.

Q. Can you illustrate this?

A. Yes. Suppose that in year one, our forecasted NVPC was $800 million and that this evenly split the risks that the actual NVPC would be higher or lower. Then, in year two, our forecasted NVPC falls to $700 million but we make no change because no process requires it. Because the NVPC forecast upon which the Commission set our cost of service rates now exceeds the new NVPC forecast baseline, the regulatory framework has shifted risk to customers.

Q. Does your Variance Tariff mitigate this?

A. Yes. Updating actual power and fuel contracts annually lessens the size of the cost of service risk. However, it does not totally eliminate the risk resulting from allowing the forecast to become out of date.

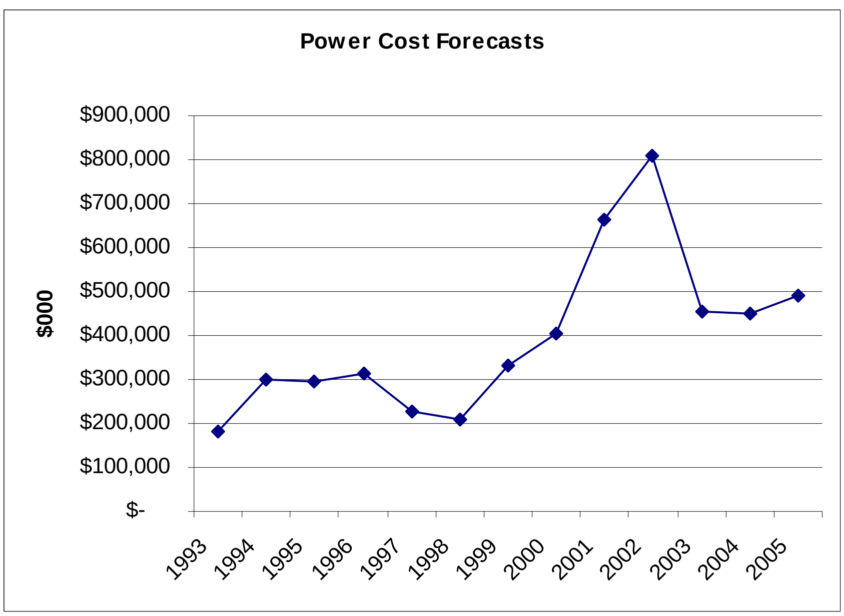
Q. What positions do the parties take on the Annual Update Tariff?

A. Staff opposes the Annual Update Tariff because Staff believes that year-to-year NVPC forecasts do not exhibit enough change – up or down – to warrant continuing the annual update begun in 2001 with the RVM. (Staff/800, Galbraith/14). ICNU opposes it. (ICNU/103, Falkenberg/3). CUB also opposes it and also suggests modifications if the Commission nonetheless adopts it. See CUB/200, Jenks-Brown/13-14.

Q. Do you agree with Staff's conclusion that year-to-year NVPC forecasts do not exhibit much change?

A. No. The graph below shows PGE's forecasted annual net variable power costs for the 1993-2005 period, consistent with the data used to construct the graph of power cost variances on page 34 of PGE Exhibit 400.

Figure 1



The data make it clear that NVPC forecasts can vary greatly from year to year. The cumulative increase from 1998 to 2002 was almost $600 million, and the decrease from 2002 to 2003 was more than $350 million.

Q. Did Staff support their conclusion that PGE's annual forecasted NVPC did not exhibit "the highly dynamic year-to-year change that would necessitate an Annual Update Mechanism?" (Staff/800, Galbraith/13).

A. No. On deposition, Staff explained:

> *Q. What percent changes from year to year in these time series would be necessary before you declared those changes dynamic?*
>
> *A. I didn't have a particular percentage change from year to year in mind when I wrote – when I made that statement.*
>
> *Q. What percent changes would be highly dynamic?*
>
> *A. I didn't make that determination either.*
>
> *Q. Did you actually calculate the percent changes in those time series?*
>
> *A. No. (Galbraith Deposition, PGE Exhibit 1801, pages 15-16).*

Q. Did any party rebut that using an Annual Update Tariff will better match costs and prices?

A. No.

Q. Do you agree with Staff that "the benefits of a prospective automatic adjustment clause [do not] outweigh its regulatory burdens"? (Staff/800, Galbraith/14).

A. No.

Q. Are you amenable to a different review schedule for the Annual Update to address CUB's concerns and to providing the notice they request regarding shifts in the forward curve?

A. Yes. We are open to the Commission adopting whatever review process for these adjustments the Commission deems necessary. And we are happy to provide CUB the information they are seeking regarding any curve shift.

Q. What is your response to ICNU's suggestion that, if the Commission approves the Annual Update Tariff, PGE should include within the update any increases in plant capacity created by new investment, such as has occurred recently for both the Boardman and Colstrip coal plants? (ICNU/103, Falkenberg/48).

A. ICNU's argument is that, in general, the level of capital additions assumed in a test year forecast will cover capital additions that increase plant capacity. ICNU presents no analysis showing this to be the case. This may be correct for some capacity increases, but not for others that involve significant projects. We still are willing to work with the parties to devise a method of allocating the benefits and burdens of significant plant upgrades before a general rate case that updates rate base for these investments. See PGE Exhibit 400 at page 29.

IV. The Annual Variance Tariff

A. The Annual Variance Tariff Does Not Need A Deadband

1. Deadbands and Cost of Service Risk

Q. How does the inclusion of a deadband in a PCA mechanism relate to the cost of service risk you discussed in Section II?

A. As explained above, a deadband reverses some (depending on the size of the deadband) of the reduction in the cost of service risk that a PCA mechanism otherwise would accomplish.

Q. Did you address in Section II the parties' arguments that designing a PCA mechanism without a deadband would shift risk from PGE to customers?

A. Yes.

Q. What arguments that the parties raise regarding a deadband remain?

A. The parties primarily argue that Commission precedent requires that any PCA mechanism for PGE include a deadband. As I discuss below, the Oregon decisions cited are not on point with the possible exception of Docket UE 165. With respect to Order No. 05-1261, we ask that the Commission consider the role of a deadband anew, given that the PCA mechanism we are proposing differs significantly from the temporary, stipulated, SD-PCAM before it in that docket and given all of the evidence in this case.

Moreover, other Oregon decisions relating both to PGE and to LDCs support a conclusion that a PCA mechanism need not contain a deadband. With respect to non-Oregon cost of service electric utilities, no party has rebutted the conclusions in our opening testimony that:

- The use of regulatory tools that allow frequent re-setting of cost of service prices for power cost components, outside of a general rate case, is common among other states; and
- The use of regulatory tools that adjust rates for differences between forecasted power cost components and actual power costs incurred is common in other states.

The parties variously argue that their approach is "traditional" (Staff/800, Galbraith/15) and that PGE's is "absurd" or "unrealistic" (CUB/200, Jenks-Brown/6 and 12). Most states, apparently, do not follow this tradition or view taking action to reduce cost of service risk as absurd or unrealistic.

Because understanding where the current "deadband" came from is instructive in understanding the state of Oregon precedent and guidance and the practice of other states, I address that first below, followed by PGE's rebuttal to the parties' argument concerning precedent.

2. Deadbands and Analysis

Q. The touchstone for the parties is a 250 basis point deadband. (See Staff/800, Galbraith/16; CUB/200, Jenks-Brown/21). Where does this come from?

A. Staff explained the derivation of the 250 basis point deadband on deposition in the following exchanges:

Q. What are extreme fluctuations in NVPC?

A. Well, in past testimony – and you see some of that testimony referenced at the end of that paragraph – Staff has argued that an extreme fluctuation in net variable power costs would be roughly equivalent to 250 basis points of net variable power costs [corrected later to 250 basis points of return on equity].

At the same time, in those previous proceedings, Staff has indicated that this is a matter of judgment, and that it would be important to look at the distribution of net variable power costs to determine that.

. . .

Q. Tell me what – how the concept of an extreme fluctuation in NVPC has any relationship at all to 250 basis points of return on equity?

A. Well, in – the 250 basis points of return-on-equity standard I think was first put forward in docket UM 995 by Staff. And it represented an opinion that that was the level of variation in costs that a utility would be willing to absorb without coming to the Commission and filing a rate case.

. . .

Q. Now, doesn't that prior testimony of yours focus, really, on the impact of cost changes on the utility, not whether fluctuations in NVPC are extreme or not?

A. I think it's a combined focus. I think the two things, to a certain extent, go hand in hand. That – in other words, that if there was an NVPC fluctuation that resulted in – or that was the equivalent to 250 basis points of ROE, that it would be both an extreme fluctuation and be at the point where it was starting to cause financial impact.

. . .

Q. Would extreme – would your view of what constitutes an extreme fluctuation change, depending upon the size of the utility?

A. My view of what an extreme fluctuation is depends on the distribution of a utility's net variable power cost. . . . Staff has been interested in trying to develop that distribution of power costs and look at that distribution of power costs; we haven't focused solely on the 250-basis-point standard.

. . .

Q. So if you haven't done [stochastic power modeling], how would you know that that distribution had any relationship to, quote, extreme fluctuations?

A. I'm simply saying that conceptually that's how you would, would look to determine what level of power cost deviation represented an extreme fluctuation in NVPC.

Q. Would it be true, then, that without stochastic power cost modeling we wouldn't be able to answer that question.

A. No, not necessarily.

Q. How would we answer that question, without stochastic modeling?

A Using judgment, as was done in docket UM 995, and using the 250 basis points of ROE standard. (Galbraith Deposition, PGE Exhibit 1801, pages 4-10).

Q. How did Staff arrive at the 150 basis point deadband used in the NVPC regulatory framework it proposes in this case?

A. Staff reasoned that the ongoing nature of the PCA mechanism "allowed an opportunity to use a narrower deadband" and that eliminating the Annual Update tariff shifted some risk to PGE that Staff could recognize with a smaller deadband. (Staff/800, Galbraith/16).

Q. Given this, what is your understanding of where the deadband concept came from?

A. Staff developed what it now calls the 250-basis-point-standard in the context of a one-time request by a utility to defer costs. It was a matter of judgment at that time, based on Staff's view of the deferral action as a substitute for an interim rate case. Neither Staff, nor any other party, evaluated then or since, the appropriateness of applying this "standard" to a reduction in cost of service risk for customers and utilities. Although Staff did consider the ongoing nature of a PCA mechanism in reducing the deadband, the deadband concept remains grounded in assumptions regarding when the utility, or presumably the Commission on behalf of customers, would seek interim rate changes. Neither Staff, nor any other party, evaluated whether any reduction in the ongoing cost of service risk of NVPC for customers should be limited by the amount the utility has an opportunity to earn on its entire investment: distribution, transmission, and generation.

Q. Does the deadband have anything to do with the distribution of actual NVPC outcomes around a point NVPC forecast, whether done using PGE's MONET model or on an "expected value" basis?

A. No.

Q. Would using a distribution of actual NVPC outcomes derived through stochastic analysis support applying a deadband to ensure customers and the utility continue to bear cost of service risk?

A. No, I do not believe so. As I discussed above, the distribution from the model tells us nothing about the order in which those results might appear. Let's assume for a moment that all parties had confidence in the PA prototype stochastic model presented in PGE Exhibit 1803 and that the results of running that model for 2007 included a standard deviation of $55 million. The standard deviation means that about 2/3 of actual NVPC outcomes will be within $55 million more of the forecast average. Thus, some might consider this "normal." Let's also assume that the Commission adopts Staff's PCA mechanism. For the first five years in a row, actual NVPC are less than the forecast by the standard deviation. Customers have experienced over $275 million (using the UE 115 calculation for simplicity) of the NVPC cost of service risk they bear. The relevant question is not whether that is "normal" but whether it is a result that the Commission believes is consistent with its delegation of authority from the Legislature and sound regulatory policy.

Q. Does using a deadband increase the need for the Commission fairly to allocate the NVPC risk through how its sets the NVPC forecast?

A. Yes. To the extent that the regulatory framework reduces NVPC cost of service risk, it also reduces the importance of a precise allocation of the cost of service risk. Thus, our proposed regulatory framework leaves untouched the bias against PGE created by MONET's deterministic modeling of forecast NVPC because, with the 90-10 sharing, the data and modeling difficulties of creating an expected value NVPC far outweigh the gain. This trade-off is different with the deadbands that Staff or CUB propose, however. If the Commission adopts either of these proposals, based on what we know now, which we concede is not much, it should increase the NVPC forecast by some amount.

Q. Does CUB provide any analytical support for the asymmetric deadband its proposed PCA mechanism uses?

A. No. CUB reasons only that including actual NVPC in ratemaking should occur sooner if those actual NVPC are less than the forecast NVPC than if they are higher because this will produce "revenue neutrality." I address revenue neutrality below. CUB does not show that its formula works.

<u>3. Deadband "Precedent"</u>

Q. What "precedents" do the parties cite for their position that any NVPC regulatory framework for PGE must include a deadband based on PGE's earnings opportunity for its entire distribution, transmission and generation investment?

A. The parties generally cite: UM 995, UM 1071, and UE 165. See, e.g., CUB/200, Jenks-Brown/16. Some cite UM 1008/1009 as well but should not because the parties here all signed that stipulated result and agreed that it would not serve as precedent. In this docket, Staff and CUB add UE 137 to the list of "precedent." Id.; Staff/800, Galbraith/10.

Q. Do you consider UM 995 as precedent requiring that any automatic adjustment clause for a retail energy utility have a deadband?

A. No. UM 995 concerned a deferral, not an indefinite automatic adjustment clause. See Order No. 01-420 at page 28. We understand that order as a decision to grant a one-time deferral in an "extraordinary situation." The Commission balanced interests pursuant to ORS 756.040, as it must do whether the matter is a general rate case, a limited rate case, or some other proceeding affecting utilities and customers, and concluded: "We prefer Staff's mechanism to PacifiCorp's, however. PacifiCorp's model is structurally similar to Staff's but is more generous to the company. Staff's is more generous to ratepayers. We find that Staff's model balances the interests of the company and ratepayers in a more appropriate way." This decision does not discuss, let alone decide, how the Commission would structure an automatic adjustment to reflect in cost of service rates actual power costs on an ongoing basis.

Q. Did the outcome of UM 1071 require that PGE include a deadband in your Variance Tariff?

A. No. Again, as with UM 995, this was a deferral docket. As the Commission explained in Order No. 05-1261, the standard for recovery is stricter with a one-time deferral because there is no guarantee that the effects of offsetting events will be reflected in customer rates. Order No. 05-1261 at 9. ICNU's argument overlooks this distinction. ICNU/103, Falkenberg/27.

Q. Do any of the parties cite UM 445?

A. No. This 1991 matter is a deferral order and, thus, we do not consider it precedent any more than UM 995, UM 1071, or UM 1187. Nonetheless, it is notable that the parties exclude it because it contains what is, to our knowledge, the Commission's first decision distinguishing between "normal" and "extraordinary" costs for purposes of a utility deferral.

In UM 445, the Commission approved the deferral of 90% of the replacement costs (calculated on a comprehensive PCA-basis) stating that "the assignment of 10% of costs to PGE investors will create a financial incentive for PGE to minimize costs during the Trojan outage period, and:

> PGE would not customarily be compensated for "normal" variation in Trojan performance as they would affect power costs. Therefore, we suggest that assignment of 10% of power costs to PGE investors will generally reflect normal variation in plant operation. That is, PGE investors would assume the customary risk of "normal" variations in Trojan operations, which ratemaking actions would reflect the "extraordinary" variation occasioned by the steam generator problems."

UM 445, Order No. 91-1781, Appendix A at 6.

Q. How does Staff use UE 137 as precedent for a deadband?

A. Staff states that: "The lack of precedent for a deadband in an indefinite automatic adjustment mechanism is not a credible objection. In Docket No. UE 137, PGE included a deadband … in its proposal for an indefinite PCA mechanism." (Staff/800, Galbraith/10). First, we doubt that our actions or proposals establish "precedent" as that term is usually understood. Second, Staff neglects to provide the whole story about that docket.

In that docket, filed May 2002, PGE proposed some modifications to the one-year PCA approved on stipulation by the Commission in UE 115. This proposal included the deadband approach of the prior stipulated PCA, along with other important features of that stipulated mechanism, including an energy revenue adjustment. Staff's testimony does not explain, however, that PGE withdrew the UE 137 filing because:

> "PGE testified in UE-137 that we should collectively decide in advance how the risks and consequences of severe changes in net variable power costs should be shared between PGE and our customers. We still believe that. However, we do not believe that a decision reasonably acceptable to all parties is likely in UE-137. Our customers cannot accept PGE's proposal. PGE cannot accept Staff's proposal. PGE therefore believes that no PCA is preferable." (PGE Exhibit 1806)

Moreover, Staff does not acknowledge any change in circumstances between 2002 and 2007. In 2002, Sumas gas prices for 2003 were $3.59/mmbtu and projections were $2.69/mmbtu to $3.79/mmbtu over the 2003-2013 period (all figures nominal). In 2007, Sumas nominal gas prices are $8.56/mmbtu and the projections we are using in our current Integrated Resource Plan process range from $8.43/mmbtu in 2007, down to $5.21/mmbtu in 2012, then back up to $9.44/mmbtu in 2026 (all figures nominal). High gas prices increase the size of the NVPC cost of service risk by making unexpected output from our resources more valuable and unexpected loss of output more costly. Even if we once believed a deadband feasible under a PCA that included energy revenues, the consequences are higher for both PGE and our customers and we do not consider this earlier position "precedent" to be used as "evidence" against our current proposal.

Q. CUB cites UE 143 as precedent for a deadband (CUB/200, Brown-Jenks/16). Do you agree?

A. No. Docket UE 143 relates to the 15-month PCA the Commission approved on stipulation in UE 115. This stipulation is not "precedent" or "evidence" for the same reason as UE 137, they both relate to a stipulation which included other salient features, such as an energy revenue adjustment.

Q. Do you agree that Order No. 05-1261 requires that any tariff PGE might propose to address the differences between actual and assumed NVPC must include a deadband?

A. No, we do not, for two reasons. First, the Order states: "The inclusion of a deadband around expected power costs is <u>a reasonable way</u> to identify whether an event is unusual." Order No. 05-1261 at 9 (emphasis added). The parties imply that "a reasonable way" actually reads "the only reasonable way." That is not what the Order says.

Second, the Order describes a deadband around <u>expected</u> power costs. PGE did not have then (for 2005 and 2006, the years to which the stipulated SD-PCAM would have applied) and does not have now (for 2007) a forecast of NVPC that is "expected" as I described that concept in Section II. This design criterion appears to apply only when the Commission has used expected power costs for forecasting test year NVPC.

With regard to our second point, we note that Order No. 05-1261 repeats the Commission's conclusion from Docket UM 1071 that "hydro availability" is a "stochastic risk." Id. at page 8. We did not agree with that conclusion then and do not agree with it now to the extent that it implies that our NVPC forecast for any given year reflects and averages all possible combinations of hydro production and resultant power costs. Even if one believed that the 69 years of actual river flow information modeled into 69 outcomes of hydro production expressed all possible annual hydro production outcomes and the exact distribution with which they would occur over the next 69-year period, that would tell one little about the range or distribution of NVPC <u>outcomes</u> one could expect. These outcomes will depend on all of the other variables, including load, the operation or PGE's other resources, market power prices and market fuel prices.

When we objected in Docket UM 1071 that no evidence supported the Commission's conclusion regarding the "stochastic" nature of hydro production in the test year assumptions used to establish rates, the Commission chided us for not seeking an evidentiary hearing in that docket. This docket is an evidentiary proceeding and we renew our objection to the factual conclusion that the test year assumptions used by the Commission to set our rates express hydro production "stochastically." The PA report is the closest to a stochastic representation of expected value power costs, including treatment of hydro production as stochastic. Further, saying something is a "stochastic risk" when it has not been modeled stochastically does not tell us anything about the size or frequency of the risk or who bears it.

Q. Is there any other Oregon guidance on the issue of using a regulatory framework to reduce cost of service risk for costs that are significant and volatile?

A. Yes. From 1979 to 1989, PGE's regulatory framework included a comprehensive power cost adjustment clause under which PGE produced a new forecast of NVPC every quarter and shared variances between those forecasts and actual costs with customers on an 80-20 basis. See Order No. 79-830. We do not understand the basis for the claim in ICNU's testimony that "other than the UE 115, the Commission has never approved a comprehensive PCA for PGE." (ICNU/103, Falkenberg/40).

Oregon has also, for many years, used a regulatory framework very similar to what we are proposing to include actual purchased gas costs in LDC cost of service prices. As explained in our opening testimony (PGE/400 Lesh-Niman/39-40) PGE's NVPC are very similar to the gas costs of Oregon's LDCs – particularly Northwest Natural Gas Company (NNG). For example, using NNG's last test year in Docket No. UG 152 with this docket, NNG's cost of purchased gas was 57% of its overall revenue requirement compared to the 50% of revenue requirement comprised of NVPC for PGE. Although NNG has no production rate base, only about one-third of PGE's rate base is production-related.

It is particularly useful that the purchased gas cost adjustment clauses (PGAs) are ongoing mechanisms, rather than the recent deferrals to which the parties point as indications of "normal."

Q. Do the parties address your belief that PGAs provide useful information for designing a power cost regulatory framework for PGE?

A. Only CUB responds, arguing that "unlike a gas utility, an electric utility's rate base includes far more than its distribution plant. An electric utility's distribution system represents only a portion of the company's rate base, which also includes expensive generating plants . . . [and] an electric utility is paid a profit on its generating plants." (CUB/200, Jenks-Brown/10). CUB also argues that electric utilities are different because "while a gas utility is simply a price-taker on the gas market (and the Commission allows the gas utility to pass that price through, barring imprudence), electric utilities have the responsibility and the opportunity to optimize resource decisions. The inexactitude of cost recovery is an integral part of the regulatory incentive . . . " Id. at page 11.

Q. Do you agree with CUB's application of these distinctions?

A. No. First, with respect to generation rate base and our profit opportunity, we note that all of the deadbands and sharing tiers used or proposed recently reflect the electric utility's entire rate base, not just generation. Neither the parties nor the Commission have addressed why an electric utility's earnings opportunity related to distribution rate base should be at risk to its power supply function if a gas utility's is not at risk to its gas supply function.

Second, to the extent CUB's conclusion relies on the fact that generating plants are "expensive," CUB does not quantify this or show how it relates to PGE's generation. Of course, a significant portion of our resources are contractual and, thus, earn no return and several of these are the resources that create the greatest risk of assumed costs that do not match actual costs. For the remainder, another significant portion are at least half way through their useful lives, with depreciated original cost plant balances that are difficult to consider "expensive." Perhaps the distinction CUB offers made sense in the 1980s, when recently rate-based generating plants produced significant returns and cost-based power and fuel prices were low. It does not support punitive regulatory frameworks for electric utilities now, under today's actual circumstances.

I addressed in Section II CUB's belief that electric utilities bear the risk of operating cost outcomes that are less than optimal and that PGE's proposed Variance Tariff aligns customer and utility interests with respect to operational decisions. CUB presents no evidence that a 90-10 sharing does not adequately do this. The PGAs also use sharing to align utility and customer interests with respect to the variance component of the mechanisms. As we noted in PGE Exhibit 400, the variance in operating cost outcomes typically is much smaller for LDCs than electric utilities because LDCs do not have resource stacks with supplies having little to no variable cost (hydro and coal generation) as compared to the market. (PGE/400, Lesh-Niman/38-40).

Q. Exploring further the point that the parties' deadbands apply to PGE's entire investment base, while CUB argues that the difference between PGE and LDCs is PGE's earnings on its generation rate base, what is PGE's earnings opportunity on its various resources?

A. PGE's total 2007 unbundled generation rate base, including Port Westward, is $774.8 million. Even at PGE's filed cost of capital[5], the amount of generation earnings power that we would expect from test year ratemaking is approximately $46.6 million[6]. The generation earnings power is detailed in Table 1 below:

Table 1

Plant	Earnings Power
Boardman	$8.9 million
Colstrip	$6.4 million
Beaver/Coyote	$9.7 million
PGE Owned Hydro	$5.9 million
Port Westward	$15.7 million
Total	$46.6 million

Q. How does this earnings capability compare to the deadbands that Staff and CUB propose?

A. The total generation earnings power shown in Table 1 is on an after-tax basis. The comparable pre-tax amount is approximately $77 million. On a pre-tax basis, Staff and CUB's deadbands for actual power costs in excess of forecasted are approximately $22 million and $38 million, respectively, or 29% and 49% of pre-tax generation earnings power, respectively.

Q. Does Senate Bill 408 change this analysis?

[5] PGE filed for 10.75% Return on Equity and a 55.96% Equity share in the capital structure. Staff, CUB, and ICNU all support a lower ROE and Equity share in the capital structure.
[6] At Staff's supported ROE of 9.30% and 48.5% Equity share in the capital structure, the earnings power of PGE's generation rate base would fall to $34.9 million ($774.8 million * 48.5% * 9.30%)

A. Yes. As I discuss in Section V, the tax true-up of SB 408 changes this analysis. Under SB 408, for Staff and CUB's deadbands to have the same effect on PGE, they would have to be reduced from $22 million and $38 million, to $15 million and $25 million. CUB seems to understand this SB 408 effect. (CUB/200 Jenks-Brown/23). Staff does not mention it. Absent recognition of SB 408's effects, the Staff deadband of $22 million is comparable to the after-tax generation earnings power of approximately $47 million. Unless the Commission considers SB 408 in deciding on a NVPC regulatory framework for PGE, a deadband the size Staff proposes would take almost half of PGE's total earnings capability for generation investment.

Q. Can you provide an example that relates the earnings power of PGE's assets to the NVPC cost of service risk PGE bears without a PCA mechanism?

A. Yes. Exhibit 1917 shows that an unexpected outage of only 18 days duration would entirely absorb the earnings power of the Boardman asset ($8.9 million). Similarly, an unexpected outage of only 15 days at Colstrip would entirely absorb its earnings power ($6.4 million). These examples assume market power prices of approximately $68/MWh, consistent with PGE's most recent MONET update in this proceeding.

Q. Would these examples be even more dramatic for PGE-owned hydro and the Mid-C contracts?

A. Yes. The variable cost of these resources is even less than that of Colstrip and Boardman. And, of course, the Mid-C contracts have no earnings potential at all.

Q. Are these examples based on the entire return to shareholders, or simply on the "premium" above the cost of debt that shareholders require to absorb earnings fluctuations?

A. These examples are based on the entire return, or 10.75%, in PGE's March filing in this docket. The debt rate that is consistent with this 10.75% equity return is 6.83%, meaning that difference, 3.92%, is the "premium" that shareholders require over a debt return to accept the risks of holding equity rather than debt. Using the risk premium, rather than the entire return, would further emphasize the fact that the NVPC cost of service risk PGE's shareholders bear is large relative to their investment. For example, a Boardman outage of only seven days would entirely absorb the associated risk premium that shareholders receive for that plant.

4. Other States' NVPC Regulatory Frameworks

Q. Do the regulatory frameworks other states have adopted for electric utility power costs provide guidance for deciding how Oregon should address the NVPC cost of service risk of PGE's system?

A. Yes, we believe so. That is why we asked NERA to produce the report presented as PGE Exhibit 401.

Q. Did the parties address this report?

A. Only ICNU. See ICNU/103, Falkenberg/38 – 39 and 44-45. CUB and Staff make no comment on what other states consider to be "normal" risk that an electric utility should bear.

ICNU's comments note that Idaho and Arizona have both adopted power cost regulatory frameworks that base prices on actual power costs with a 90-10 sharing of the difference between the assumed and actual power costs. Id. at page 38. ICNU asserts, however, that Colorado's sharing percentages also come with a deadband. Id. However, they provide no support for this assertion. Attached as Exhibit 1807 are the relevant pages excerpted from the Colorado Public Utility Commission order. They clearly demonstrate that the mechanism has no deadband, only sharing tiers designed to ensure that the variance between assumed and actual power costs the utility absorbed was no more than $11.25 million, and total variance amounts in excess of $30 million are 100% allocated to customers.

The ICNU testimony argues that the stipulated automatic power cost adjustment clause that the Washington Utilities and Transportation Commission (WUTC) recently adopted for Avista included a deadband, as does the one currently in place for Puget Sound Energy (PSE) (although the ICNU testimony does not explain other features of the mechanism, including the three-year total cap on losses to PSE of $40 million). Id. at page 39. Washington is but one of the numerous states covered by the NERA report. We do not disagree that the WUTC has approved stipulated mechanisms that include a deadband. This is by no means a majority view, however. See PGE Exhibit 400 at pages 40-44.

Q. Does ICNU suggest that the Avista mechanism's deadband can be understood as a percentage of NVPC, rather than the "normal" risk a utility should bear, expressed as a certain number of basis points of its net income opportunity?

A. Yes, surprisingly. Of all the ways that the parties and the Commission have discussed the use of a deadband, a percentage of the affected cost has never been one. In reality, Avista's situation is much closer to PGE's with respect to the factors the parties usually suggest pertain to a deadband.

To look at this comparably, we combined Avista's Oregon and Idaho operations (Idaho bases Avista's prices on actual power costs with a 90-10 sharing of the variance between assumed and actual) and scaled the numbers to PGE's rate base and capital structure.

Assuming one thought that “normal” risk should apply to an electric utility’s entire rate base, not just production, and PGE’s filed capital structure, the comparable numbers for PGE would be a deadband of $9.4 million and 50-50 sharing of an additional $14.2 million. This is before adjusting for the effects of the SB 408 tax true-up of course. Doing so would make the deadband $5.7 million and the 50-50 sharing an additional $8.6 million. Using only production rate base as the relevant factor in assessing “normal,” the deadband and 50-50 sharing tier would be $4.6 million and $6.9 million, after adjusting for the tax true-up of SB 408.[7]

The ICNU testimony provides no evidence for the assertion about the amortization period for fuel-cost recovery in Georgia, so it was not possible to verify. Nonetheless, whether Georgia sets retail electric prices on actual power costs recovered over three months or longer periods as necessary, for purposes of this case, the important comparison is that Georgia sets electric prices based on actual power costs, not assumed power costs. (ICNU/103, Falkenberg/44).

Last, ICNU notes yet a further example of the appropriateness of setting retail electric prices for cost of service utilities based on actual power costs: traditionally-regulated utilities in Texas. Id. That the NERA study overlooked these utilities is less important than adding them to the overwhelming majority of traditional cost of service electric utilities regulated in such a fashion.

B. Revenue Neutrality

Q. Is the Order No. 05-1261 design criterion regarding revenue neutrality entirely clear?

[7] The details of these calculations are contained in the work papers to PGE Exhibit 1900.

A. No. Staff has discussed this criterion in terms of requiring that a PCA mechanism not bias the overall expected level of recovery. CUB has applied this criterion in terms of attempting to achieve a match of collections and credits through an asymmetric deadband that includes actual NVPC costs in cost of service prices sooner if those actual NVPC are lower than forecasted than if the actual NVPC are higher than forecasted.

Q. What is your understanding of this criterion and does PGE's proposed NVPC regulatory framework satisfy this?

A. Our understanding of the revenue neutrality design criterion is that the Commission will allocate NVPC cost of service risk as neutrally as possible (given the tools available and acceptable for forecasting purposes) and that any PCA mechanism accompanying the forecast should not change this allocation. As I explained in Section III, the Annual Update tariff helps ensure that the Commission's allocation of NVPC cost of service risk is as neutral as possible by including within the forecast actual information relating to the coming year, such as actual fuel, power and transmission contracts. PGE's proposed Variance Tariff does not change the allocation of risk resulting from the NVPC forecast because it includes actual NVPC in cost of service prices on an even basis whether those actual costs are lower or higher than the forecast.

Q. Did Staff address revenue neutrality explicitly in presenting its proposed PCA mechanism?

A. No. One could infer, however, that Staff's understanding is similar to ours because Staff's proposed PCA mechanism also includes actual NVPC in cost of service prices on an even basis, albeit after application of an even deadband around the forecast NVPC.

Q. Is the interpretation of the revenue neutrality criterion expressed by CUB and reflected in CUB's asymmetric deadband feasible?

A. No. It is not feasible either on an "actual" basis or on an expected basis.

On an actual basis, no one can know whether collections under a PCA mechanism will "match" credits until, at some future point, one looks back to check. Given the randomness of the variables – particularly precipitation – that affect PGE's NVPC, it is nonsensical to speculate let alone require that such equality occur over any particular past period one might choose – five years, ten years, or longer.

The situation does not improve if one attempts this on an "expected" basis. I have already discussed the limitations of "expected value power cost modeling." Theoretically, if PGE were able to forecast NVPC on an "expected value" basis, this forecast would evenly share, for that forecast, the probability that actual NVPC would be higher or lower. The variance for that year would be what the variance would be; it is impossible to predict whether it would be a collection or refund. If nothing changed – not one input (fuel prices, plant availability, load, etc.) in the following year, PGE would create another forecast NVPC on an "expected value" basis and this forecast also would evenly share, for that forecast, the probability that actual NVPC would be higher or lower. The variance for that year also would be a collection or refund. If this continued for enough years – and no one has any idea how many years that would be but, typically, a "stochastic analysis" uses at least 1000 "games" of playing the interrelationships against each other – one could expect the amounts collected to equal the amounts refunded. This is unrealistic because the inputs always change, year to year and some years, dramatically.

Q. Is CUB suggesting that customers should not have to experience the actual "costs" that may result from some of PGE's resources because those costs may exceed the "benefits" the resources are capable of producing?

A. Perhaps. As I discussed in Section II, the parties at times imply a desire to separate the historic fixed costs of PGE"s resources from the variable costs of power those resources produce. Our Mid-C contracts have very low fixed costs and we are delighted to have them. But the power those contracts enable us to obtain is variable and, thus, the cost associated with the portion of PGE's resource portfolio those contracts provide is variable as well. The total cost is what the total cost is. Excusing customers from that total cost on the basis that it is uncertain is poor regulatory policy and poor economics.

Q. Did CUB attempt to demonstrate that its proposed PCA mechanism would satisfy its interpretation of the revenue neutrality design criterion?

A. No.

C. Earnings Test

Q. What earnings test did the Commission indicate it considered as a design criterion for the SD-PCAM it considered in Order No. 05-1261?

A. The Commission explained this criterion as follows: if PGE's actual NVPC were lower than the forecasted test year NVPC used to set cost of service prices, PGE would refund the difference to customers only to the extent that making such a refund would lower PGE's earnings for the year to 100 basis points above the return on common equity last authorized by the Commission. Conversely, if PGE's actual NVPC were higher than the forecasted test year NVPC used to set cost of service prices, PGE would collect the difference from customers only to the extent that making such a collection would bring PGE's earnings for the year to 100 basis points below the return on common equity last authorized by the Commission.

Q. How does this design criterion affect the allocation of risk between PGE and customers?

A. It doesn't. As we explained above, it is the baseline forecasted NVPC that allocates the risk that forecasted cost of service will vary from actual cost of service.

Q. What does this design criterion accomplish in terms of risk?

A. It restores some of the risk that a power cost adjustment mechanism otherwise would reduce. In other words, it decreases the probability for both our customers and PGE that our cost of service prices for on-demand retail electric service will reflect actual cost of service.

Q. Do Staff and CUB's proposed power cost adjustment mechanisms use this "earnings test" from Order No. 05-1261?

A. Yes. Both parties apply this. See Staff/800, Galbraith/15 and CUB/200, Jenks-Brown/22.

Q. Does either party reply to the concerns you raised regarding this earnings test in PGE Exhibit 400?

A. Only Staff responds to our concerns and then only by suggesting that, because this is a general rate case, the Commission will consider all risk allocations in deciding the case. (Staff/800, Galbraith/17-18).

Q. Does Staff's reply testimony on cost of capital indicate recognition of the effects of this earnings test?

A. No.

Q. Is this earnings test consistent with the regulatory framework the Commission applies to the risk that actual cost of natural gas will vary from the forecasted cost of natural gas for LDCs and their customers?

A. No. The Commission's regulatory framework for LDCs significantly reduces the risk to the utilities and their customers of gaps between forecasted and actual purchased gas cost by requiring an updated forecast every year and adjusting this for the actual incurred cost after-the-fact, with sharing percentages that vary among the LDCs. In that regulatory framework, the Commission applies an earnings test to the utility's overall results to ensure that the handling of this cost of service element does not result in overall earnings that are unreasonable. What is "unreasonable" varies from between 200 and 300 basis points above the utility's authorized return on common equity[8].

Q. Has any party articulated a reason why electricity customers and electric utilities should bear greater risk of cost of service variances than gas customers and gas utilities?

A. No.

Q. What is PGE's position regarding this design criterion from Order No. 05-1261?

A. We urge the Commission to discard this design criterion and adopt the earnings test we proposed for the Variance and Annual Update tariff regulatory framework. This earnings

[8] OAR 860-022-0070 allows gas utilities to forgo an earnings test for PGA amounts if shareholders absorb at least 33% of gas cost changes. In recent years, Northwest Natural and Cascade have elected to absorb 33% and hence they have not been subject to an earnings test. Should Northwest Natural elect to absorb less than 33% of gas cost variation, the earnings test sharing mechanism would be based on Order 99-272 which called for a 300 basis point band above the authorized ROE before customer sharing of "excess" earnings. Cascade's earnings sharing mechanism would only begin with an ROE that is greater than 710 basis points above the risk free rate (See Order 98-543). Avista's customers currently absorb 90% of gas cost changes and hence the company is subject to an earnings test. The earnings test sharing mechanism would only begin with an ROE greater than 200 basis points above the authorized ROE prior to customer sharing (See Order 05-1053).

test will ensure that the entire regulatory framework used by the Commission, including that for NVPC, does not result in unreasonable earnings.

V. Variance Tariff Design Issues

Q. To what Variance Tariff design issues will this section of your testimony respond?

A. In this section, I address issues the parties raise regarding treatment, application of the mechanism to direct access customers, the process and content of review, and alleged incentives. I also address SB 408. PGE Exhibit 1900, Section II addressed the alternative proposals for how any PCA mechanism should handle load variations.

A. Direct Access Customers

Q. What position do the parties take on whether the Variance Tariff should apply to those customers that are using one of the temporary direct access options (as opposed to the long-term schedule 483 opt-out)?

A. Staff recommends that the Commission exclude all direct access customers from the Variance Tariff or similar mechanism, reasoning that to do otherwise would deny these customers the benefit of disconnecting their annual energy expense from regulated cost-of-service ratemaking. (Staff/800, Galbraith/18).

Q. Do you agree?

A. No, but we acknowledge that it is a matter of judgment. The difficulty is that these customers have only partly disconnected themselves from cost-of-service ratemaking; they receive from cost-of-service customers a transition credit representing the “value” of the direct access customer’s “share” of PGE’s resources. We set that “value” in the same manner as we forecast test year NVPC – with many assumptions. In essence, these temporary direct access and market-based rate customers shift their risk that actual NVPC will be less than the forecasted NVPC to the remaining cost-of-service customers.

Q. Is there a practical problem with Staff’s recommendation?

A. Yes, because these customers can switch back-and-forth between cost of service and the direct access/market-based rate options every year. Thus, PGE could not simply charge these customers the cost-of-service rate – which, at any time, may include the net of credits and charges under the Variance Tariff – in any particular year that the customers choose cost of service. We will need to associate a Variance Tariff charge or credit with a vintage year of cost-of-service use and track which customers receive what vintage. We also will need to pro-rate somehow for customers that choose a partial year of direct access service under the new quarterly option. This could get particularly complicated if the Commission decided to spread the credits or charges of a given year over multiple years. Creating the systems and quality control to do this will be neither easy, cheap, nor foolproof. At a minimum, we can expect that billing errors will occur.

B. Scope and Timing of Review

Q. Did PGE propose a process for Commission review of calculations under the Variance Tariff?

A. Yes, we did. We proposed to make a filing in June that would include the work papers that provide for the variance amount, an earnings test, and proposed rate adjustments to be effective at the beginning of the next calendar year[9]. That filing would initiate a Commission process that would include the ability of parties to raise prudence issues that impacted the variance calculation.

Q. Does ICNU challenge the time period proposed for this process as insufficient to explore the prudence of PGE's actions or check for accounting inaccuracy?

A. Yes. (ICNU/103, Falkenberg/42-43).

[9] See PGE/400, Lesh-Niman/50-51 and PGE/1302, Kuns-Cody/95.

Q. Is PGE amenable to any period the Commission finds necessary to provide parties adequate time to review and contest, if necessary, PGE's filings?

A. Yes.

Q. Is PGE also willing to accept rules or filing requirements that enable parties easily to verify PGE's accounting entries?

A. Yes. ICNU charges that we may engage in "gaming" accounting entries. ICNU/103, Falkenberg/43. Because ICNU's witness provides no examples of this, by PGE or any other utility, we are unsure exactly what he is referring to. If ICNU has suggestions for rules or filing requirements that would assist parties in reviewing PGE's filings under the tariff, however, we are certainly willing to consider them.

Q. Do you agree with ICNU that the Variance Tariff would shift the burden to parties to show that PGE was imprudent?

A. No. The burden of proof remains with PGE. Whether the process will be as familiar to parties as challenging PGE's prudence in a general rate case, we do not know. We disagree, however, with any suggestion that a regulatory framework must consume very little time.

Q. Does CUB's testimony suggest that PGE was unclear with respect to the prudence review you envision will occur under the Variance Tariff?

A. Yes. CUB asks: "Is the Company proposing that its actions that would be captured by this mechanism be subject to a prudence review, or is the Company suggesting we should simply assume the Company's actions to be prudent?" (CUB/200, Jenks-Brown/19). Our proposal is that the parties be free to challenge any aspect of the matters covered by the Variance Tariff. Indeed, parties would probably be free to do so even if it was not our proposal. Moreover, we indicated that, in particular, parties may want to focus on decisions or actions

PGE may have made prior to the year in question that the parties believe may have affected actual NVPC during that year. (PGE/400, Lesh-Niman/51). With respect to operational decisions during the year, we do believe that the sharing component of the Variance Tariff should give parties some comfort that we are unlikely to have acted against our financial interests. We did not mean to imply any limit to parties' review.

C. Effect of the Variance Tariff on PGE's "Incentives"

Q. Does ICNU express concern that the Variance Tariff may weaken PGE's incentives to acquire least-cost resources or act prudently and efficiently?

A. Yes. See ICNU/103, Falkenberg/34-36. ICNU suggests that PGE will:

- Purchase wholesale energy rather than increasing or even retaining investment in generation
- Minimize capital investment in existing generation and transmission
- Choose resources whose costs are eligible for recovery through the Variance Tariff, even if those are not least cost
- Fail to challenge an unfavorable coal contract or sue a supplier over a contract default
- Fail to maintain adequate coal inventories
- Fail to maintain generating plants
- Be insensitive to the cost of power

Q. Does ICNU provide any examples or evidence in support of these alleged ill effects?

A. No. These all are presented solely as matters of the witness' opinion.

Q. Do you believe that the concerns of ICNU's witness are well-founded?

A. No. None of them are well-founded.

The concerns least well-founded are those relating to the effect of the Variance Tariff on the future resources we might choose. ICNU has the incentives exactly reversed: without a reasonable NVPC regulatory framework, PGE's incentive is to obtain resources whose price is as close as possible to market, such as annual forward contracts. These minimize the size and likelihood of significant variances from forecasted costs. The least attractive resources are our vintage Mid-C hydro contracts and our coal generating plants. Even a new wind generating facility is unattractive under a regulatory framework that does not minimize the risk that forecasted NVPC will vary from actual NVPC. Moreover, PGE's future resource actions are the subject of intense review through the IRP process, in which ICNU participates. We are unlikely to take any long-term resource action that does not go through this process.

Most would marvel at the claim that a power cost adjustment causes a utility to avoid investment in new or existing generation or transmission. The concern usually is that we have too many incentives for investment, not that a given regulatory scheme creates too few.

Almost equally unlikely is the claim that we will somehow choose resources that are eligible for recovery under the Variance Tariff but avoid resources that would require a general rate case for inclusion in our cost of service prices. We note, first, that the Annual Update component of our proposed regulatory framework mitigates this concern because only new owned generating plants would require a general rate case. If an acknowledged IRP Action Plan includes resources that are not eligible for the Variance Tariff, then we will surely file a new rate case in time to recover the costs of these acknowledged resources, including owned generation. The lead time involved in the latter makes this relatively easy to do. Second, ICNU discounts the sharing component of our Variance Tariff. Whatever short-term risk we take in an attempt to achieve the lowest possible NVPC, we will share in the result of that risk with customers.

The sharing feature also addresses the remaining alleged disincentives. We are unlikely to want to bear 10% of the effects of poor decisions around adequate coal inventories, plant maintenance, overall power costs, or NVPC-related litigation.

D. SB 408 Effects

Q. Does the Commission's interim order in Docket No. AR 499 cause you concern about the Variance Tariff as you proposed it?

A. Yes, this Order preliminarily adopts the interpretation of SB 408 under which the income tax true-up includes differences caused solely because a utility incurred a different cost of service for on-demand retail electricity service than it forecasted during a test year used to set prices. As we highlighted for the Commission in Docket No. AR 499, the effect of interpreting SB 408 in this way is:

> When, in the course of fulfilling its obligation to serve, a utility incurs fewer expenses than the Commission assumed it would incur when it established rates for the utility's services, the automatic adjustment clause under SB 408 will surcharge customers and increase the utility's earnings on these utility services for the year in question.
>
> When, in the course of fulfilling its obligation to serve, a utility incurs more expenses than the Commission assumed it would incur when it established rates for the utility's services, the automatic adjustment clause under SB 408 will require the utility to make a refund to customers and decrease the utility's earnings on these utility services for the year in question. (PGE Reply Comments on Straw Proposals, filed May 19, 2006).

In our opinion, this interpretation makes adoption of the Variance Tariff as we proposed it even more critical but does call into question the 90-10 sharing component. If actual NVPC are less than forecasted NVPC, we will return 90% of the difference to customers but customers will owe us the tax effects of the 10% we keep. Conversely, if actual NVPC are higher than forecasted, we will recover 90% of the difference from customers but will owe customers the tax effects of the 10% we absorbed. We are unsure if the Commission should adjust the sharing percentages to minimize this effect but we wanted to note it.

Q. Is it clearer that the Commission must make adjustments for SB 408 if it adopts either the Staff or CUB proposal?

A. Yes. CUB acknowledges this, which we appreciate. (CUB/200, Jenks-Brown/23).

Q. What is the effect of SB 408 on the risk you discussed in Section I?

A. SB 408 increases the risk that utilities and customers already shared that the forecast used to set cost of service rates would, in actuality, be different than the actual cost of service incurred.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1801	Referenced Galbraith Deposition Pages
1802	Referenced Testimony from UE 165, PGE/300, Niman-Tinker/17-32
1803	PA Consulting Report
1804	UE 165 PGE Cover Letter for PA Consulting Report
1805	Referenced Testimony from UE 149, PGE/200, Lobdell/3-8
1806	PGE Letter withdrawing UE 137 Filing
1807	Referenced Pages from C03-0670 (Colorado)

The period we're looking at for calculating expected value is the forecast test year.
A (Nods head.)
Q I assume the recovery period -- is that a yes? Excuse me, you nodded your head. And I thought you'd nodded your head yes.
A Was it a question? I assume it was.
Q I should have said question mark, excuse me. I'll try to phrase that better.
Assume that was the question. Let me rephrase it.
Is the recovery period that you're talking about for expected power costs the forecast test year?
A In most instances, yes. In a general rate case you look at a future test period and you're setting rates for that future test period, acknowledging that rates may have been in effect for something longer than that single test year.
Q Okay. And can you explain to me how a PCA mechanism could bias the expected level of power cost recovery in your words?
A A one-sided PCA mechanism that only provided recovery for higher power costs and didn't provide refunds for lower power costs, that type of one-sided mechanism would bias the overall expected level of

recovery (nods head).
Q Wouldn't that depend upon whether you had -- wouldn't bias depend upon the actual circumstances that exist when you apply the PCA?
A Again, when I'm talking about the PCA mechanism biasing recovery, I'm talking on an expected basis, on an expected going-forward basis.
If the mechanism only triggered when costs increased and didn't trigger when costs decreased, even assuming there was equal likelihood of the cost increases and cost decreases, you'd get, you'd get a different expected recovery than you would if you just set power costs on normalized rate-making principles.
Q Did you have any other bias in mind when you wrote that sentence?
A No, it's simply the idea that on an expected going-forward basis the mechanism should be neutral.
Q And when you use the phrase "should be neutral," do you mean should be neutral with respect to both companies -- both the company and its customers?
A Yes.
Q Okay. Would you please turn to page 9? And I'm looking at the first line of your testimony on that page. The first sentence reads, quote, "A

fundamental issue in this docket is the amount of risk reduction, or conversely earnings stability, that is reasonable to achieve through implementation of a PCA mechanism."

Do you see that sentence?

A Yes.

Q What risk are you talking about in the first phrase in that sentence?

A Well, it's a two-part risk. It's the risk that power costs will deviate from the level that's included in rates, and the impact of that power cost deviation on the utility's earnings.

Q I notice in the next sentence you refer to PCA mechanisms used to protect the company from extreme fluctuations in NVPC. Is it your view that only the utility has a risk with respect to variations from expected level and the impact of those variations?

A Could you restate that, please?

Q Is it your view that it is only the company that is at risk with respect to variations from expected power costs and the impact of those variations?

A No, that's not my view.

Q Would the customers also have a similar risk?

A Yes, customers have a similar risk.

Q In the first sentence again on page 9, after you say "the amount of risk reduction," then you add, "or conversely earnings stability."

Is that meant to refer to earnings stability with respect to both customers and the utility, or just one of those two?

A The important thing to remember here is is that in -- a PCA mechanism allocates risk between shareholders and customers. And so the use of the phrase "risk reduction" here is pointing out that a risk reduction for shareholders is a -- is a risk increase for customers.

And so I phrased the first sentence here from the perspective of a risk reduction for shareholders, or conversely, an improvement in their -- in the stability of shareholder earnings.

There is a flip side to that first -- that first sentence, which would be: from the customer perspective.

Q Okay. You also refer to PCA mechanisms used to protect the company from extreme fluctuations in NVPC. What are extreme fluctuations in NVPC?

A Well, in past testimony -- and you see some of that testimony referenced at the end of that paragraph -- Staff has argued that an extreme fluctuation in net variable power costs would be roughly equivalent to 250 basis points of net variable power costs.

At the same time, in those previous proceedings, Staff has indicated that this is a matter of judgment, and that it would be important to look at the distribution of net variable power costs to determine that.

MS. ANDRUS: Can I have a moment?

MR. MORGAN: Sure.

(Off-the-record discussion)

THE WITNESS: So Ms. Andrus tells me that I made a misstatement there, that in previous cases Staff has argued that it would be -- an extreme fluctuation would be equivalent to 250 basis points of return on equity, ROE, not 250 basis points of net variable power costs, is I think what I said. So with that correction, I think I'm good.

BY MR. MORGAN:

Q That's fine, I was gonna ask you that. I thought that was probably what you meant.

A Okay.

Q Tell me what -- how the concept of an extreme fluctuation in NVPC has any relationship at all to

250 basis points of return on equity.

A Well, in -- the 250 basis points of return-on-equity standard I think was first put forward in docket UM 995 by Staff. And it represented an opinion that that was the level of variation in costs that a utility would be willing to absorb without coming to the Commission and filing a rate case.

Although I think I'm stating that accurately, I'm not stating it exactly as it was stated in that docket, but -- and so that's where -- that's the source of that opinion.

Q So does that mean that the real test is how painful the impact is to the utility, not what the fluctuation in NVPC is?

A I don't know how to answer that question. Restate it, and I'll see if I can --

Q Let me set a premise. You referenced that -- and if I mischaracterize your prior testimony, please let me know.

I thought I heard you say that in prior testimony Staff had determined that a 250-basis-point reduction in ROE was probably the type of reduction a company -- a utility could withstand without filing a rate case.

Is that a fairly accurate rephrasing of what you said?

A I believe that's an accurate phrasing of Staff's position in docket UM 995 and other deferral dockets, yes (nods head).

Q Now, doesn't that prior testimony of yours focus, really, on the impact of cost changes on the utility, not whether fluctuations in NVPC are extreme or not?

A I think it's a combined focus. I think the two things, to a certain extent, go hand and hand. That -- in other words, that if there was an NVPC fluctuation that resulted in -- or that was equivalent to 250 basis points of ROE, that it would be both an extreme fluctuation and be at the point where it was starting to cause financial impact.

Q Would the impact that you're referring to on the utility vary, depending upon the size of the utility's invested equity?

MS. ANDRUS: I'll ask a clar- -- object to the vagueness of the question, would the impact vary. It's not clear what you mean by would the impact vary.

BY MR. MORGAN:

Q Would the dollar value of a 250-basis-point

point reduction in ROE depend upon the rate base and earning potential of a particular utility?
A Yes.
Q Would you then propose to modify your view that a 250-basis-point reduction represents an extreme fluctuation in NVPC, depending upon the relative size and earning capacity of a utility?
A Would I -- you're gonna have to -- I don't know that I would revise the position; there's other considerations.
Q Would extreme -- would your view of what constitutes an extreme fluctuation change, depending upon the size of the utility?
A My view of what an extreme fluctuation is depends on the distribution of a utility's net variable power cost. And I think when we sort of originally started discussing this paragraph, I indicated that in this previous testimony Staff has been interested in trying to develop that distribution of power costs and look at that distribution of power costs; we haven't focused solely on the 250-basis-point standard.
Q Now, what do you mean when you say, quote, "distribution of power costs"?
A The frequency distribution of net variable

power costs for a test period.

Q This would be an excellent time for you to educate me. What do you mean when you say the "frequency distribution" for a test period of net variable power costs?

A Well, in previous testimony Staff has recommended the use of stochastic power cost modeling to develop a representative distribution of power costs for the test period, the idea being that you make, for example, a thousand Monte Carlo simulations of what power costs for the test period will be, and you look at the distribution of those power-cost levels for the test period.

Q And has Staff done, that in this case?

A No.

Q Has Staff done that in any other case?

A No.

Q So if you haven't done it, how would you know that that distribution had any relationship to, quote, extreme fluctuations?

A I'm simply saying that conceptually that's how you would, would look to determine what level of power cost deviation represented an extreme fluctuation in NVPC.

Q Would it be true, then, that without

stochastic power cost modeling we wouldn't be able to answer that question.
A No, not necessarily.
Q How would we answer that question, without stochastic modeling?
A Using judgment, as was done in docket UM 995, and using the 250 basis points of ROE standard.
Q And is that the standard that you're also using in your Testimony in this docket?
A No.
Q Okay, so you're saying that --
A Staff does not recommend a deadband of 250 basis points of ROE in this docket.
Q Let me ask a slightly different question. In proposing the deadband that Staff has proposed in this docket, are you basing that proposal on your judgment, rather than a distribution of expected power costs over a future test year that would be produced by stochastic modeling?
A So on page 16 of Staff 800, the first full Q and A there, discusses Staff's recommended power cost deadband and the reasons why we recommend it.
Q And is it fair to say that the basis of your recommendation is your judgment?
A Well, I, you know, I think the Q and A speaks

referring to the power cost variation from levels reflected in rates.

Q Okay. And is it because PGE's annual variance mechanism lacks a deadband that you think it shifts nearly all of PGE's power cost risk to the customers?

A That, in combination with the fact that the sharing percentage for power cost deviations is 90 percent. In other words, customers bear 90 percent of all power cost deviations.

Q Do the customers of the utility have a similar power cost risk to the one you referred to here?

A Yes.

Q And therefore, does the absence of a deadband and a 90/10 sharing as proposed by PGE shift all of the customers' power cost risk to PGE in the same way you've said that it shifts all of PGE's power cost risk to the customers?

A Well, the shifting needs to be compared to some baseline level of risk allocation. The baseline level of risk allocation, or the traditional level of risk allocation, is that between rate cases the utility bears the -- both the higher costs and the lower costs.

And so compared to that baseline, PGE's proposal shifts risks to customers.

Q Would it be accurate to say that PGE's proposed mechanism would share reductions in power costs 90/10 with customers?

A It would be accurate to say that. But as I just indicated, there's a baseline level of risk-allocation here, or sharing; and the traditional baseline level is that the utility bears 100 percent of net variable power cost variation.

PGE's proposal is to flip that around and have customers bear 90 percent of deviations.

Q Okay. Does a sharing mechanism, such as PGE's proposed 90/10 sharing mechanism, accomplish the same thing as a deadband?

A No.

Q Is that because it provides for sharing from day one as opposed to sharing after you get to a deadband?

A I would state that slightly differently. I would say that it's because a deadband excludes a reasonable range of variation from triggering the PCA mechanism; whereas PGE's proposed mechanism does not exclude a reasonable range. The mechanism triggers all the time.

Q Are you aware of what PGE's power cost variations from forecast have been in the last four years?
A Not specifically; in general, yes.
Q Did those actual valuations factor into your proposal for a 150-basis-point deadband?
A Again, I think I stated what figured in our considerations of proposing a 150-basis-point deadband.
Q And among the items listed on page 16, I don't find an analysis of PGE's past power cost variations from forecast power costs.
A That's right. That's correct.
Q Okay, thank you. A more general question for you, Mr. Galbraith: Does your proposal for a deadband and sharing mechanism take the effects of Senate Bill 408 into account?
A No.
Q Okay. Would you turn to page 11. And I'm looking at the question and answer beginning on line 13 and following over to the top of page 12. And here you're talking about allocation of power cost risk and management of risk.
Could you tell me which of the factors that drive variation of power cost PGE has control over?

A I'm not sure it has complete control over -- over any of the factors that drive variations of power costs. If it did, I assume there would be no variations.

Q Well, does it control load?

A Not completely.

Q Does it control weather?

A No.

Q Does it control market price?

A No.

Q Let's go back to load. When you say it doesn't control load completely, what do you mean by that? In what way -- let me stop there and simply ask in what way does PGE control load?

A Well, PGE has programs to -- again, the point here is being there's a difference -- there's a distinction, that, I think, is caused in this Q and A between control -- controlling these factors and managing the impacts of these factors.

And what I've suggested in this Q and A is that PGE has -- although it has little control over many of these factors, it has the ability to manage the impact of these factors.

And so, for example, load, although PGE doesn't control load, it does have programs that allow things and lost track of what it was.

Q I will try to restate that.

A Yeah.

(Previous question read by reporter)

THE WITNESS: Well, what I would say is the optionality, the flexibility, of generating resources, is important. On the other hand, low-cost base-load generation is nice as well.

BY MR. MORGAN:

Q Would Mr. Wordley's proposal to essentially give customers credit for what he views as the extrinsic value inherent in the optionality of PGE's thermal plants transfer all of the financial value in that optionality from PGE to its customers?

A Seems to me that's a question that should be asked of Mr. Wordley.

Q Then I will.

Would you turn to page 13? And I'm looking at the table that you've prepared, starting with line 4 of that page, down through line 16 of that page.

At the beginning of line 12 you make this statement: "Neither of these time series exhibits the highly dynamic year-to-year change that would necessitate an Annual Update mechanism."

What percent changes from year to year in these time series would be necessary before you declared those changes dynamic?

A I didn't have a particular percentage change from year to year in mind when I wrote -- when I made that statement.

Q What percent changes would be highly dynamic?

A I didn't make that determination either.

Q Did you actually calculate the percent changes in those time series?

A No.

Q The last sentence beginning at line 14 of that carryover Q and A, say -- quote, "These patterns of variation can be easily handled by a power cost framework that includes a retrospective automatic adjustment clause and periodic general rate case."

How periodic should a rate case be to easily handle the variations in the power cost framework you're referring to?

A Well, I believe that's a determination for their utility management to make. If based on its advanced purchasing it sees that there's gonna be a dramatic change from what is -- from the power costs that are included in its rates, then it would make the decision, after considering other factors, to file for a general rate case.

MR. MORGAN: Thank you. Mr. Galbraith, just one and maybe just a couple of more questions on one topic.

THE WITNESS: Okay.

BY MR. MORGAN:

Q In preparing your -- in preparing Staff's proposed power cost framework, including deadband -- or power cost deadband, sharing mechanism, and earnings deadband, did you consult with Staff's cost-of-capital witnesses with respect to that framework?

A I certainly had discussions with Bryan Conway about PCA mechanisms; I've been talking with Bryan about them for two or three years now. So in that respect I guess the answer is yes.

Q Did Brian, in those discussions, provide you his view on what effect your proposed power cost framework would have on PGE's cost of capital?

A No.

Q That concludes our questions. Thank you.

MS. ANDRUS: I have no redirect and we'd like to review the transcript for corrections. And we'd like a copy of it.

(Proceedings concluded at 2:10 p.m.)

had starting storage reservoirs nominally full, which again provided a good updated base for the analysis.

We re-ran the study in continuous mode with respect to both the U.S. and Canadian storage reservoirs to remove the distortion caused by the discontinuity in the non-refill years of the simulation, as discussed previously.

Finally, in consultation with the Northwest Power Pool staff, we adjusted the end-of-January target draft at the Canadian storage reservoirs to compensate for an obvious and explainable difference between actual and PNCA-simulated January reservoir operation.

Q. Please explain average hydro energy, as used in the RVM proceedings.

A. This method represents the average hydro energy for the next year, given the most recently available hydro-system non-power constraints, hydro resource ownership shares, etc. It is equivalent to running MONET with each of the 59 possible hydro conditions fom the period 1929-1987, all simulated to occur in the next year, averaging the hydro energy for each month, and making one MONET run with that average hydro year. However, an important point is that it simulates the next year only. It does not simulate any year beyond the RVM.

Q. Are there any other conclusions you would like to point out regarding average hydro?

A. Yes. It does not simulate hydro conditions outside of the 1929-1987 period or more extreme hydro conditions. It also does not simulate the next 59 years into the future, nor does it necessarily include information to generate hydro conditions beyond the next year. This is because:

(1) Hydro system non-power constraints (for example, fish flows) change over time into the future,
(2) Hydro resource shares change over time into the future (e.g., decrease of Mid-Columbia plant shares), and

(3) The distribution of potential hydro production outcomes may not be represented by the 59 years. For example, see PGE Exhibit 400 for a discussion of climatic cycles.

In the next section, we will discuss Expected Value Power Cost, which would vary market prices in response to changing hydro conditions and other uncertain variables. However, as we will see, this approach also has significant limitations, including those mentioned here.

Q. What do you conclude about "average" hydro output?

A. Average hydro output is only a snapshot at a particular point in time, given the constraints at a particular point in time. Over time, "average" hydro changes as these constraints change. In general, we would expect constraints to tighten as environmental measures tighten and demands on stream flows for alternative uses (e.g., irrigation, recreation) increase over time. Given this trend, all else equal, "average" hydro output would be expected to decline.

Q. Is there anything else that would cause "average" hydro to change over time?

A. Yes. Average hydro output is also a function of the hydro resources themselves. PGE's resources are not static. The contractual resources that PGE has at the Mid-Columbia projects will expire. PGE's owned hydro resources change over time due to natural degradation of plant performance, upgrades where possible, closures or decommissioning of facilities (e.g., Bull Run), etc. As a result of these factors, the "average" output of hydro facilities will also change over time. Finally, as discussed in the testimony of Dr. Phil Mote in PGE Exhibit 400, the impact of climatic cycles and other events calls into question the stability of an "average" defined by 59 (or 69) years of data.

Q. Why is the dynamic nature of both the operating constraints and the resources to which the constraints apply an important consideration?

A. PGE establishes an expectation of net variable power cost in RVM proceedings on the basis of average hydro. The actual hydro output that we experience in any given year can deviate substantially from that average level of output. Since the average hydro output changes, there is no reason to think that the benefit of good hydro years will necessarily offset the detriment of bad hydro years. In other words, there is no reason to believe that the use of average hydro results in inter-temporal matching of costs and benefits associated with deviations around those averages. Thus, the use of average hydro is not an appropriate tool to balance the costs, and benefits, associated with the variability of hydro output around some notion of average hydro. Rather, it is simply a methodology to forecast hydro based on typical conditions.

Q. Are there any other reasons that the costs and benefits of hydro deviations may not offset one another over time?

A. Yes. In addition to a changing resource base and changing operating constraints, the financial impact of hydro deviations tends to change over time. For example, prior to the changes of the 1990s discussed in PGE Exhibit 200, replacement power costs were effectively capped at cost-based rates based on a coal or nuclear unit. As a result, if we had a shortage of hydro in 1985, the price we would pay for replacement power was largely known based on the cost of output of the next marginal resource in the regional resource stack.

As described in PGE Exhibit 200, replacement power costs are largely dependent on the national gas market, which tends to be a significant driver of wholesale electric market prices. Increases in gas prices have led to higher market electric prices. In 1999, the average price of gas at the Sumas hub was about $2.00/MMbtu. Today, forward prices of gas at Sumas for 2005 are more than three times that level. Further, since hydro conditions tend to be regional in scope, PGE tends to experience poor hydro along with the entire Northwest. Short supplies of hydro in the region tend to drive up market prices for power, exacerbating the cost of replacement power for PGE. By contrast, when PGE has excess hydro power supplies, the region also tends to have excess hydro output, depressing market prices and the value of the excess hydro output. Thus, the value of excess hydro when output exceeds the average tends to fall short of the detriment of replacement power cost when output falls short of the average.

III. Expected Value Power Cost

A. Background

Q. How important is uncertainty in forecasting power cost?

A. Uncertainty is very important. In developing a forecast of power costs, the economics of a resource plan or other projects, a key issue that analysts deal with is uncertainty. In developing a power cost forecast, we develop estimates of many input assumptions such as power plant capacities and heat rates, availability parameters, fuel prices, market electric prices, purchases and sales, hydro generation, loads, and others. Most of these parameters and variables are uncertain to some degree. For some parameters, the uncertainty level is relatively low, such as thermal plant capacity, heat rate, variable O&M, fuel sulfur content, contractual purchases of fuel or electricity, and others. Some variables are more uncertain such as natural gas market prices, electric market prices, loads, hydro generation, and plant availability. Furthermore, these latter variables tend to be correlated to different degrees with one another, creating a complex web of potential interactions.

Each element of uncertainty tends to add to the overall risk or dispersion of potential power cost outcomes. For example, PGE is subject to uncertainty related to a number of variables including thermal/hydro plant performance, loads, market electric prices, market gas prices, and any correlation between those variables. However, some of those risks, to a degree, can be managed by PGE, such as prudent management of our plants with adequate investment and O&M spending to ensure the cost-effective level of plant availability. Uncertainty in electric and natural gas prices can be managed by entering electric and gas physical and financial contracts to hedge those risks.

However, one variable stands out prominently among the rest in terms of its ability to cause large variations in power cost that are largely beyond PGE's ability to control or manage, and that variable is hydro generation. First, PGE has absolutely no control over hydro conditions. Hydro conditions develop and evolve <u>after</u> the forecast is set. As we noted above, PGE hydro generation is essentially at a zero variable cost. When there is surplus or deficit hydro generation, it will result in large changes in power cost. Second, the level of regional hydro generation has a direct and substantial effect on the market price of electricity, and it can even affect the price of natural gas by changing the demand for gas at the gas-fired generating plants in the WECC. These effects on market prices compound the variability of power cost.

Q. What is Expected Value Power Cost?

A. Expected Value Power Cost is a method of forecasting power cost that simulates a spectrum of alternative states for relevant variables to develop a central power cost estimate. By contrast, the current methodology employed by MONET is "deterministic," taking into account only one estimate of the relevant variables.

B. Development of Expected Value Power Cost

Q. How is Expected Value Power Cost developed?

A. Theoretically, to rigorously forecast expected value power cost under uncertainty, we would stochastically vary all uncertain variables, with appropriate correlations or fundamental economic relationships. These variables include:

- The statistical distribution of future market electric prices, including the impact of non-fundamental factors such as scarcity premiums and the relative likelihood that such events would impact market electric prices.

- The statistical distribution of future market gas prices, including the impact of non-fundamental factors such as scarcity premiums and the relative likelihood that such events would impact market gas prices.
- The statistical distribution of future hydro generation.
- The statistical distribution of future PGE and regional loads.
- The correlation between market electric prices and hydro generation.
- The correlation between market electric prices and gas.
- The correlation between PGE/regional loads and market electric prices.
- The correlation between PGE/regional loads and market gas prices.

One technique would be to use random draws in a Monte Carlo approach. To do this adequately is a large task, and we do not currently have the modeling capability to do this.

Q. Couldn't you model just the important correlations or fundamental economic relationships?

A. Yes, we could but the estimate would be biased and unreliable. For example, if we chose to ignore PGE and regional load variability and focused on the remaining variables, we would be ignoring relevant information that could impact PGE's power costs under uncertainty. Variations in PGE and regional loads have the potential to impact the market price of power and the market price of gas, both of which would impact PGE's power cost. The failure to develop a complete picture of Expected Value Power Costs undermines the validity of the exercise.

Q. Is MONET capable of modeling Expected Value Power Cost?

A. Theoretically, yes. In particular, MONET could do this if it were a limited case of simply allowing for the variability of market electric price in response to varying hydro generation. Expected Value Power Cost could be modeled in MONET as the average power cost for the 59 hydro conditions, with the MONET model run in fundamental mode with market prices varying with hydro conditions. If done correctly, the Expected Value Power Cost forecast provides an equal dollar risk of over-collecting or under-collecting costs in rates for the next year as it relates to varying hydro conditions. However, as we have already pointed out, such as exercise would tend to be biased because it would ignore other relevant economic relationships that impact PGE's power costs under uncertainty. It would also ignore any extent to which the market might deviate from fundamentals.

Q. What would you expect the result of developing Expected Value Power Cost to be relative to Average Hydro Power Cost?

A. We do not know the result of performing a comprehensive Expected Value Power Cost calculation compared to that produced by MONET run in deterministic mode with Average Hydro Power Costs. Even for the more narrow case of allowing for varying hydro generation to impact market price there are two effects:

- First, an impact on our expected power cost related to varying hydro conditions.
- Second, an associated impact on thermal plant dispatch resulting from market price variability.

The two effects are in offsetting directions, with thermal plant optionality reducing power cost and hydro variability increasing power cost. We cannot indicate what the net impact would be for a forecast of power cost that includes both.

Q. Please describe the first effect of a narrow definition of Expected Value Power Cost: the impact of varying hydro conditions.

A. In the absence of thermal plant dispatch effects (discussed shortly), Expected Value Power Cost tends to be greater than Average Hydro Energy Power Cost. This is true because power cost increases greater than linearly as hydro generation decreases, reflecting the inverse relationship between hydro generation and market electric prices. Figures 1 and 2 show this relationship in concept.

Figure 1
Market Electric Price and Power Cost vs. Hydro
(Hypothetical for 1 hour, Illustrative – Flat Market Price)

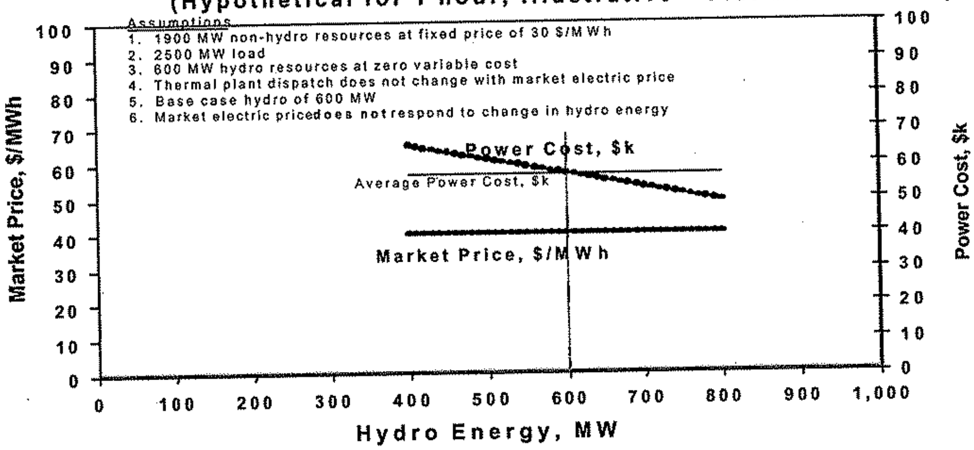
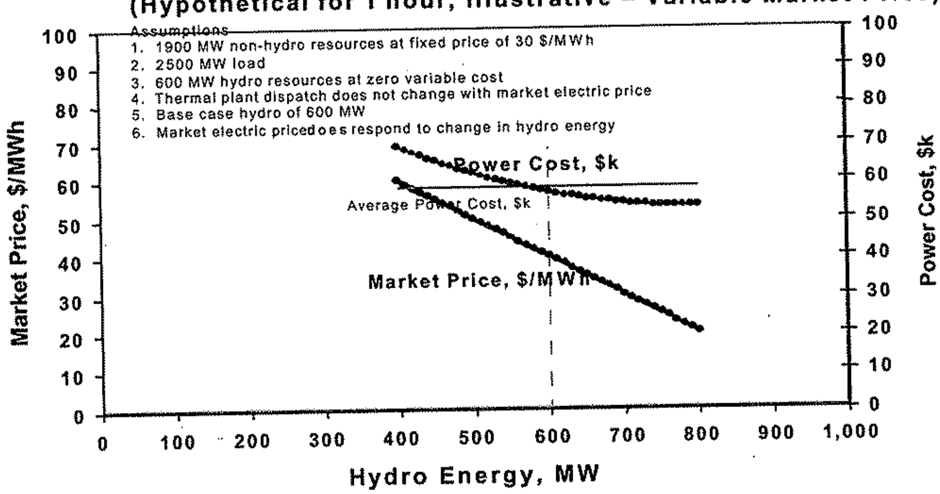


Figure 2
Market Electric Price and Power Cost vs. Hydro
(Hypothetical for 1 hour, Illustrative – Variable Market Price)



In Figure 1, the market price of power is assumed to be fixed and unresponsive to changes in hydro generation. As a result, Average Hydro Energy Power Cost and Expected Value Power Cost are identical. However, if market prices respond inversely to changing hydro conditions (i.e., prices are higher when hydro generation declines), then Expected Value Power Cost will always exceed Average Hydro Energy Power Cost as illustrated in Figure 2, in the absence of changes in thermal plant dispatch. In other words, setting rates on the basis of Average Hydro Energy Power Cost will always result in under-recovery of power cost in the absence of changes in thermal plant dispatch.

Q. Did you perform any studies to illustrate this impact?

A. Yes. PGE Exhibit 301 provides an analysis of PGE's potential losses from not using Expected Value Power Cost under alternative illustrative relationships between hydro conditions and electric prices in the absence of changes in thermal plant dispatch. In other words, PGE has a cost of service that is not recovered by not utilizing Expected Value Power Cost related to varying hydro conditions. Based on these assumed parameters, PGE's forecasted power cost would increase by somewhere between one and seven million dollars. However, these are <u>illustrative results</u> only. We can conclude that, in the absence of thermal plant dispatch, PGE suffers an expected loss each year by using Average Hydro Energy Power Cost rather than Expected Value Power Cost, but we can't say definitively how much. The amount could be higher than $7 million annually. One of the difficulties in developing Expected Value Power Cost is developing reasonable parameters for the relationship between hydro generation and market electric prices. The study in PGE Exhibit 301 illustrates just how much the end result can vary under different parameter assumptions.

Q. Please describe the second effect of a narrow definition of Expected Value Power Cost, the impact of thermal plant dispatch from varying market electric prices.

A. Thermal plants can be thought of as having optionality under changing or uncertain conditions. For example, all else equal, when electric prices increase, thermal plants can be dispatched more to displace expensive market electric purchases, reducing power cost below what they would otherwise be. Conversely, when electric prices decrease, thermal plants can be dispatched less to take advantage of cheaper market electric power to purchase instead. This thermal plant dispatch optionality tends to reduce power cost. The value of this optionality, or option value, is often resolved into two components, *intrinsic value* and *extrinsic value*. The intrinsic value is the dispatch value reflected in the current forward market conditions, which we use as the forecasted conditions in our power cost modeling. The intrinsic value could theoretically be "locked in" and hedged now using contract purchases of gas and sales of electricity in the forward market. However, rather than this "locking in" approach, we will focus on the plant dispatch value under the MONET base forecast conditions as representing the intrinsic option value.

For example, suppose we have a completely flexible 100 MW gas-fired plant that can be fully dispatched up and down from one hour to the next at a constant heat rate with no unit commitment requirements or start-up costs. For simplicity, further suppose that the plant has no variable O&M cost. Suppose that in a particular hour the electric trading curve (used as the baseline forecast) price is $50/MWh, and the variable fuel cost at the gas trading curve (used as the baseline forecast) is $45/MWh. The dispatch value of the plant for the hour is $500.

$$\text{Intrinsic Value} = \text{Base Forecast Dispatch Value} = (100\text{ MW})(\$50/\text{MWh}-\$45/\text{MWh})(1\text{ hr})$$
$$= \$500$$

Power cost is $500 less than what it would be if we didn't have this plant in our portfolio. This thermal plant intrinsic value is reflected in our current RVM modeling, in which we use a single MONET run with trading curves, average hydro energy, and central forecasts for other variables.

On the other hand, because we model only one baseline case, the *extrinsic* option value is not reflected in our current modeling. However, if we switch to Expected Value Power Cost modeling, we begin to reflect extrinsic option value. To illustrate, suppose we modify our example to include three equally likely electric prices for the example hour, the fuel price being the same in all cases. The possible electric prices are \$40, \$50 and \$60/MWh, with the baseline forecast still at \$50/MWh. In the \$40 /MWh case, the plant doesn't run and no dispatch value is generated. In the \$50/MWh case, the plant runs and generates \$500 of dispatch value per the original example. In the \$60/MWh case, the plant runs and generates \$1,500 of dispatch value.

Dispatch Value = (100 MW)(\$60/MWh-\$45/MWh)(1 hr)
= \$1,500

If these three equally likely cases were the only possible outcomes, the extrinsic option value would be the expected value of the dispatch value less the intrinsic option value,

Extrinsic Value = (Expected Value of Dispatch Value) – (Intrinsic Value)
= (0 + 500 + 1,500)/3 - 500
= 666.67 – 500
= \$166.67

We can think of the plant as having optionality value in terms of its ability to shut down in the \$40/MWh case, but this is relative to the plant running at a loss in that case by generating at \$45/MWh when we could purchase power at \$40/MWh. However, that value is relative, and the true option value of the plant is the value of having the plant vs. not having the plant. That value in the example is the expected value under the uncertainty of the three possible cases, or \$666.67. The intrinsic value is still \$500, and the extrinsic value is the remaining \$166.67. The sum of the intrinsic value and the extrinsic value is the total option value, which equals the total expected value of the variable economic value of the plant, which excludes its fixed costs.

Q. Why is this important?

A. The simple example illustrates the theory behind Expected Value Power Cost as it applies to thermal resources. However, just as PGE Exhibit 301 shows that the results of PGE's expected loss on hydro can vary greatly depending on the assumed relationship between hydro generation and market electric prices, so too can the calculated extrinsic value of our thermal resources change greatly when the assumed parameters change. Based on the example above, the calculated extrinsic value could change greatly with the incorporation of an assumed relationship between gas and electric prices or by changing the relative probability of events. Again, the examples above only illustrate the narrow definition of Expected Value Power Costs, ignoring other potentially relevant variables and relationships. The failure to take these into account introduces the potential for bias into the results.

Q. What does Expected Value Power Cost represent?

A. <u>Assuming</u> all relevant variables are defined accurately, it represents a "fair roll of the dice" with respect to expected power cost recovery for the <u>next</u> year. If you roll the dice many times (i.e., many simulations of <u>next</u> year), the deviations between the simulations and Expected Value Power Costs for <u>next</u> year will tend to even out. The method simulates individual or aggregated draws of possible hydro conditions from the period 1929-1987, simulated to occur in the next year. It simulates next year only and not years into the future.

Q. Do you have any other comments regarding Expected Value Power Cost?

A. Yes. Expected Value Power Cost does <u>not</u> represent a ratemaking response for treating the volatility of power costs around the baseline forecast. It does not simulate hydro conditions outside of the 1929-1987 period or other more extreme hydro conditions. It does not handle unanticipated events (e.g., the 2000-2001 California Power Crisis), and generally is very poor at reflecting non-fundamental factors such as market psychology. It also does not simulate the next 59 years into the future. This is because:

(1) Hydro system non-power constraints change over time into the future.

(2) Hydro resource shares change over time into the future.

(3) The distribution of potential hydro production outcomes may not be represented by the 59 years. For example, see PGE Exhibit 400 for a discussion of climatic cycles.

(4) The relevant parameters (e.g., hydro/market price relationship, gas/electric price relationship) are not static. As a result, even if the parameters are defined correctly for one year, they will tend to change over time. Thus, a deviation in power cost that is consistent with a distribution of potential outcomes in year 1 could not be expected to be offset with a deviation in power cost in year 2 (or some other future year) that is consistent with a different distribution of potential outcomes.

Q. Neither Expected Value Power Cost nor Average Hydro Power Cost represent a simulation of the next 59 years. Why is this important?

A. This means that neither approach can be expected to produce a result in which "good years" offset "bad years." In other words, there is no reason to expect an inter-temporal matching of the costs and benefits associated with PGE's hydro resources because rates were set on Average Hydro Power Cost or Expected Value Power Cost.

Q. What are the barriers to implementing an Expected Value Power Cost methodology in MONET?

A. Implementation of the Expected Value Power Cost method is much more analytically and computationally challenging than the Average Hydro Energy method. Constraints to implementing Expected Value Power Cost include the following:

a. Defining correlations between variables
b. Calibrating model results to actual results
c. Modeling complexities of the WECC
d. Modeling market responses outside of standard economic responses (e.g. 2000-01 California Power Crisis)
e. Long model run times
f. Reconciling fundamental simulations with the use of trading curves.

Q. What is the implication of these barriers to the development of Expected Value Power Cost?

A. While Expected Value Power Cost is based on a solid theoretical basis, it introduces significant challenges into the ratemaking process. The use of Expected Value Power Cost is less transparent and requires the derivation of complicated (and non-static) relationships that can have a significant impact on the end result.

Q. Even if Expected Value Power Cost could be confidently derived, does this mean that PGE doesn't need the Hydro Tariff that it seeks in this docket?

A. No. First, as we indicated before, neither the use of Expected Value Power Cost nor Average Hydro Energy Power Cost will ensure that the impact of "good" and "bad" years will simply offset one another. Second, as described in the study in Exhibit 301, the use of Expected Value Power Cost does nothing to address the risk of variability around hydro. At its best, the use of Expected Value Power Cost is no more than a better point estimate for *next year*, it is not a simulation of the next 59 years. Finally, PGE faces the potential for a

Gambler's Ruin problem, experiencing several consecutive poor years of hydro which, while they may be consistent with a particular probability distribution of expected outcomes, could nonetheless lead to financial catastrophe for PGE. As Keynes noted, "In the long run, we are all dead." Keynes may have been referring to a different phenomenon; however, neither PGE nor our customers should wait for 59 years to be made whole with respect to hydro resources.

Q. You have indicated that both the use of Average Hydro Power Cost and Expected Value Power Cost have shortcomings when used for rate making purposes. What do you recommend that the Commission use for capturing the costs and benefits of hydro resources?

A. We recommend the use of Average Hydro Power Cost in setting rates along with the Hydro Generation Adjustment (HGA) to treat variations in the forecast level of hydro generation. The use of Average Hydro Power Cost is consistent with the rate making criteria outlined in PGE Exhibit 100, in particular transparency. Given the small deadband in the HGA, PGE can accept the bias against investors resulting from not reflecting the effect of hydro variability on market eletric and fuel prices.

Expected Value Power Cost adds tremendous complexity to the rate setting process with no promise of a more accurate outcome. In addition, the use of Expected Value Power Cost does not obviate the need for a mechanism such as the HGA to handle variability of results around hydro generation. In general, we feel the best way to handle uncertainty associated with power costs is the development of after-the-fact tracking mechanisms rather than using questionable modeling techniques in an attempt to forecast that uncertainty.

Portland General Electric

Hourly Power Cost Simulation

July 10, 2006

PA

Portland General Electric

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Appendices

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1. INTRODUCTION

PA Consulting Group has been retained by Portland General Electric to define a "cost simulation model". The basic simulation model would simulate the net variable power cost over a period of time subject to certain assumptions about loads, market prices, hedges in place and hydro conditions. That model could then be run over a large sample of potential realizations of those assumptions in order to estimate the statistical properties of the distribution of net variable power costs.

In the course of PA's work on this assignment it became clear that an important factor limiting the precision of any probabilistic cost simulation is the availability of data describing the distributions and dependencies of its uncertain inputs. PA produced a report explaining the level of detail at which data might be desired, the difficulties in assembling such data, and stopgaps or proxies that might be used on an interim basis. The recommendation from that report was that PGE proceed with the definition of a flexible prototype simulation structure, which could be used to test different data relationships and resource modeling choices. PA has described this flexible structure as a "sandbox".

This document is the Final Report from PA's assignment. It is organized as follows:

- List of major assumptions that define the problem being modeled
- Significant sections of the Data Issues Report
- Overall structure of the prototype model
- Input data modeling in the prototype. This refers to the representation of variables such as load, gas price, power price and hydro conditions, and the relationships between them.
- Resource modeling in the prototype. A "resource" is any source or sink of the power distributed by PGE, or any hedge on PGE's net variable power cost.

2. *UNDERLYING ASSUMPTIONS*

2.1 NATURE OF THE SOLUTION SOUGHT

PGE was seeking a simulation model that would produce information about the shape of the distribution of net variable power costs. The "location" of that distribution is represented by the Resource Valuation Mechanism (RVM) forecast, that is, a base case Monet run.[1] Therefore the function of the probabilistic simulation is to perturb the Monet input parameters in a way that is consistent with historic distributions of those parameters, and report the shape of the ensuing distribution of net variable power costs (as well as any shifts in the mean).

From this assignment, PGE was seeking a description of a model that it could easily implement if need be. It might be desirable to incorporate the model into Monet but at the very least it should be compatible with Monet. PA interpreted this to mean a simple Excel-based model, which could use, when appropriate, the same logic as Monet (even reusing code from Monet or DLLs it calls).

2.2 14-MONTH TIME HORIZON

The question addressed by this simulation model is the extent by which Portland General's actual costs for a year can differ from the cost forecast used for setting the revenue requirement in the RVM. That revenue requirement is set in November and covers the following year. Therefore the model has a 14-month time horizon, from Nov. 1 through Dec. 31 of the following year (costs during the first two months are not accumulated).

2.3 NO UNCERTAINTY ABOUT RETIREMENTS OR NEW CAPACITY

Because the model horizon is only about a year and a quarter, we assume that PGE's resource base is known. It may change during that period – resources may be retired or added – but the schedule of retirements and additions during the model horizon is known with certainty. Therefore, there is no need for estimation of the parameters of new candidate resources or for capacity expansion decision-making. Furthermore, the technological parameters (heat rates, capacities, outage rates) of those resources are already known. "Disruptive technological change", for example, would not affect the intra-year cost uncertainty, but rather would move the entire distribution of costs including the RVM forecast.

2.4 SPOT MARKETS ARE FULLY LIQUID

The first consequence of this assumption is that each resource may be modeled as if it were dispatched based solely on the price, rather than to meet load. PGE's Monet model accounts for load-following, to the extent that it refers to shaping supply to loads that change within the hour but achieve an anticipated average value, by reserving Mid-C hydro capacity and

[1] The specific Monet run to which the prototype was constrained was based on the file M606PUC05-105-06.xls that was provided to us.

assuming the net energy impact is nil. If the anticipated average value is not achieved it represents a real-time load excursion described in the next paragraph.

The second consequence is that all real-time load excursions beyond those anticipated as "load following" – in other words, all differences between the real-time integrated load for an hour and the day-ahead forecast – can be covered in the spot market. It is not necessary to reserve hydro capability to cover those excursions, although available hydro capability could be used to respond to real-time price fluctuations. It is explicitly assumed that there will always be sufficient spot liquidity to meet all demands or sink excess supply at the spot price (even though that price may be very high).

2.5 DECISION VS. VALUATION TIMEFRAMES

Because the real-time spot market is assumed to be perfectly liquid, and because any net imbalances are settled in real time, we assume that all energy – generated or purchased by PGE, or delivered to loads – is valued at the real-time spot price. However, most resources need to be scheduled in advance. Therefore "advance" prices, e.g., day-ahead prices, have to be used for dispatch decision-making. In some cases, a basic schedule may have to be set based on the advance prices subject to a limited amount of flexibility to respond to real time spot prices.

3. DATA ISSUES

3.1 DATA BY COMPONENT

In this section we will review the different components we expect the simulation model to contain, and list the data required by each one. As noted above, we are assuming that PGE's power dispatch decomposes, so that energy resources are scheduled independently. The value of the energy from each resource is computed based on spot power prices; the net value of the resource is its energy value minus the generating cost (fuel and O&M). Similarly the cost to serve load is computed based on spot prices. The net variable power cost is the difference between the cost to serve load and the total net value of resources. Each different resource type is a component of the model.

3.1.1 Load

The load component determines the cost to serve load. It requires two different variables, namely hourly load and the real-time hourly spot price, both of which are uncertain. Forecasting hourly load may require a "hidden variable" such as temperature. Given that the simulation model is completely decomposed and that we assume the real-time market is completely liquid no "load forecast" variables are necessary except for determining the reserve requirement (see the description of the hydro component below).

3.1.2 Gas-fired plants

The gas-fired power plant component includes PGE's gas-fired power plants – Coyote, Beaver and Port Westward (when operational). These plants are scheduled based on the gas price and an advanced power price, and "paid" based on spot power prices. In addition, the Beaver plant may have some ability to modify its schedule to respond to real-time or near-real-time price movements. We understand that there is no regime of tradable NO_x permits in the Northwest (when one is implemented the model would have to be modified to account for NO_x costs, which are likely to covary with load and gas prices).

A. DATA REQUIREMENTS – CERTAIN

The gas-fired plant component requires the following data for each plant:

- Definition of operating states. These can be used to represent dynamic constraints on startup and shutdown, ramping, or a non-constant heat rate.
- State transition matrix. Note that the state detail may be ignored or approximated for this simulation model, relative to the detail in Monet.
- Capacities
- Measure of flexibility for Beaver, which is the one plant whose dispatch apparently can respond in near-real-time
- Heat rates
- Outage rates (may vary by operating state)

- O&M cost
- Gas tariffs
- Maintenance schedules

B. DATA REQUIREMENTS – UNCERTAIN

The gas-fired plant component requires the following uncertainty data:

- Gas prices at Sumas and Stanfield. AECO prices, Rockies (e.g., Opal) prices or even Henry Hub prices could be used as "hidden" variables
- Day-ahead hourly Mid-C power prices, for use in dispatching
- Mid-C power prices with a timing appropriate to Beaver's scheduling flexibility (probably 4 hours ahead of real time)
- Real-time Mid-C power prices

3.1.3 Coal-fired plants

The coal-fired power plant component includes PGE's coal-fired power plants – Boardman and its share of Colstrip. These plants are scheduled based on the coal price and an advanced power price, and "paid" based on spot power prices. Although coal-fired plants incur costs associated with sulfur emissions we understand that there is no regime of tradable NO_x permits in the Northwest (when one is implemented the model would have to be modified to account for NO_x costs, which are likely to covary with load and gas prices).

A. DATA REQUIREMENTS – CERTAIN

The coal-fired plant component requires the following data for each plant:

- Definition of operating states. These can be used to represent dynamic constraints on startup and shutdown, ramping, or a non-constant heat rate. Monet actually does not define operating states for these plants, which assumes that they will run pretty much baseloaded and satisfy all operating constraints.
- State transition matrix.
- Capacities
- Heat rates
- Outage rates (may vary by operating state), which includes transmission outages
- O&M cost
- Coal prices – Colstrip is a mine-mouth plant so its coal cost is likely to be known; Boardman currently has a long-term coal contract and it is reasonable to expect that even after that contract runs out it will be supplied on contracts of at least annual duration (so the coal price is not uncertain relative to this model's 14-month horizon)
- SO_2 emissions rates

- SO_2 allowance prices – we assume that SO_2 allowance prices are certain because the sulfur market is national and associated with baseload generation
- Maintenance schedules
- Transmission costs

B. DATA REQUIREMENTS – UNCERTAIN

The coal-fired plant component requires the following uncertainty data:

- Day-ahead hourly Mid-C power prices, for use in dispatching
- Real-time Mid-C power prices

3.1.4 Hydro plants

The hydro power plant component includes PGE's hydro plants and Mid-C contract. These plants are scheduled with at most intra-month flexibility, that is, the total energy for each month is known at the scheduling time horizon (although it is uncertain at the 14-month horizon).

A. DATA REQUIREMENTS – CERTAIN

The hydro plant component requires the following data for each plant:

- Capacity (for some plants this will be uncertain, that is, dependent on hydro conditions)
- Overmonth storage, that is, the amount of that may be carried from month to month
- Amount of capacity that must be withheld for load-following or reserves (may be expressed relative to load or total fossil generation)
- Amount of capacity that must be scheduled to allow for downward load-following or downward regulation (again, may be expressed relative to load)
- Outage rates (may be 0)
- O&M cost
- Maintenance schedules
- Measure of rescheduling flexibility, which represents the ability to change the schedule to respond to day-ahead or real-time prices (and the way in which changes in energy usage are redistributed within the rest of the month)

B. DATA REQUIREMENTS – UNCERTAIN

The hydro plant component requires the following uncertainty data:

- Monthly energy available by plant.
- Monthly capacity by plant, for those plants whose capacity varies with hydro conditions

- Monthly run-of-river (minimum dispatch level) energy by plant
- Monthly forecasted hourly Mid-C power prices, for use in dispatching
- Day-ahead Mid-C power prices, for rescheduling
- Mid-C power prices with a timing appropriate to Beaver's scheduling flexibility (probably 4 hours ahead of real time), for rescheduling
- Real-time Mid-C power prices

The final model design may not include all the layers of rescheduling described above.

Note that "hydro condition" or "hydro availability" may be a hidden variable that influences energy, capacity and must-run energy. The Monet model that PGE currently uses for revenue requirement forecasting assumes that all hydro units other than Mid-C are inflexible – the hourly dispatch for every hour is fixed relative to the annual average. The Mid-C contracts are assumed to be flexible within the month but not month-to-month. Essentially, over-month storage is disregarded because energy has already been allocated to each month by the NWPP hydro model.

The NWPP model may use rule curves but does not explicitly account for conditional hydro probabilities. An example of a conditional hydro probability would be the probability that inflows in February would be consistent with historical hydro year 1955 given that January was consistent with historical hydro year 1937. Assessing non-uniform conditional probabilities is a difficult task and would be facilitated by a historical forecast database. We believe that the NWPP model deterministically applies the conditions of a specific historical hydro year in each month but have not yet seen model documentation.

3.1.5 Hedges and term power purchases and sales

This component describes PGE's hedges and term power contracts, in place as of November for the following year and modified as improved load and hydro forecasts become available. Forward power contracts don't really affect the distribution of net variable power costs except for moving its mean, but option contracts will affect it. We have not examined PGE's hedge book but we have been led to believe that it is dominantly forwards, fixed-for-float swaps and "vanilla" options priced either at Mid-C or COB.

A. DATA REQUIREMENTS – CERTAIN

The term transaction component requires the following data:

- List of hedges and transactions
- Transaction volumes by month
- Fixed prices for transactions, by month
- Identification of appropriate price indexes for transactions, by month

B. DATA REQUIREMENTS – UNCERTAIN

The hydro plant component requires the following uncertainty data:

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- Monthly peak and offpeak average power prices, at Mid-C and COB
- Daily peak and offpeak power prices, at Mid-C and COB

3.1.6 Spot price model

The spot price is not a model component in the same sense as the others. We have mentioned it here merely in order to be able to list some additional "hidden variables" that may be used in forecasting the spot price:

- Total Northwest hydro availability (as opposed to PGE hydro availability)
- Total Northwest regional load
- California load-resource balance
- California intertie capacity

3.2 SUMMARY OF DATA REQUIREMENTS

3.2.1 Certain data (Technological coefficients)

The following table lists the "certain data" identified above. We also label these "technological coefficients" since for the most part they are measurable properties of the technologies implemented in PGE's resource portfolio. For some of these we have initial or stopgap data sources (to be used for the prototype model), and the second column of the table identifies them. Blanks in the second column indicate that a source of initial data has not yet been identified.

Table 1. "Certain" data and preliminary sources

Data requirement	Source
Definition of operating states, Beaver/Coyote	Current Monet spreadsheet
Definition of operating states, Port Westward	
Definition of operating states, coal plants	
State transition matrix, Beaver/Coyote	Current Monet spreadsheet
State transition matrix, Port Westward	
State transition matrix, coal plants	
Capacities, existing fossil-fired and hydro plants	Current Monet spreadsheet
Capacity, Port Westward	
Measure of flexibility for Beaver	Current Monet spreadsheet

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Table 1. "Certain" data and preliminary sources

Data requirement	Source
Heat rates, existing fossil-fired plants	Current Monet spreadsheet
Heat rate, Port Westward	
Outage rates, existing fossil-fired and hydro plants	Current Monet spreadsheet
Outage rate, Port Westward	
O&M cost, existing fossil-fired and hydro plants	Current Monet spreadsheet
O&M cost, Port Westward	
Maintenance schedules, existing fossil-fired and hydro plants	Current Monet spreadsheet
Maintenance schedule, Port Westward	
Gas tariffs	
Coal prices	Current Monet spreadsheet
Colstrip transmission cost	
Overmonth storage for hydro plants	
Amount of hydro capacity that must be withheld for load-following or reserves	
Amount of hydro capacity that must be scheduled to allow for downward load-following or downward regulation	
Measure of rescheduling flexibility for hydro plants	
List of hedges and transactions	
Transaction volumes by month	
Fixed prices for transactions, by month	
Identification of appropriate price indexes for transactions, by month	

3.2.2 Description of uncertainty data

A complete description of any individual data series would cover five topics:

- Name or general description of the attribute of interest
- Numerical information (data element) to be used to represent the attribute of interest
- Substitute or proxy data element to be used if needed

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3. Data issues

- Historical values available for use in modeling the distribution of this data element and its relationship to others. Note that the data element described by the historical values may not be the same at the one to be forecasted

- Data that have been identified or located representing either the historical values or a proxy

The following table describes both the "uncertainty" data used by the model, as well as other "hidden" variables that might prove useful in modeling their distributions.

This table does not describe the other data with which each data element may covary; there were just too many possibilities, given all the different similar variables (such as power prices). Following the table we will list some generic covariances (generic because we refer to "power prices" rather than a specific power price data element) that may exist. Time will not permit all potential covariances to be tested.

Covariance does not imply causation; two correlated variables can have a common "causative" variable, but causation is not really a statistical concept. For example suppose that there is a plausible reason to assume that the value of variable *y* is determined by variable *x*, and in fact the "true" dependence relationship is $y = Ax + b + \varepsilon$ where ε is a normally distributed error. This can equivalently be written $x = A^{-1}y - A^{-1}b + \varepsilon'$ ($\varepsilon' = -\varepsilon$ is a normally distributed error) even though there is no "plausible" model under which *y* "causes" *x*.

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Table 2. "Uncertainty" data, covariances and related historical data

Attribute	Numerical values	Proxy	Related Historical data	Identified data
"Uncertainty" data				
Day-ahead power price at Mid-C	Hourly values in $/MWh	Day-ahead price at COB	Daily on and offpeak prices, hourly "scalers" based on ratio of Dow-Jones hourly indices	Dow-Jones daily (day-ahead) prices 1998-2004, hourly prices 2003-2004
Day-ahead power price at COB	Hourly values in $/MWh	Day-ahead price at Mid-C	Daily on and offpeak prices, hourly "scalers" based on ratio of Dow-Jones hourly indices	Dow-Jones daily (day-ahead) prices 1997-2004, hourly prices 2003-2004
Daily peak and offpeak subperiod prices at Mid-C	Average (index) values in $/MWh	Daily subperiod price at COB	Daily on and offpeak prices	Dow-Jones daily (day-ahead) prices 1998-2004
Daily peak and offpeak subperiod prices at COB	Average (index) values in $/MWh	Daily subperiod price at Mid-C	Daily on and offpeak prices	Dow-Jones daily (day-ahead) prices 1997-2004
Monthly peak and offpeak subperiod prices at Mid-C	Average (index) values in $/MWh	Monthly subperiod price at COB, daily subperiod price at Mid-C	Monthly price indices at close of trading of forward contract	
Monthly peak and offpeak subperiod prices at COB	Average (index) values in $/MWh	Monthly subperiod price at Mid-C, daily subperiod price at COB	Monthly price indices at close of trading of forward contract	
Short-term power price at Mid-C	Hourly prices in $/MWh projected four hours ahead	Real-time price at Mid-C		
Real-time power price at Mid-C	Hourly values in $/MWh		Actual historical hourly prices preferably from PGE trading floor	Dow Jones hourly prices 2003-2004

Table 2. "Uncertainty" data, covariances and related historical data

Attribute	Numerical values	Proxy	Related Historical data	Identified data
Monthly projected Mid-C prices, for hydro dispatch	Forecast of hourly prices for the entire month	Day-ahead prices at Mid-C		
Sumas gas price	Daily values	Stanfield gas price	Daily historical prices	Stanfield gas price 1994-2005 (PA data)
Stanfield gas price	Daily values		Daily historical prices	Stanfield gas price 1994-2005 (PA data)
Hydro energy	Available hydro energy by plant		Not necessarily needed as BPA forecasts energy	BPA white book
Hydro capacity	Monthly capacity by plant		Not necessarily needed as BPA forecasts energy	BPA white book
Run-of-river hydro	Minimum hourly hydro dispatch, by plant			
PGE cost-of-service load	Hourly load in MW		Historical hourly loads	Hourly PGE total load 2000-2004 and NCOS load for 2004; historical load from FERC form 714, 1993-2004

Hidden data

AECO gas price	Daily values		Daily historical prices	
Rockies gas price	Daily values		Daily historical prices	
Henry Hub gas price	Daily values		Daily historical prices	
Hydro condition (PGE)	Monthly energy		Historical hourly or daily	PGE hourly plant

Table 2. "Uncertainty" data, covariances and related historical data

Attribute	Numerical values	Proxy	Related Historical data	Identified data
	available		*energy dispatch* by plant	dispatch 1993-2005.
Hydro condition (NW)	Monthly energy available	Hydro condition (PGE)	Historical hourly or daily *energy dispatch* by plant	Federal system daily plant dispatch 1994-2002. Regional total monthly hydro energy 1997-July 2005 from NWPP.
Northwest regional load	Total hourly load in MWh	PGE control area load	Historical hourly load	Historical hourly load by control area from FERC form 714, 1993-2004
California load-resource balance				
California intertie capacity				Hourly intertie capacity data from 1998
Temperature	Daily max/min temperatures		Historical max/min temperature at a particular weather station, e.g., PDX.	

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A. POTENTIAL RELATIONSHIPS (COVARIANCES) AMONG UNCERTAIN VARIABLES

- *Power prices* may be related to (depend on) gas prices, regional load, hydro conditions, other power price variables, California load-resource balance, intertie capacity.
- *Gas prices* may be related to (depend on) California load-resource balance, regional loads, or other gas price variables.
- *PGE load* may be related to (depend on) regional load, temperature.
- *Temperature* may be related to (depend on) hydro conditions.
- Historical hydro dispatch (historical data used to estimate hydro conditions) may be related to (depend on) load.

3.3 ESTIMATION ISSUES FOR UNCERTAINTY DATA

As noted above, the goal of the project for which PA was retained is to estimate the statistical properties of the distribution of net variable power costs. This distribution is estimated by simulating costs over a distribution of the values for "uncertainty data". It is therefore important to estimate the distribution of those data. Furthermore the distribution of uncertainty data may be joint and nonseparable, in other words, the different uncertain variables may be mutually dependent. In this section we will address several of the key issues around that estimation. Most of the general issues of modeling dependencies are in section 3.3.6 while the general issues of single-variable modeling are in 3.3.7.

3.3.1 Descriptive vs. prescriptive modeling

The most important issue in estimating the distribution of uncertainty data is to understand the precision with which that distribution must be estimated. That depends on the use to which the end product – the estimated distribution of costs – is to be put.

The cost simulation model at issue here may be used for ratemaking. If the distributional outputs are to be used to set rates based on some kind of "risk-adjusted cost" it would be appropriate to invest considerable effort into the estimation of the underlying variables. We can call this a *prescriptive* analysis, where the model is used to determine a "once and for all" value. On the other hand, if there is an opportunity to "true up" the revenue requirement and the model is used to understand the likely size of the true up, the estimate can be less precise. We can call this, by contrast, a *descriptive* analysis. We will also use the term *descriptive* for a model used to determine a value subject to correction or true up, because it does not prescribe the value once and for all. It is important to clarify which kind of analysis is desired for this project.

As an analogy, consider the use of the Black-Scholes formula for option pricing. The Black-Scholes formula yields the price of a stock option based on two parameters, the risk-free interest rate and the "volatility" of the stock's price. There is an underlying assumption that the stock's price evolves under geometric Brownian motion. If the evolution assumption or the volatility parameter is wrong, the Black-Scholes formula will give the wrong value – and usually neither assumption is wholly correct.

Yet the Black-Scholes formula is used every day to value billions of dollars in options. The key is that the valuation occurs every day. Every day these options are revalued and the user, observing the market's reaction to the previous day's trading, is able to retune the parameters. Furthermore, because portfolios are adjusted every day the exposure to pricing errors is controllable (one can exit a position taken in error). If the formula were used to set the price for illiquid long-term options, with no opportunity to recover from error, it would be appropriate to invest considerably more time and effort into improving the modeling of the underlying random variables.

3.3.2 Estimating the impact of specification error

We believe that an important use for the cost simulation will be to determine the importance of precision in various inputs, and therefore the effort that ought to be invested in precisely estimating different relationships. In this report, we describe a number of questions about data relationships. Resolving all of them, and obtaining correct specifications for the joint distribution of the uncertainty variables, may be prohibitive. It is therefore important to determine the value of information: for each choice of models, how important is the difference?

A prototype cost simulation model can provide a tool for answering that question. A simulation model has three components: a deterministic simulation of dispatch and transactions; sampling from a distribution of input data; and a component that supervises the operation and reports results. Dependence and distribution issues impact the second of those components. Even if the deterministic simulation is just a prototype – not a complete or accurate representation of PGE's operations – it should still provide good *relative* information, as to which errors in input specification would have the greatest impact on results.

Again, the common use of the Black-Scholes model provides an analogy. That model is descriptive rather than prescriptive, in two ways. First, the model is used in an ongoing decision process, rather than to prescribe values "once and for all". Second the model is commonly used as a consistency check between "implied volatilities" of different options. In this usage the model provides not just a numerical result, but more important, a validation of its inputs.

3.3.3 Data availability

Our ability to estimate distributions is limited by the data available. Data unavailability could also affect the model design.

When data are not available we seek proxies that can be used as close substitutes. For example, as a proxy for "hourly forward prices" one often uses daily or monthly forwards to scale observations of hourly spot prices. The choice of a proxy is usually based on theoretical considerations. The underlying assumption is that the proxy is a good statistical predictor of the unavailable variable. The sensitivity of the model results to bias in the proxy should be tested using a descriptive approach.

There are several reasons why consistent historical datasets may not be available:

- Historical data may not exist because a particular data item has no historical analogue – for example, non-Cost of Service load.
- Trading or dispatch decisions may be based on data that is not archived. While actual (metered) load is surely archived, daily forecasts of future loads may not be.
- While historical values for some data may be archived, e.g., historical forward curves, the form in which the data is saved may make it costly to retrieve or organize for forecasting (e.g., daily reports that are not written to a standardized format).
- Data may be commercially sensitive, or its use might compromise commercially sensitive information. Current forward curves are generally considered sensitive. Historical forward curves may not be as obviously sensitive, but the combination of the historical curves and historical trading data might reveal an organization's trading strategies. Similarly, one might be able to infer position or trading limits from historical transaction data.

3.3.4 Impact of operation on recorded data

Distributions of random variables ought to be forecast based on observations untainted by human activity that could serve to mask or mitigate the variability in the underlying variable. This is particularly a problem when modeling power prices and hydro availability. In particular, the input variables to the cost simulation (the "uncertainty data") describe the flexibility or range of generation available from hydro under dispatch control but the historical data for a given year describe an actual realization of hydro generation.

- Power prices can depend on other exogenous variables, such as gas prices. However, they can also be affected by actions taken as a response to observed power prices, such as demand response or changes to the dispatch. By "dispatch" in this context we should understand only the dispatch of PGE units and contracts, which the simulation model represents as a function of prices; the dispatch of non-PGE units is an underlying uncertainty. PGE generation could be used as an explanatory variable in a statistical model of power prices, but the model estimation would need to account for the mutual dependence by using, for example, a multi-stage estimation.
- The situation with hydro condition estimation is even more complex. The data that are generally available describing historical hydro conditions are historical hydro *generation* values, which combine the effects of the hydrological state and dispatch decisions. If one is modeling the dependence of price on hydro one has to account for the fact that hydro generation is partly dependent on price. However, the form of that dependence in the past may not be the same in the future. The physical layout of the hydro system (impairments) changes slowly over time; the rule curves and environmental restrictions change more frequently. Historical hydro variables don't necessarily jibe with the values available as input to a cost simulation model. A separate model that derives monthly hydro capacity and available energy from hydrologic data such as precipitation represents the complexity of the Northwest hydro system.

3.3.5 Relationship between similar variables

Some generic data items, such as "power prices", are represented by multiple similar but non-identical specific variables. These can represent prices with different degrees of granularity (e.g., hourly, subperiod (peak/offpeak), daily or monthly), forward tenor (difference between the time or date at with the price is observed and the time of spot delivery) or delivery location. The various prices are all different and the various aspects of PGE decision-making rely on different prices. In fact, the differences between some of these prices are important to cost components such as the profit or loss from daily redispatch (trading). The relationships between such similar variables are often quite hard to model; for one thing, the differences between the "true" values of the respective variable can be of the same order of magnitude as the precision with which they are reported, or the bid-ask spreads.

In general theorists have paid the greatest attention to the modeling of forward tenor because it can be analogized to interest rate modeling, which is well studied. For example, the Clewlow-Strickland forward curve evolution model assumes that forward prices of different tenors are correlated but changes to long-dated prices are much smaller (attenuated) than changes to short-dated prices. Fitting such a model can be difficult. During periods of extreme spot-price volatility one may question whether a forward-curve model still holds – if the volatility is clearly due to short-term effects the attenuation should be greater. It is particularly difficult to answer this in the case of the 2000-2001 Western price shocks because liquidity in the forward markets basically dried up and publicly available historical long-dated prices are scarce or nonexistent.

The relationship between prices at geographically separate locations may require a regime-switching model. When transmission capacity is available the price difference is often a constant related to transmission costs (sign depends on the direction of flow) but when transmission capacity is all being used the prices are really uncoupled. Historical data about flows and capacities on interfaces is often hard to get. Analysts often use a single averaged "locational basis".

The most complex relationship, though, may be between prices of different granularities. For example, there is generally no "hourly forward price" or hourly forecast price. It is customary to create a profile of "scalers" that represent the ratio between an hour's actual load and that day's average load, and average the profiles over a period of time. This leads to a number of other questions, often ignored: what is an appropriate measure of the "standard deviation" of a scaler profile? Do forward prices scale the same as spot prices? Does the actual variation in profiles over time really represent variability in some hours' prices while others stay relatively constant (in which case the whole concept of a "scaler" profile would have to be rethought)? The final question goes to the issue of the appropriate definition of averaging periods; commercially-defined peak and offpeak periods are convenient for contract standardization but not necessarily for hourly price forecasting.

Fortunately, this complex relationship does not need to be modeled precisely. For, what is important in modeling PGE dispatch is not applying a "good" hourly detail to forward indexes; rather it is applying an hourly detail that is faithful to PGE's operational practice. In this case, statistical modeling is not as important as continued dialog with PGE staff to ensure that their forecasting methods – right or wrong – are replicated in the model.

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3.3.6 Relationships between dissimilar variables

In section 3.2.2a above, we provided a list of possible covariances or relationships among variables. To date, PA has focused its attention on possible relationships between power prices and gas prices, regional loads and hydro generation. We did not yet have good data representing such variables as PGE load, California load-resource balance, or intertie capacity. This analysis has involved most of the important issues in modeling relationships among variables:

- Form of the relationship. PA has modeled linear relationships between the input variables, between some of the variables and logarithms of the others, and where some of the variables are replaced by differences. We have not yet tried to neither model more complex transformations such as a logistic, nor have we modeled any form of regime switching. The simple linear model is appropriate for determining the existence and sense of a relationship, and can capture much of the variability. We have usually found log-linear models useful for both "descriptive" and "prescriptive" analysis but we recommend a separate computational test of the potential impact of specification errors. Furthermore, an R-squared value may not be a good measure of the applicability of the data model, as noted below.

- Comparability of variables. Available historical data series may not be appropriately comparable. For example we believe there are good fundamental reasons that power prices should be related to "net thermal load", that is, load minus hydro generation, and the coefficient of interest should be the common absolute value of the respective coefficients. For that relationship to hold, the net thermal load should be the load in a region without many transmission constraints and with substantial internal liquidity, minus the total hydro available in the same region. For load, we had the total load from FERC forms 714 of control areas identifies as being in the Northwest; for hydro generation we had the total generation for large Federal hydro plants, normalized to NWPP monthly hydro energy. Neither of those really corresponds to the region that determines Mid-C prices (the locational price we modeled). Although their coefficients were not of about the same absolute value the difference could be attributable only to their incomparability.

- Statistical independence. Dissimilar variables may not be statistically independent. One example, described earlier, is the relationship between price and hydro generation, since hydro generation responds to price expectations. Relationships that involve such mutual dependence are often estimated using multistage regression. However, in the extreme it may be necessary to employ a structural model of the relationship. In the case of hydro conditions and prices, PGE already uses a regional model to determine monthly hydro availability. A similar approach could be used to determine base case prices in each hydro condition, with the dependence on variables such as gas prices assessed separately. This in turn depends on the assumption that gas prices and hydro conditions affect power prices separable (otherwise the regional price model must be run for combinations of power prices and hydro conditions which is probably prohibitive in time and effort).

- Measure of goodness of fit. We typically assess the relationships between variables using some form of linear least squares. The common measure of goodness of fit is R-squared. While choosing the model with the highest R-squared, or even using any model with "sufficiently high" R-squared, may be reasonable for a cost simulation to be used in a descriptive mode, it does not assure the precision one would want in a prescriptive model. In that case goodness of fit should be measured by the absolute size of the residuals rather than relative to the total variation in the dependent variable, and the residuals themselves should preferably come from holdout samples.

- Stability of the relationship. Any algorithmic approach based on historical observations assumes that data relationships are stable; it is hard to imagine an objective approach based on anything else. (Delphi approaches are not sufficiently quantitative, especially for prescriptive modeling.) Although markets do change, the stability assumption is a reasonable one. Major market transformations will play out over periods of several years; the horizon of this model is only fourteen months, so data relationships derived with an emphasis on the last two years' worth of data should not be too far off the mark. Furthermore, it should be possible to provide manual override, where PGE or the OPUC staff can specify relationships to be imposed on the uncertainty data; however, when input data relationships are specified ad hoc the results should not be used prescriptively.

3.3.7 Modeling distributions of variables and errors

The uncertainty data we have described all involve independent uncertainties. In other words, while one variable may be related to several others it is not completely determined by them. Even though an uncertain variable may covary with many others, it involves an additional underlying uncertainty or error whose distribution must be simulated to provide inputs to the cost model. An independent variable, unrelated to any others, must also have its distribution assessed. The following issues are associated with distribution assessment:

- Relationship between historical data and variables to be forecast or estimated. Data about variables not particular to PGE will probably come from public sources. Even for variables directly related to PGE's dispatch we may have to fall back on public sources out of confidentiality concerns. Public data are often subject to various forms of processing that distort their relation to the variable being described, or to the variable whose future distribution they are used to estimate. An extreme example is the "system lambda" values filed with FERC, which often do not represent system marginal cost but rather a particular rule-based computation. Load data may represent control area load rather than retail deliveries; PGE meter data we have seen so far only separate out NCOS load for 2004.

- Choice of distribution. It is convenient to sample from an analytically defined distribution function, such as a normal, lognormal, exponential or Weibull distribution, rather than to rely on historical data. Extreme values are rare in historical data, but a large sample ought to include a number of extremes. Analytic distributions are used to extrapolate as well as fill in the historical record. However, it is often very difficult to distinguish between various choices of distribution without a theoretical model of the error process to guide the decision. With no other information the most reasonable way to choose the error distribution would be to rely on the Central Limit Theorem, assuming a large number of independent sources of error. If their effects add, the error distribution should be assumed normal; if their effects are multiplicative the error distribution should be assumed lognormal.

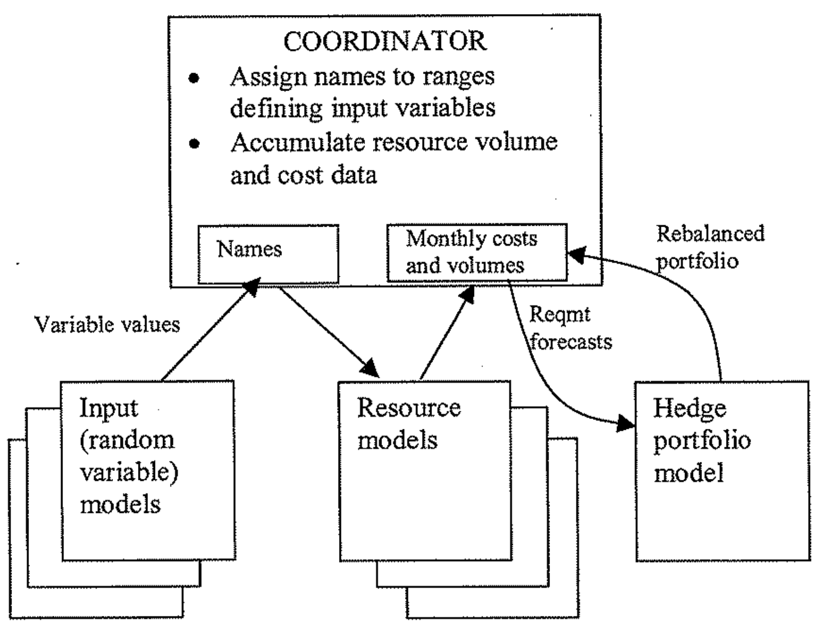
- Closed-from distributions vs. sampling of historical residuals. If there is no reasonable basis to choose an error distribution or if the distribution of historical residual shows clear non-normal behavior (e.g., multiple modes) one often has to fall back on using a discrete distribution based on historical residuals. This approach is more reasonable when there are a large number of historical residuals from which to choose – more than the number of samples to be taken – but it may be the only option when there is no obvious model for the data, even if the historical sample is small. This is the case in modeling hydro conditions. Hydrological conditions are represented by a large set of variables, reduced by a dispatch or regulation model to a set of energy and capacity values. The analytic structure of the energy and capacity data is too complex to model. Therefore one usually samples from a dataset associated with simultaneous historical observations of the hydrological variables, each historical year representing a distinct observation or item in the distribution.

4. MODEL STRUCTURE

We concluded that a cost simulation model had to be flexible and easily modified to test different ways of representing both the interdependencies of input variables and those resources for which unique "best models" cannot be defined – such as the forward hedge portfolio. We referred to this as a "sandbox" model because it provided a simple architecture for testing different approaches to individual resources.

The overall structure of the cost simulation is a Monte Carlo model. Different components of the simulation – different input models and resource models – are contained in separate workbooks (files), to make it easier to test different versions or configurations of the components and "mix and match". The names of the workbooks to be used for a particular run are specified in the Coordinator workbook. We settled on @Risk, a product of Palisade Corporation, as a platform for prototyping the cost simulation because it is Excel-compatible, can run models spread over several workbooks, is easily manipulated, and includes a good functionality for defining and extracting inputs and outputs.[2] @Risk manages the Monte Carlo simulation process.

The overall architecture of the cost simulation is illustrated below:



[2] We did come across one sporadic problem with @Risk. Some resource models, such as Beaver and Mid-C (which used DLLs), had to be calculated with VBA routines rather than just Excel workbook functions. This had to occur after the @Risk "recalculation", in which all the random variables are simulation. But then to get a correct calculation of the summary outputs, which used spreadsheet functions, we had to recalculate certain sheets programmatically (from the VBA code). @Risk would sporadically hang on the recalculation reporting an unknown error during the calculation.

4. Model structure

The building blocks of the cost simulation are input models, resource models (of which the hedge portfolio model is a special case) and a Coordinator.

The *input variable models* simulate the various random drivers for each iteration of the Monte Carlo simulation. The input variable models are based on Excel worksheet functions, and possibly VBA functions, but not VBA subroutines, in order to ensure that they are computed as part of the basic @Risk "recalculation" step prior to any programmatic resource models. Each resource model has as its output one or more arrays of random variables such as monthly hydro availability, daily gas price or hourly load. The input variable model "exposes" those arrays to the Coordinator by listing where each array is in the workbook and giving it a name. The Coordinator will assign a workbook a name to that array so that it can be referenced by other input models and the resource model – it looks like a named range in the Coordinator workbook.

The resource models simulate the operation of various resources (load, generators, physical power contracts and hedges). The resource models can obtain the values of input variables from the ranges defined by the names in the Coordinator. Each resource model can have up to four outputs: hourly MWh volume (produced or, in the case of load, consumed); non-power cost to produce those MWh; value of production at spot prices (or cost of load at spot power prices); and net profit. Each resource model includes a reserved range that tells the Coordinator where to find its output.

The resource models can also include VBA routines to be run prior to the simulation (to set up parameters), after the @Risk recalculation (in order to run VBA routines or DLLs such as for dynamic programming models of Beaver or the Mid-C contracts), or after the main group of resource models. The last option is for the use of the forward portfolio model: the forward portfolio is rebalanced over time as information emerges about the net position to be realized, but that requires the net short position (load minus physical resources) already to have been computed.

The Coordinator has three main functions. First, it assigns names to all the outputs of the input variable models, as if those models were storing their outputs in an area identified with the Coordinator. Second, it defines macros that call the VBA routines defined by the resource models, in the right order. Finally it accumulates monthly values of the volume, cost, revenue and profit associated with the resource models and defines them as @Risk output variables.

This architecture does not itself involve a mathematical specification. Mathematical specifications will be given for some of the input and resource models in the next two sections.

5. INPUT COMPONENTS – PROTOTYPE

In this section we describe the various input variables or drivers. There are five "input models" associated with the prototype:

- Temperature
- Load
- Hydro energy
- Gas forward and spot prices
- Power forward and spot prices

We will describe load and temperature together but for expository purposes separate gas forward prices and spot prices into separate sections. In each section we will describe the modeling we did to determine an underlying distribution for each variable, or its relation to other variables. We will then describe how we simulate each variable; the simulation should be consistent with the modeling.

The variables' distributions are set up so that their expectations equal the variable values used in a Monet run to support the RVM. These are the "Monet base case" or "Nov. 1" values.

5.1 LOAD (AND TEMPERATURE)

The first important factor influencing net variable power costs is load. Load obviously influences the total power cost; it also influences the unit cost of power, because (all things being equal) higher loads are served on the margin by higher-cost units, and the higher the load the more load has to be served by non-PGE resources. There is generally a very strong correlation between load and temperature, and load and seasonality. Therefore we modeled load as a function of temperature and time in the year, and also temperature as a function of time in the year.

5.1.1 Temperature

We fit temperatures for five years (2000-2004) to a mathematical model; however the model itself was not used as part of the simulation. Rather, only the distribution of errors around the fitted model was used, as a description of the random fluctuations of temperature around the daily normals used in Monet. The mathematical model was of the form:

(1) $$T_t = T_0 + mt + \alpha_1 \cos 2\pi t + \beta_1 \sin 2\pi t + \alpha_2 \cos 4\pi t + \beta_2 \sin 4\pi t + \alpha_3 \cos 6\pi t + \beta_3 \sin 6\pi t + \varepsilon_t$$

where T is the temperature in degrees Fahrenheit, t is the time (in years) since Jan. 1, 2000, and T_0 is an intercept. The m coefficient allows for any recent temperature trends while the α and β coefficients express seasonality (with a yearly period). The model was fit over five years of data assuming all the ε_t were identically distributed. The fitted coefficients were as follows:

T_0	53.18 (0.23)
m	0.59 (0.08)
α_1	-13.42 (0.16)
β_1	-4.80 (0.16)
α_2	-0.47 (0.16)
β_2	2.42 (0.16)
α_3	0.11 (0.16)
β_3	0.04 (0.16)

Having derived the structural model, we computed the standard deviations of the residuals for each month i.e., σ_1 would be the standard deviation of the set of ε_t for all the days in January for 2000-2004, σ_2 would be the standard deviation of the set of ε_t for all the days in February, etc.

Although not all the coefficients in this model are statistically significant (e.g., α_3) the R-squared value of the regression, 82%, appears to be appropriate for a regression. Therefore it is reasonable to use the monthly σ_m values as measurements of the error in a date based temperature forecast – e.g., daily normals – even if we don't use the specific forecasting model above. In order to simulate temperatures around the PGE forecast (taken from a file supplied to us), we simulated the equation:

(2) $$T_t = \hat{T}_t + \varepsilon_t, \quad \varepsilon_t \sim Normal(0, \sigma_{m(t)})$$

where $\hat{T}_t$ is the forecast temperature and *m(t)* is the month associated with day *t*. The structural model derived above was not actually used.

5.1.2 Load

To model load as a function of season and temperature we started with a similar, but somewhat more complex model:

(3) $$\begin{aligned} L_t = L_0 + mt + \alpha_1 \cos 2\pi t + \beta_1 \sin 2\pi t + \alpha_2 \cos 4\pi t + \beta_2 \sin 4\pi t + \alpha_3 \cos 6\pi t + \beta_3 \sin 6\pi t + \\ A_1 T_t + A_2 T_t^2 + A_3 T_t^3 + d \cdot Wkday + \varepsilon_t \end{aligned}$$

where *L* is the daily total PGE load, *t* is the time (in years) since Jan. 1, 2000, *T* is the temperature in degrees Fahrenheit, *Wkday* is a dummy variable that is 1 for weekdays and 0 for Saturdays and Sundays, and L_0 is an intercept. The *m* coefficient allows for load growth over time, the α and β coefficients express seasonality (with a yearly period), the *A* coefficients express temperature dependence, and *d* encapsulates the difference between weekday and weekend loads. This model was fit to five years of data (2000-2004). The fitted coefficients were:

5. Input components – Prototype

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L_0	80590.65 (4110.18)
m	-1115.99 (32.77)
α_1	2623.96 (156.30)
β_1	188.27 (84.60)
α_2	581.91 (73.03)
β_2	217.69 (73.49)
α_3	-66.05 (65.86)
β_3	-428.09 (67.36)
A_1	11.19 (234.30)
A_2	-25.90 (4.34)
A_3	0.29 (0.03)
d	5918.09 (101.51)

As with the temperature model, we computed monthly standard deviations of the residuals, $\sigma_m^{(L)}$.

Note that not all of the coefficients in the above table are significantly different from zero. The most glaring example is α_3. As it happens, and as will be explained below, we actually did not use the time-based (*t*-dependent) part of the structural model.

The fitted load model did not replicate the forecasts $\hat{L}_t$ in the Monet base case, i.e., if we were to forecast load for day *t* based on the normal temperature $\hat{T}_t$ we did not get $\hat{L}_t$:

(4) $$\hat{L}_t \neq L_0 + mt + \alpha_1 \cos 2\pi t + \beta_1 \sin 2\pi t + \alpha_2 \cos 4\pi t + \beta_2 \sin 4\pi t + \alpha_3 \cos 6\pi t + \beta_3 \sin 6\pi t + A_1 T_t + A_2 T_t^2 + A_3 T_t^3 + d \cdot Wkday$$

The goal of this exercise was to estimate the potential variation of net variable power cost around the Monet forecast, assuming that the Monet base case used unbiased forecasts of those uncertain variables. Therefore we normalized the load forecast to the Monet base case:

(5) $$L_t = \left(\hat{L}_t - A_1\hat{T}_t - A_2\hat{T}_t^2 - A_3\hat{T}_t^3\right) + A_1 T_t + A_2 T_t^2 + A_3 T_t^3 + \varepsilon_t^{(L)}, \quad \varepsilon_t^{(L)} \sim Normal(0, \sigma_{m(t)}^{(L)})$$

In other words, the fluctuation of load around its forecast is explained by fluctuations in temperature and an additional normal error. The additional advantage is that the cost simulation will be estimating the cost to serve the same kind of load as Monet, which we believe to be an estimate of the cost-of-service load.

The daily load is converted to 24 hourly loads using a set of scale factors or "scalers". The raw data was again five years' of loads. Each hour was assigned the ratio of its load to the daily total (scaler). Each day was characterized by the month (January to December) and whether it was a weekday (Monday-Friday) or weekend. The scalers were averaged for each hour by month and weekday/weekend indicator. Thus there are 576 scalers (24 hours for 12 months and two daytypes) subject to 24 conditions (for each month and daytype the scalers add to 1). The load for any hour is the simulated load for the day in which the hour occurs, times the appropriate scaler.

5.2 HYDRO AVAILABILITY

We did not have available a consistent set of historical and forecast hydro data. We had three different sets of historical hydro data available – hourly generation from PGE-owned units, daily generation from a set of Federal units, and monthly generation data from the NWPP (including Canada). We used the daily Federal data for the model of power prices described below.

On the other had, we had limited hydro forecast data – basically the information in the 2004 BPA White Book. We constructed a distribution of monthly hydro energy based on two tables from that reference. As a base we used the Water Year (WY) 1937 "Total Hydro Resources" and "Total Surplus/Deficit" for 2006 (Technical Appendix 1, pp. 94-95). To construct a set of variations we used the "Surplus / Deficit by Water Year" from Technical Appendix 1 pp. 122-123. For each water year and month, the monthly energy equaled the WY1937 energy, minus the WY 1937 surplus/deficit, plus the surplus/deficit for the water year under consideration. The fifty water years in the table yield a 50-point discrete distribution for each month, which is converted to a distribution of ratios by dividing by the average over all fifty years (not by the WY1937 value).

The underlying random variable is a vector of 12 monthly energy ratios. Thus, for each iteration of the simulation one of the fifty water years is chosen at random and the ratios for each month of that water year are used. We have no basis to assume any correlation structure across the Northwest, so we assume that every hydro variable is governed by the same ratio. In other words, if the ratio chosen for January is 0.85 then we assume that in January every hydro resource has 85% of its Monet base case energy.

5.3 GAS FORWARD PRICES

To simulate operation costs we would need a model of gas spot prices, but not necessarily forwards. The bulk of PGE's energy comes from hydro and purchases rather than gas so (at least initially) we felt we could ignore gas hedges. However, we did not feel we were able to ignore power hedges. As noted in the next section, we did not have enough historical data on power forwards to construct a model of Mid-C forward prices. We did, however, have enough data on gas prices to construct a model of gas forwards, which we could combine with a model of the relationship between gas and power spot prices to produce an indicative model of the power forward curve. It was therefore important to model the gas forward curve.

Since price simulation is a dynamic process that evolves over time, it is important to maintain consistency in modeling the spot and forward price processes. In Clewlow and Strickland's[3] 1999 paper, they established a consistent model for the entire forward curve. Their price model assumes the forward price is of the form:

(6)
$$\frac{dF(t,T)}{F(t,T)} = \sigma e^{-\alpha(T-t)} dz(t)$$

Here $F(t,T)$ is the forward price on date t for delivery on date T. This equation has two volatility parameters; σ determines the level of volatility for spot and forward price returns, while α determines the rate at which the volatility of increasing-maturity forward prices decline, as well as the speed of mean reversion of the shortest-term price. These two parameters can be estimated from the prices of options on the spot price of energy, or forward contracts.

We estimated σ and α based on a relatively short series of gas prices for delivery at Malin, in order to have a consistent set of forwards. We obtained the annualized values σ=0.553 and α=0.482 ("annualized" means t is measured in years). These parameters were used to simulate the evolution of the forward curve from the Monet base case.

In other words, the Monet base case contained a set of forward prices, which we assumed were as of Nov. 1. The model required a simulated gas forward curve for each day of the following calendar year. The forward curve was simulated according to the formula:

(7)
$$F(t,T) = F(t-1,T) \cdot \exp(\sigma(t,T)\varepsilon_t \sqrt{\Delta t}) \cdot e^{-\sigma(t,T)^2 \Delta t/2}, \quad \varepsilon_t \sim Normal(0,1)$$

where $\sigma(t,T) = \sigma e^{-\alpha(T-t)}$, Δt=1/365.25 (one day). The last term in (3) corrects for the bias introduced when one exponentiates a random variable. It is important to note that this is a "curve" model, because ε_t depends only on t, not T. Furthermore, even though the parameters of the price process were based on Malin prices, which may be biased relative to the prices seen by PGE, the forward curve is evolved from Monet base case prices that should correct for any bias.

5.4 GAS SPOT PRICES

There are several methods one can take in developing a spot price process. The most prominent one is the Geometric Brownian Motion model with mean reversion. One can also add a jump term to the mean reversion process if historical data shows spikes with meaningful frequency, or when the jump term significantly affects the valuation.

The other question of interest is the definition of mean (as to which the mean spot price should revert). One argument is that the spot simulation should preserve the value of forward price, so one can use the forward price as the expected mean. However, the forward price for a given month (the "current month") is frozen at the start of the month; fundamental market

[3] "Valuing Energy Options in a One Factor Model Fitted to Forward Prices", Les Clewlow and Chris Strickland, April 1999.

information about medium-term effects can arrive during the month and should impact the value toward which spot prices revert. A compromise is to use the daily values of the forward price for the following month (the "prompt month") normalized using the forward for the current month.

The prototype model implements this model for spot gas prices. Let t_0 represent the day on which the current month's forward contract closes, T_0 the current month, and T_1 the prompt month. The prototype implements a simulation of the following model for the spot price S(t):

$$
\begin{aligned}
& S(t) = \frac{F(t,T_0)}{F(t_0,T_1)} F(t_0,T_1) \cdot e^{p(t)} \\
& p(t) = (1-\alpha^s)p(t-1) + \varepsilon_t^s + \zeta_t\left((1+v)e^{\delta_t - \gamma^2/2} - 1\right) - B \\
(8) \quad & \varepsilon_t^s \sim Normal(0,\sigma^s) \\
& \delta_t \sim Normal(0,\gamma) \\
& \zeta_t \sim Discrete(1 \text{ with probability } \Lambda \cdot \Delta t, 0 \text{ otherwise})
\end{aligned}
$$

In the equation for p(t), the first term represents persistence with some reversion to 0, the second is a standard diffusion (geometric Brownian motion) and the third is a jump. The jump probability is $\Lambda \cdot \Delta t$ and the jump amplitude is lognormal. The fourth term (B) is the bias introduced by the reversion coefficient and exponentiation; it has a rather complex form:

$$
(9) \qquad B = \Lambda \cdot v \cdot \Delta t + 1/2\left(\sigma^{s^2} + (1+v)^2 \Lambda \cdot \Delta t\left(e^{\gamma^2} - 1\right) + v^2 \Lambda \cdot \Delta t(1 - \Lambda \cdot \Delta t)\right)\left(1 - \alpha^s(1-\alpha^s)\right)
$$

The superscript *s* on σ^s and α^s is to distinguish them from the similar parameters in the forward price process.

σ^s and α^s were estimated using approximately one year of *Gas Daily* prices at Malin. They were actually taken from a simpler version of (8):

$$
\begin{aligned}
& y_t = -\hat{\alpha} x_t + \varepsilon, \ \varepsilon \sim Normal(0,\hat{\sigma}) \\
(8a) \quad & \text{where } x_t = \ln\left(\frac{S(t)}{F(t,T_1)}\right) \text{ and } y_t = x_t - x_{t-1}
\end{aligned}
$$

We fit model (8a) using an available set for prices spanning the period from Dec. 13, 2004 to Nov. 30, 2005. The dataset contained 253 observations at an average separation of 1.39 days, i.e., Δt=0.00381 years. The estimate for $\hat{\alpha}$ was 0.0341 with a standard error of 0.048. We annualized it by dividing out Δt: $\alpha^s = \hat{\alpha}/\Delta t$ = 89.47. The standard deviation of the residuals was $\hat{\sigma}$ =4.98%; we annualized it (in this case dividing by $\sqrt{\Delta t}$) to get $\sigma^s = \hat{\sigma}/\sqrt{\Delta t}$ =80.6%. Again, the fact that the prices are based on a simulated PGE forward curve should correct for locational biases.

Calibrating a jump model is quite difficult, so we did not do so for this analysis. We used values we consider to be representative: Λ=6, v=0.8 and γ=0.05. We believe the use of these "typical" values is sufficient for prototyping the cost simulation model.

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Note that by using a single gas price, and modeling it based on forwards, we are representing less detail Monet, which uses separate locational prices for gas for Beaver and Coyote called GAS_PGE_1 and GAS_PGE_CS respectively, with a basis differential of from $0.08 to $0.33. We based the gas prices in the prototype on GAS_PGE_1, that is, we used the monthly values of that price in Monet as the Nov. 1 forward curve, allowed it evolve under the models described in this section, and used the result for both Beaver and Coyote. This is acceptable for prototyping the simulation; a production version ought to use different locational gas prices for the two plants.

5.5 POWER SPOT AND FORWARD PRICES

A key issue in the determination of net variable power costs is the relationship between power costs and other underlying cost drivers. This is particularly important because while we had a good historical dataset for Mid-C spot power prices, including the "crisis period" of 2000-2001, we did not have a good dataset for Mid-C forward prices. We felt it was important to include the crisis period in our model of power prices, more so than for gas prices – the crisis had to do with the relationship between power and other prices, since currently gas prices have been high without power prices spiking as much as in 2000-2001. If the model of the relationship between power prices and other prices, especially gas prices, did not include the crisis period we felt it would "over-fit", that is, the uncontrolled and independent influences on power prices would be understated.

5.5.1 Spot price model

We identified three key drivers of power prices to test: gas prices, hydro energy availability and load. The power price of interest is the price at Mid-C, which is a regional hub, so the price should represent regional conditions. Therefore we felt we should consider regional hydro availability and regional load as explanatory variables.

- Regional hydro energy was obtained from a dataset obtained from PGE containing 8 years' worth of daily generation from major plants in the Northwest, which we referred to as the "Federal" dataset. Unfortunately this dataset ended in 2002 and no continuation was available.
- Regional load was obtained from the EIA database of FERC form 714 responses. This database contains hourly loads and we summed the loads for all the reporting utilities in NWPA.
- For gas prices we used historical daily prices at Stanfield OR as reported by Bloomberg.
- The independent variable (power prices) was represented by historical daily prices at Mid-C as reported by Bloomberg. We had data on both peak and offpeak prices.

We tested several different models for peak power prices, selecting the "best fit" based on R^2. The models were distinguished by whether they used raw values of the variables, or their logarithms. We further tested several different error models beginning with ordinary least squares (OLS). A Durbin-Watson test indicated the presence of autocorrelation so we tried an autoregressive error model with one lag (AR(1)), autoregressive with two lags (AR(2)), and an AR(2)-GARCH(1,2) model. In PA's judgment the best of these is the AR(2) model with all variables represented by their logarithms:

(10)
$$\ln PP_d = LPP_0 + a \ln GP_d + b \ln PL_d + c \ln H_d + \varphi_d$$
$$\varphi_d = A_1 \varphi_{d-1} + A_2 \varphi_{d-2} + \varepsilon_d$$

In this specification, PP_d is the peak power price on day *d*, GP_d is the gas price, PL_d is the total load over peak hours, H_d is the hydro energy, and φ_d is the error; the actual random shock is ε_d. All variables are significant at a 95% confidence level (even 99%). The model coefficients are:

LL_0	-4.736 (0.592)
a	0.501 (0.070)
b	1.850 (0.141)
c	-0.578 (0.073)
A_1	-0.738 (0.024)
A_2	-0.231 (0.024)

The standard deviation of the shock ε_t is 0.200. The R^2 of the autoregressive model is quite high at 95.9%.

When we performed a similar regression for offpeak power prices, the coefficients for offpeak load and hydro energy were not significantly different from zero; however, if we used the onpeak load as an explanatory variable, its coefficient was significant. Since the onpeak load influences onpeak price, we tested a regression of offpeak prices on onpeak prices, which seems to work best:

(11)
$$\ln OP_d = LOP_0 + a' \ln PP_d + \delta_d$$

The model coefficients are:

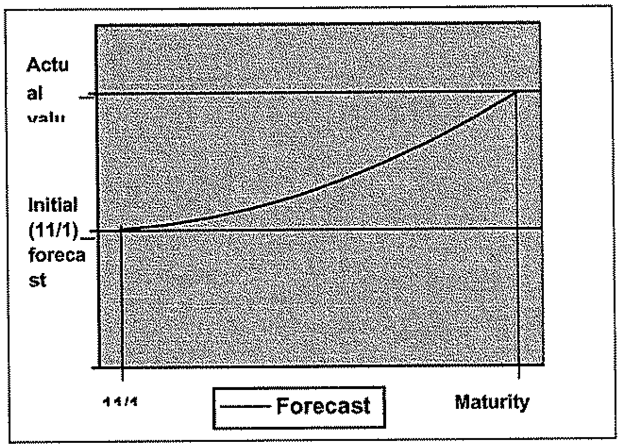
LOP_0	-0.232 (0.029)
a'	0.974 (0.008)

The standard deviation of δ_d is 0.302. The R^2 of this model is 91.1%|. Given that high value of R^2, and the fact that the independent variable (ln PP_d) is already autoregressive, we did not use estimate (11) with an autoregressive error model.

5.5.2 Use of spot price model to construct forward curves

We assumed that forward prices depend on forward versions of these same drivers, in the same way as spot prices. Thus, for example, the price for August power as of March 15 should depend on the August gas forward as of March 15 and the load and hydro energy expected, on March 15, to be realized in August (at the "maturity date").

Unfortunately, the model only simulates the values load and hydro energy and not the accretion of information about hydro conditions or the evolution of load forecasts. In order to construct power forward curves as well as to model hedge rebalancing (discussed below) we require a model of the *information arrival process.* In order to drive the prototype we use a quadratic model of information arrival. The graph below shows how a forecast would increase over time to meet the actual value:



Essentially at any date t between the date of the base case forecast (which is Nov. 1, denoted t_0) and the maturity date T, the state of knowledge of variable v_T is assumed to be

(12) $$v_T^{(t)} = v_T^0 + \left(\frac{t-t}{T-t}\right)^2 \left(v_T - v_T^0\right) = k(v,T,t)$$

We use the following formula as an estimate of the onpeak power forward price as of day *d* for delivery on day *D* (denoted PF(d,D); PF(0,D) is the monthly forward price from the Monet base case – as of Nov. 1 –GF(d,D) is the gas forward and PL_D^0, H_D^0 are the base-case expectations of load and hydro availability respectively):

(13) $$\begin{aligned} &PF(d,D) = PF(0,D)\cdot\left(GF(d,D)/GF(0,D)\right)^a \left(k(PL,D,d)/PL_D^0\right)^b \left(k(H,D,d)/H_D^0\right)^c e^{\varphi_d - B} \\ &\varphi_d = A_1\varphi_{d-1} + A_2\varphi_{d-2} + \varepsilon_d \end{aligned}$$

Here B is a bias due to all the exponentiation. We were not able to come up with a closed-form representation for B analogous to (9) so we estimated it by simulating (13) setting B=0, and then letting B be the ratio of its expectation to PF(0,D). Actually, rather than using a table of B values for all possible parameters *d* and *D*, we fit a linear function of the form

(14) $$B(d,D) = \mu\left(\frac{D-d}{D-t_0}\right) + \beta = \mu' d + \beta'$$

The offpeak power forward price, OF, was simulated using:

(15) $$OF(d,D) = OF(0,D)\cdot\left(PF(d,D)/PF(o,D)\right)^{a'} e^{(\delta_d - V\delta/2)}$$

where $V\delta$ is the variance of δ_d.

5. Input components – Prototype

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Finally, daily average peak and offpeak power prices were simulated using similar formulas but based on the actual gas price, hydro availability and load rather than forwards and "partial knowledge" values (PP_d^0, OP_d^0, GP_d^0 are the values used in the Monet base-case forecast):

(16) $$PP_d = PP_d^0 \cdot \left(GP_d / GP_d^0\right)^a \left(PL_d / PL_d^0\right)^b \left(PL_d / H_d^0\right)^c e^{\varphi_d - B}$$

(17) $$OP_d = OP_d^0 \cdot \left(PP_d / PP_d^0\right)^{a'} e^{\delta_d}$$

Here φ_d and δ_d are as in equations (13) and (15). In equation (16) B is a bias similar to the bias in (13) and, similarly, was assessed empirically.

Hourly spot prices were computed from the peak and offpeak averages using scalers, similar to the load scalers described above.

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6. RESOURCE MODELS – PROTOTYPE

In this section we describe the various resources. A "resource" is anything that contributes positively or negatively to the net variable power costs. Load is a resource, as are generators; the market-based cost associated with serving load is netted out against the profits obtained by selling generated energy into the market. In other words, the cost simulation is a "mark to market" model.

There are eight "input models" associated with the prototype:

- Load
- Beaver power plant
- Coyote power plant
- Boardman power plant
- Colstrip power plant
- Mid-C hydro contracts
- Portland General hydro resources
- Forward hedges

Some of these resources were modeled using the same DLLs as in Monet, although in one case (Coyote) we used a much simpler model because the DLL took too long to run. We will explain the simplification used as well as the tests carried out to check the impact of the substitution.

For every iteration the model records 180 items of information for each resource. For each month it records:

- MWh (generation or load) – peak, offpeak and total
- Average MW – peak, offpeak and total
- Total fuel or contract cost – peak, offpeak and total. This applies to power plants, which obviously have fuel costs, but also forward hedges, for example, the cost of a swap is the fixed price swapped for the market price. It does not apply to load, which only has a cost based on spot power.
- Total revenue or cost at spot power prices – peak, offpeak and total.
- Net profit (revenue minus costs) – peak, offpeak and total. The net variable power costs is the (negative of the) sum of the monthly net profit figures.

6.1 LOAD

The resource model for load is quite straightforward. The simulated load (described in 5.1) is multiplied by the simulated Mid-C price for each hour, which represents a negative value for "revenue at spot power price".

6.2 BEAVER POWER PLANT

The operation of the Beaver plant is simulated by dynamic programming using the same DLL (bcdispatch.dll) and subroutine (dll_bcd_optimize) as in the Monet model. The operating states, transition matrix, capacities, heat rates and O&M costs were taken directly from the Monet base case. This demonstrates the ability to use Monet components directly.

The DLL is used to dispatch the plant based on simulated gas prices and Mid-C power prices. The "fuel cost" in each hour is actually the sum of the fuel and VOM costs.

6.3 COYOTE POWER PLANT

We initially modeled the Coyote plant as for Beaver, using the same dynamic programming routine as in the Monet model. However, it became clear that because of the size of the Coyote model – 492 states based on 6 separate operating states and 72-hour minimum uptime – it took too much time to run. It would not be reasonable to run a Monte Carlo simulation involving such a complicated operational model.

We constructed a grossly simplified Coyote model, where each day the plant either runs or not, and if it runs then in each hour the model can freely choose any of the six operating states (minimum load; mid load; maximum steam turbine load (full load); full load plus misting; full load plus misting and duct burner; and full load plus misting and duct burner with no steam extraction). One might argue that in optimal daily cycling the plant would not run in offpeak hours, but since its minimum uptime is 72 hours it does have to run in offpeak hours for most of its operating days. We call this the "daily commit" model.

We also constructed a somewhat less grossly simplified model based on weekly commitment: the commitment decision would be made for a week at a time, and for each week the plant would follow one of four patterns: on all week, on from 7AM Monday through 10PM Friday, on from 7AM Monday through 10PM Saturday, or off all week. The first few hours could be adjusted if needed to transition from the previous week's end state, respecting the plant's startup and cooldown ramp rates. In each operating hour the model would freely choose any of the six operating states. We call this the "weekly commit" model.

We tested this simplified models against 100 iterations of the prototype input models. In other words we ran a Monte Carlo simulation of the input variables for 100 iterations (actually these were early versions of the input models) and dispatched each Coyote model against each set of inputs. We then compared the annual total "net revenue" from each of the simplified models against the original dynamic programming (DP) version using linear regression. In other words, we estimated the following two models by regression:

(18) $$NetRevenue(DP) = a \cdot NetRevenue(DailyCommit) + b + \varepsilon$$

(19) $$NetRevenue(DP) = a' \cdot NetRevenue(WeeklyCommit) + b' + \varepsilon'$$

ε, ε' are normally distributed errors. The coefficient values (with standard errors) and R-squareds were:

	Daily Commit	Weekly Commit
Intercept (b)	-4070(150)	1649(72)
Coefficient (a)	1.055(0.0045)	0.9799(0.0024)
R^2	99.8%	99.9%

Both simplified models appear to be quite good predictors of, and therefore acceptable substitutes for, the full dynamic programming model. What is most important is that they are much more efficient: each ran in about 1.5% the time of the DP model. For the results reported below we used the "Daily Commit" model, which is simpler to implement and easier to understand.

6.4 BOARDMAN POWER PLANT

The Boardman plant was modeled assuming daily cycling: it could start any hour from 1 to 7, and shut down any hour from 22 to 24, or not run at all (or be on forced outage). While running it was allowed to run either at minimum or maximum loading. The ownership fraction (65%), operating characteristics, forced outage rate and coal prices were taken from the Monet base case. The only random variable that impacts Boardman is its outage status (available or on outage).

6.5 COLSTRIP POWER PLANT

The Colstrip plant was modeled as two units (3 and 4) with slightly different characteristics (Colstrip 4 had more capacity in the summer and a lower coal cost in the second half of the year). Those characteristics, as well as the forced outage rates, coal prices and ownership fractions (20% of each) were taken from the Monet base case. Both units were allowed actually to cycle hourly, which appears to be how Monet models them. The only random variables that impact the Colstrip units are their outage statuses (available or on outage).

6.6 PORT WESTWARD POWER PLANT

The Port Westward plant was not modeled, since it was not included in the M606PUC05-105-06.xls Monet run we were using as a comparative, and it does not contribute to 2006 net variable power costs. The modeling of the Beaver, Coyote, Boardman and Colstrip should have been sufficient to demonstrate the ability of this modeling approach to represent fossil-fired generators.

6.7 MID-C HYDRO CONTRACTS

The four Mid-C contracts – Priest Rapids, Rocky Reach, Wanapum and Wells – were modeled as a single dispatchable hydro plant, with energy specified monthly and the obligation to provided reserves to cover PGE's other generation. This dispatch modeling was done by dynamic programming using the same DLL (midccomp.dll) and subroutine (dll_midc_optimize) as in the Monet model. All the parameters describing the contracts, and the base-case monthly energy and capacity, came from the Monet base case; however, for each iteration of the simulation model the monthly values were multiplied by the vector of hydro availabilities (see 5.2). Note that both energy and capacity are multiplied by the same scaling value.

6.8 PORTLAND GENERAL HYDRO RESOURCES

There are nine other PGE-owned or –contracted hydro resources: Round Butte, Pelton, Oak Grove, North Fork, Faraday, River Mill, Bull Run, Sullivan, Portland Hydro Project. The Monet model represents each of them with a set pattern of hourly releases based on weekly, monthly and hourly factors; they do not respond to load or prices. We modeled them as depending only on hydro availability, using the same hydro availability as for Mid-C: for each simulation iteration, each hourly generation value is multiplied by the hydro availability for that month.

6.9 FORWARD HEDGES

From our discussions with PGE staff as well as regulators it became clear that it would be important to allow the model to represent a hedge rebalancing process, whereby PGE modifies its hedge portfolio through the year. As it was described to us, PGE does not (by policy) rebalance its hedge portfolio in response to price movements but in response to its evolving view of its short position. This in turn can depend on price movements – increases in the spark spread should encourage greater operation of Beaver, Coyote, Boardman and Colstrip, and reduce the short position.

Specifically it is our understanding that by Nov. 1 PGE is 90% hedged for the coming year. The hedges are a mix of forwards and options; for simplicity the prototype model represents only options. During the year, PGE rebalances the hedges and increases the coverage to 100%. The rebalancing is based on PGE's forecast of its short position and therefore requires the same kind of information arrival modeling as does the power forward curve model (see 5.5.2). In this case we also allow for an error in PGE's forecast of its short position; that is, the arriving information can be incorrect.

Basically we assume that as of Nov. 1 PGE fills 90% of its expected short position L^0. Then on day d, PGE purchases an additional amount of energy for each forward month *M* equal to *k(L', M, d)*. Here L' represents a "perturbed" or unreliable estimate of the net short position and k() is the same quadratic information arrival process as in 5.5.2.

Specifically, for each iteration the net short position (load minus all generation) in month M could be exactly computed as L_M. We assume there is a random error in forecasting L_M; the forecast F_M is normally distributed with mean L_M and standard deviation equal to 2% of L_M. The 2% figure is an assumption made just to drive uncertainty into the modeling. On day d, then, enough additional forward contracts for month M are bought to bring the total position to

$$(20) \qquad \left\{0.9+0.1*\left(\frac{d-d_0}{M-d_0}\right)\right\}\left(L_M^0+\left[\left(\frac{d-d_0}{M-d_0}\right)^2\right]\left(F_M-L_M^0\right)\right)$$

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The term in curly brackets {} is the fraction of the load forecast that is expected to be filled by day *d*; it grows linearly from 0.9 to 1.0. The term in square brackets [] is the information arrival coefficient.

Note that the forward rebalancing for each iteration needs to be evaluated *after* the input variables have been simulated and the other resource models computed, because it depends on the short position ("filtered" using the information arrival coefficients). The forecast short position is a clouded view of the actual short position in each iteration, which depends on the energy produced by each resource. Therefore the resource models have to be executed, to provide their actual energy values, prior to computing the forward rebalancing.

7. PROTOTYPE RESULTS

PA constructed a prototype of the cost simulation model in order to demonstrate the behavior one can expect from such a model and the range of analysis possible with it. Two advantages of the modular "sandbox" construction were apparent early on, namely the ability to isolate and correct individual model components easily, and the ability to test and substitute different or simpler versions of a component model (such as the Coyote model noted above).

We first tried to compare the results of the cost simulation model with the Monet base case run. To do so we substituted the Monet gas and power prices for the price models in the simulation model and set relative hydro energy for each month to 1 (expected value). The prototype results were not the same as Monet's. This could have been due to errors in the simulation model, which was only a proof of concept rather than a polished model.

The simulation model reported nonzero energy costs associated with the PGE hydro units. These nonzero costs were variable O&M reflecting the O&M costs found in the Monet model, ranging from $0.19/MWh for North Fork and Faraday to $5.02/MWh for Round Butte. Monet reports no O&M costs for any plant, and no costs at all for any PGE hydro resources or contracts except Portland Hydro Project and the Mid-C plants. The costs reported for those plants are fixed contract costs.

The following table summarizes the differences between Monet and the prototype's "base case":

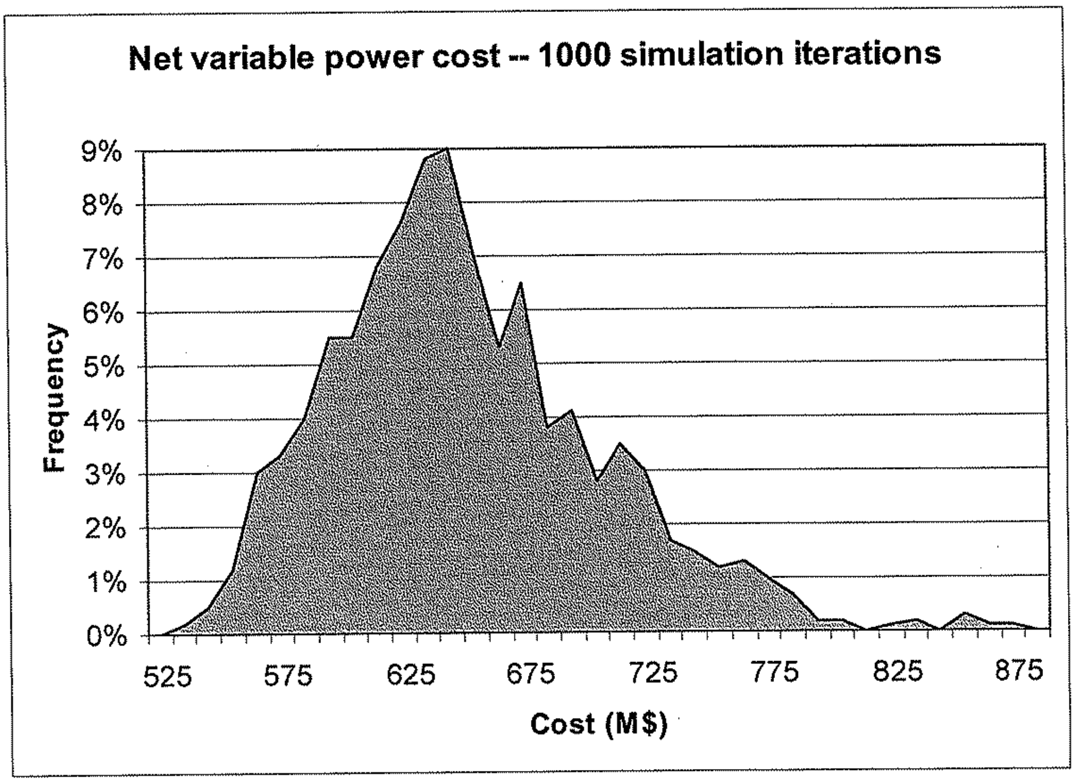
	Monet		Cost simulation prototype with Monet prices	
Resource	Cost (K$)	Energy(GWh)	Cost (K$)	Energy(GWh)
Coyote	66,645	1,183	64,667	1,073
Beaver	9,867	128	-	-
Mid-C	*	2,848	8,978	2,993
Boardman	35,484	2,867	14,223	2,760
Colstrip	14,133	2,087	20,181	2,278
PGE Hydros	4,293	1,992	4,788	2,056
Total market	509,347	8,528	528,105	9,104
Spot	93,256	1,454	528,105	9,104
Hydro contracts	38,759*	N/A	*	
Fwd/other	377,332	7,073	**	
Total	639,770	19,633	640,943	19,633

*-Monet does not really report a variable cost for the Mid-C plants; it reports only a fixed contract charge. That charge has been incorporated into the "market" number below. The simulation prototype, on the hand, reports the variable O&M costs for the Mid-C plants (and in fact it includes variable O&M in each plant's costs). The simulation does not report the fixed costs of the Mid-C contracts, or any other long-term contracts already in the Monet file. On the other hand, Monet does not report variable O&M.

**-Since there was no evolution of forward prices in the base case, all market prices are spot.

Some of the differences between the prototype simulation model and the Monet base case are due to modeling differences, for example the simplified Coyote dispatch. Others are due to its "prototype" nature; we had a limited amount of time to ensure a perfect match between the model and the base case.

Despite these differences, it is useful to examine the prototype results in more detail to see what kind of insights a model of this type might eventually be able to provide, keeping in mind its simplified and prototype nature. The following figure gives the histogram of results from a 1000-iteration run of the cost simulation prototype:



Visually the distribution appears quite skewed. Estimates of its statistical parameters are:

Median (M$)	643.73
Mean (M$)	650.86
Standard deviation (M$)	55.10
Skewness	0.697
(Excess) kurtosis	0.669

The last two items are dimensionless measures of the shape of the distribution. The positive skewness indicates that the distribution is asymmetric, with much more significant outliers to the right (higher costs). Thus its mean is to the right of (greater than) its median. The positive kurtosis indicates the distribution has a higher peak and "fatter tails" than a normal distribution, in other words, that the departures from the mean are likely to be larger than in a normal distribution.

It is often tempting, when facing a skewed distribution like the one above, to assume that it fits a lognormal rather than normal distribution (both the skewness and kurtosis of a normal distribution are zero). In fact this distribution is significantly more skewed and has fatter tails than a lognormal distribution: the corresponding parameters of a lognormal distribution with this mean and standard deviation are 0.255 (skewness) and 0.115 (kurtosis).

One must use these numbers with care. As noted earlier, many of the parameters underlying the simulation are only imprecisely estimated; in many cases the data used in computing the estimates are only proxies for the values whose properties were being estimated. Furthermore the model itself is a prototype constructed in such a way as to make it easier to test different estimation or approximation techniques. Section 3.3.1 drew a distinction between descriptive and prescriptive models; this prototype is of the descriptive class.

The numbers themselves are estimates of the statistics of an underlying cost distribution, not the statistics themselves, and they may be subject to bias or error. For example, the $55.10 million "standard deviation" is really the square root of the sample variance. The sample variance is generally an unbiased estimator of the variance – that is, tends neither to under nor overestimate it – but its square root is actually a biased estimator of the standard deviation, so that the standard deviation is probably somewhat more than $55.10 million.[4]

The $55.10 million also understates the variability in power costs because the simulation parameters are themselves uncertain. Recall that several of the input variables were represented using parametric statistical models to capture their interrelationships. The parameters were estimated from historical data, necessarily with some uncertainty. (The uncertainty in the estimation is also a proxy for the possibility that the wrong family of statistical models was used.)

The flexibility of the simulation prototype allows us to get a feel for the additional variability introduced by that parameter uncertainly. We simulated the impact of uncertainty in just one of the input models, the model of peak power prices (equation (10) on page 5-30). The table of coefficients for that equation indicates the standard error of each estimate. We ran twenty separate 100-iteration simulations using the cost simulation, with different values of those coefficients: for each run the coefficient values were chosen from normal distributions with the associated mean and variance. A scatter plot of the results follows:

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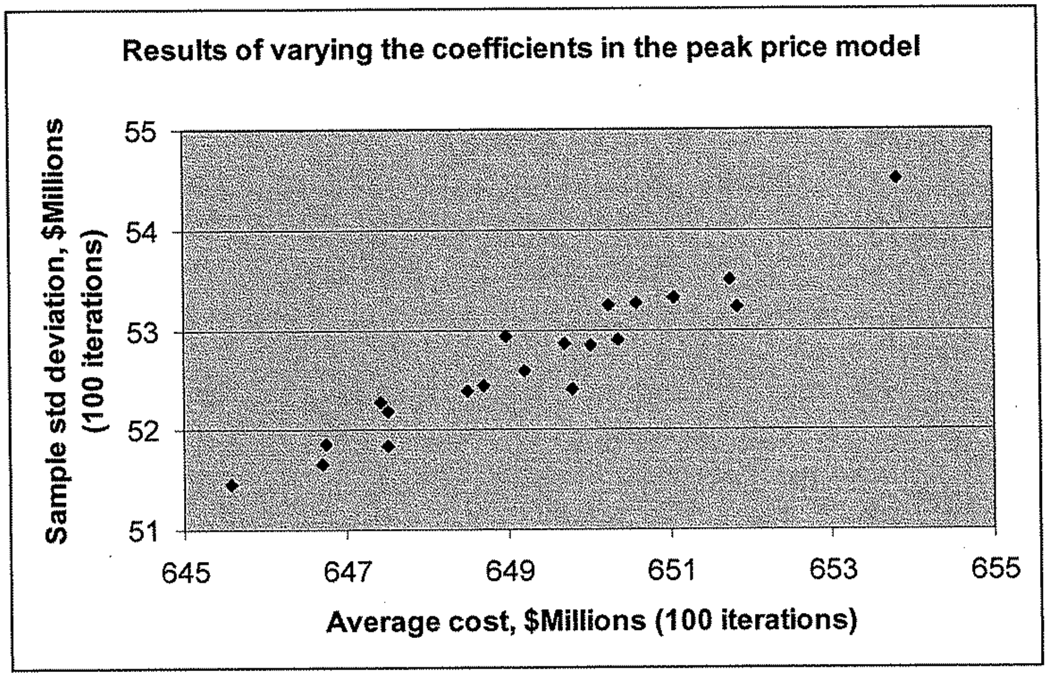
[4] See, e.g., S. L. Sclove, "Concerning the Sample Standard Deviation," University of Illinois – Chicago, http://www.uic.edu/classes/idsc/ids571/samplvar.pdf as of 5/16/06. Specifically, if the sample variance is denoted S^2, so that its square root is S, and the (underlying) standard deviation is σ, then $E(S^2)=\sigma^2$ but $(E(S))^2 = E(S^2) - Var(S^2) < E(S^2)$.



The simulated costs from these twenty runs ranged from $645.6 million to $653.8 million. The uncertainty attributable to this parameter model, as well as the uncertainty in other parameter models, contributes positively to the uncertainty in net variable power cost.

This cost simulation model can *qualitatively* indicate the degree to which there is a greater-than-normal risk of bad outcomes (high costs). Here "normal" really means both "in a normal distribution" and "anticipated in the normal course of life". Without using the specific numerical values produced by this simulation it is clear that there is significant cost risk: the distribution is quite positively skewed and leptokurtic. The prototype simulation model indicates that PGE's risks are magnified relative to an estimate based on normal distributions.

The standard deviation of the distribution is $55 million, not a trivial sum even though it is only about 8.5% of the expected costs. Given the amount of hedging assumed in the model, 8.5% is a quite significant variation. It is almost as large as PGE's total net income for 2005 ($64 million) or 2003 ($60 million as restated) and 60% of PGE's net income for 2004 ($92 million).[5] Furthermore, the difference between the expected value of $650.86 million and the base case value of $640.94 is positive and statistically significant ($p>.999$). We had expected that the relationship between hydro conditions and price (in poor hydro conditions more load is exposed to high power prices) would move the mean, and we had been quite surprised when the effect did not show up in an earlier version of the prototype. That serves to demonstrate the dangers of drawing definitive conclusions from early versions of a mathematical model.

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[5] Net income figures are from Portland General Electric's Annual Report on Form 10-K filed March 16, 2006.

Although the power price model described in section 5.5 included gas and load as explanatory variables as well as hydro conditions, on a monthly or annual basis the only variable significantly correlated with power prices is hydro energy. The following table gives the correlations observed between the simulated series of various input variables. Recall that the prototype included some complex models for and dependencies among the input variables (sections 5.3-5.5).

CORRELATIONS OF MONTHLY AND ANNUAL AVERAGES OF UNCERTAIN VARIABLES

Month	Load & Peak price	Load & Gas price	Load & Hydro	Peak price & Gas price	Peak price & Hydro	Gas price & Hydro
January	18%	3%	-3%	19%	-85%	0%
February	11%	-1%	-2%	11%	-90%	-1%
March	14%	-1%	-3%	18%	-89%	-4%
April	13%	3%	-2%	17%	-89%	-1%
May	8%	4%	2%	15%	-90%	-1%
June	11%	0%	-3%	20%	-87%	-5%
July	18%	1%	0%	19%	-83%	-4%
August	22%	-2%	-3%	23%	-72%	1%
September	20%	-2%	-6%	15%	-74%	3%
October	9%	-3%	4%	17%	-64%	3%
November	25%	-3%	-2%	20%	-52%	4%
December	16%	-2%	1%	14%	-76%	1%
Total	10%	2%	-4%	14%	-96%	-2%

In order to understand the influence of various variables on the results of the cost simulation, we performed linear regressions of the simulated cost for each month on the average load in that month, average peak period power cost, average gas cost, and relative hydro energy. To put all variables on a common footing they were normalized to have mean zero, unit standard deviation (the means were subtracted and the result divided by the standard deviations). We also included interaction terms. Thus, for each month of the simulation we fit the model:

$$\begin{aligned}\text{Cost} = {} & a^*\text{Load} + b^*(\text{Peak Price}) + c^*(\text{Gas Price}) + d^*\text{Hydro} + e^*\text{Load}^*(\text{Peak price}) \\ & + f^*\text{Load}^*(\text{Gas price}) + g^*\text{Load}^*\text{Hydro} + h^*(\text{Peak price})^*(\text{Gas price}) + \\ & k^*(\text{Peak price})^*\text{Hydro} + m^*(\text{Gas price})^*\text{Hydro} + C_0 + \varepsilon\end{aligned}$$

where a, b, c, d, e, f, g, h, k and m are the model coefficients, C_0 is an intercept and ε is a normally distributed error. The following table gives the coefficient values and standard errors (in parentheses), where coefficients in **bold** have a statistically significant difference from zero (at the 95% confidence level) and coefficients in normal font do not:

7 Prototype results

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Month	Avg Load	Peak Price	Gas Price	Hydro	Load * Peak price	Load * Gas price	Load * Hydro	Peak price * Gas price	Peak price * Hydro	Gas price * Hydro	Intercept
January	**2.03** **(0.14)**	**-0.85** **(0.31)**	**4.71** **(0.15)**	**-9.88** **(0.29)**	0.06 (0.27)	**0.66** **(0.15)**	-0.24 (0.28)	**-1.19** **(0.24)**	**-1.15** **(0.13)**	**-2.99** **(0.24)**	**68.30** **(0.18)**
February	**1.31** **(0.07)**	**-0.50** **(0.19)**	**3.07** **(0.07)**	**-9.72** **(0.18)**	-0.07 (0.17)	0.13 (0.07)	-0.06 (0.18)	-0.13 (0.10)	**-0.70** **(0.08)**	**-1.36** **(0.10)**	**52.56** **(0.09)**
March	**1.15** **(0.05)**	0.13 (0.12)	**1.51** **(0.05)**	**-5.44** **(0.11)**	-0.07 (0.12)	-0.06 (0.05)	-0.05 (0.11)	0.08 (0.06)	**-0.29** **(0.06)**	**-0.59** **(0.06)**	**55.58** **(0.06)**
April	**0.85** **(0.04)**	-0.08 (0.10)	**1.38** **(0.04)**	**-5.12** **(0.09)**	0.07 (0.09)	0.00 (0.04)	0.03 (0.09)	0.02 (0.05)	**-0.23** **(0.04)**	**-0.63** **(0.05)**	**42.90** **(0.04)**
May	**0.55** **(0.04)**	-0.05 (0.09)	**0.91** **(0.04)**	**-4.04** **(0.08)**	0.14 (0.08)	-0.01 (0.04)	0.06 (0.08)	0.00 (0.04)	**-0.13** **(0.03)**	**-0.43** **(0.04)**	**44.91** **(0.04)**
June	**0.58** **(0.03)**	-0.08 (0.07)	**0.82** **(0.03)**	**-3.66** **(0.06)**	0.08 (0.06)	**-0.10** **(0.03)**	0.03 (0.06)	0.06 (0.03)	**-0.19** **(0.03)**	**-0.32** **(0.03)**	**37.05** **(0.03)**
July	**1.40** **(0.05)**	**-0.52** **(0.10)**	**3.00** **(0.05)**	**-4.49** **(0.10)**	0.15 (0.10)	-0.08 (0.05)	0.09 (0.10)	0.03 (0.06)	-0.03 (0.05)	**-0.55** **(0.06)**	**54.54** **(0.06)**
August	**1.55** **(0.07)**	**-0.72** **(0.10)**	**4.26** **(0.07)**	**-2.95** **(0.10)**	-0.17 (0.10)	**-0.19** **(0.06)**	-0.11 (0.10)	**0.17** **(0.07)**	**-0.19** **(0.06)**	-0.11 (0.06)	**59.62** **(0.07)**
September	**0.94** **(0.06)**	**-0.19** **(0.09)**	**2.39** **(0.06)**	**-2.66** **(0.09)**	0.02 (0.08)	**-0.21** **(0.06)**	0.03 (0.09)	0.07 (0.05)	0.01 (0.06)	**-0.31** **(0.05)**	**55.69** **(0.06)**
October	**0.74** **(0.06)**	**-0.29** **(0.08)**	**3.62** **(0.07)**	**-2.31** **(0.09)**	0.13 (0.08)	-0.04 (0.07)	**0.23** **(0.08)**	**-0.17** **(0.07)**	-0.11 (0.08)	**-0.59** **(0.06)**	**54.69** **(0.07)**
November	**1.47** **(0.08)**	-0.02 (0.09)	**3.93** **(0.08)**	**-2.46** **(0.09)**	-0.06 (0.09)	0.01 (0.08)	0.10 (0.09)	-0.15 (0.09)	0.02 (0.08)	**-0.88** **(0.08)**	**56.32** **(0.08)**
December	**1.70** **(0.09)**	0.19 (0.15)	**4.83** **(0.09)**	**-5.44** **(0.15)**	0.06 (0.15)	**0.25** **(0.10)**	0.19 (0.14)	0.10 (0.13)	-0.05 (0.10)	**-1.07** **(0.13)**	**66.94** **(0.11)**
Total	**3.98** **(0.51)**	2.56 (2.05)	**29.56** **(0.54)**	**-39.20** **(1.98)**	1.81 (1.89)	-0.01 (0.53)	0.93 (1.90)	-0.99 (0.72)	**-1.29** **(0.48)**	**-7.01** **(0.70)**	**649.82** **(0.61)**

Note: values in parentheses are standard errors, not p values.

On a monthly basis, hydro condition is the most important determinant of net variable power cost. Although the coefficient on the interaction term between peak price and hydro energy is significant, it is still quite small compared with the intercept, so that the interaction will not have a large effect. In fact, the interaction between gas price and hydro conditions appears to be more important, especially in January and on an annual-average basis. Especially during the first half of the year, in low hydro conditions it appears that increased use of gas-fired plants may be limiting the impact of power price increases.

8. USES OF A COST SIMULATION MODEL TO SUPPORT THE REGULATORY PROCESS

During the course of this project, Portland General Electric staff explained to PA some of the context in which the project was initiated. Apparently there have been discussions between Portland General and the Public Utility Commission of Oregon about the variability in PGE's power costs, and whether it is appropriate for ratepayers to cover that variability, at least in part, through an annual true-up. If there were no true-up then PGE shareholders would bear that risk, providing cost insurance to ratepayers.

In addition to the public policy question of appropriateness, there are several analytic questions that one might try to address with a cost simulation model, e.g., how large is the risk and whether one can compute a risk adjustment to the revenue requirement to compensate the utility for bearing it. This project was initiated to determine how to structure a model that could answer the first of those questions, and whether such a model could also answer the second.

Utilities are generally given the opportunity to earn a return, but not a guarantee that the return will be earned. The return is put at risk to the utility's operational performance and to factors under the control of utility management. Whether fuel price risk, for example, is appropriately placed on the utility may depend on the tools the utility has or has not been given with which to mitigate it. Certain risks may just be too large for the utility reasonably to mitigate. In that case ratepayers, with greater overall financial resources, may appropriately be asked to bear the risk. A simulation model can help characterize the size of the risk.

Using our prototype model we have estimated the standard deviation, that is, the typical range of variation, in net variable power costs. We arrived at a figure of $55.1 million. This figure may not be accurate – it could easily be off by, say, $10 million either way. But we can still make a qualitative statement that the risk is quite sizable. At $55 million, the standard deviation is over half the company's net income in any of the last three years. Suppose the standard deviation of net variable power costs actually were $50 million. If the net variable power costs were normally distributed, there would be a 10% chance that the costs would exceed the net income in two of those three years. Because the cost distribution is positively skewed and fat-tailed the probability is actually greater than 10%.

Uncertainty in the estimate of standard deviation would make it very difficult to use the numerical results of this prototype for ratemaking or to determine a "risk adder". The same problem might apply to other simulation models. As with the Black-Scholes model it is actually quite difficult to calibrate a model that depends on distributional inputs. Therefore if a simulation should only be used for ratesetting if it is in an environment that permits rapid and frequent recalibration of the model and adjustment of the rates based on it.

9. SUMMARY AND CONCLUSION

PA Consulting Group developed a set of assumptions for a probabilistic cost simulation model. The role of the model would be to characterize the uncertainty in PGE's annual net variable power cost. There are many factors that influence net variable power cost, some of which are related to yet subtly different from others. To properly identify all those factors, and model their variability, would be an immense effort; furthermore, information about many of them is not easily available. PA produced a "data issues report" that described the data that would be desirable for such a model; the availability or unavailability of some data; and potential substitutes or proxy data as well as weaknesses in some of those substitutes.

PA concluded that a cost simulation model had to be flexible and easily modified to allow easy substitution of different submodels for uncertain inputs and resource dispatch. PA specified an architecture for such a "sandbox" model that relies on the @Risk add-in to run a set of spreadsheets in a Monte Carlo fashion. A central "coordinator" manages variable names to allow different component spreadsheets to be "plugged" in or out.

We proceeded to develop a prototype of the simulation model. In principle the "base case" of such a prototype, with all random variables set to nominal or expected levels, should produce answers identical to a reference model (in this case a specific Monet run). That did not happen here, partly because the prototype involved simpler dispatch logic for some resources and partly because of the unfinished nature of prototypes.

Even if the base case doesn't line up exactly with the reference model, a cost simulation model can still provide useful information about the distribution of costs. The base case values depend on specific input levels and a good match between specific numerical results of different models can be difficult to achieve. If the inputs are inaccurate, the specific numerical outputs – the locational rather than shape parameters of the distribution – will be undependable. A simulation model can confirm one's intuition about the cost impacts of the relationships among inputs, as well as the approximate magnitude of that impact – e.g., the fact that the expected cost exceeded the "base case" cost by approximately 18% of the standard deviation in costs.

A cost simulation can provide valuable qualitative information about the distribution of net variable power costs. The shape of the distribution of outputs depends on the shapes of the distributions of the inputs and the relationships between the inputs and outputs, that is, the mathematical properties of the model. In other words, distributional shape data encapsulates information about the assumed relationships between inputs and outputs, and those relationships should look the same even if the inputs themselves are inaccurate.

Under the assumptions of the prototype model we conclude that the distribution of net variable power costs is positively skewed (the mean is larger than the median) and leptokurtic (exhibits "fat tails", that is, somewhat elevated chances of extreme values). It is both more skewed and more leptokurtic than a parametric distribution often used to model costs, the lognormal distribution. On the other hand, the mean of the distribution does not seem to depart far from the base case cost. That means that it is not possible to "risk-adjust" the cost distribution (for instance to set a revenue requirement) just by moving the mean to account for correlation of inputs. The precision afforded by a descriptive model such as this is not fine enough to permit one to estimate a "risk adder" but we can say that there is significant variability in the costs.

PA

The approach to cost simulation that PA has prototyped promises to help in the understanding of the way costs vary with uncertain inputs such as hydro conditions and market prices. It is particularly valuable because of its simplicity and flexibility. PA is willing to help PGE implement such an approach or to talk about ways to incorporate it into the Monet architecture.

APPENDIX A: COMPONENTS OF PROTOTYPE COST SIMULATION MODEL

This appendix briefly lists the components of the prototype cost simulation, Monet (base case) data used, other parameters, inputs (from other components) and outputs.

A.1 TEMPERATURE SIMULATION

A.1.1 Base Case data used

- Expected (normal) temperatures

A.1.2 Other parameters

- Description of randomness in temperature distribution

A.1.3 Inputs from other components

- None

A.1.4 Outputs

- Daily temperature and expected temperature

A.2 LOAD SIMULATION

A.2.1 Base Case data used

- Base case daily loads

A.2.2 Other parameters

- Description of randomness in load distribution
- Hourly load scaling factors

A.2.3 Inputs from other components

- Daily temperature

A.2.4 Outputs

- Hourly PGE load

A.3 GAS PRICE SIMULATION

A.3.1 Base Case data used

- Initial forward curves

A.3.2 Other parameters

- Parameters of price models

A.3.3 Inputs from other components

- None

A.3.4 Outputs

- Daily gas forward curve
- Daily gas spot price

A.4 HYDRO SIMULATION

A.4.1 Base Case data used

- None

A.4.2 Other parameters

- Historical distribution of hydro conditions

A.4.3 Inputs from other components

- None

A.4.4 Outputs

- Monthly hydro energy relative to average
- Monthly hydro capacity relative to average

A.5 MID-C POWER PRICE SIMULATION

A.5.1 Base Case data used

- Initial forward curves

A.5.2 Other parameters

- Parameters of price model

A.5.3 Inputs from other components

- Daily gas forward curve
- Daily gas prices
- Daily peak subperiod loads
- Hydro conditions

A.5.4 Outputs

- Daily on/offpeak forward power curve
- Daily on/offpeak spot power price

A.6 COST TO SERVE LOAD

A.6.1 Base Case data used

- None

A.6.2 Other parameters

- None

A.6.3 Inputs from other components

- Hourly loads
- Mid-C power prices

A.6.4 Outputs

- Cost to serve load from market (net variable power costs = cost to serve load from market minus value of production from other resources, plus costs of other resources)

A.7 PGE HYDRO SIMULATION

A.7.1 Base Case data used

- Base case energy
- Monthly, daily, hourly allocation factors
- VOM costs

A.7.2 Other parameters

- None

A.7.3 Inputs from other components

- Hydro energy relative to base case
- Mid-C spot power prices

A.7.4 Outputs

- PGE hydro plants' production in MWh
- Dollar value and cost of production (VOM) from PGE hydro plants

A.8 MID-C HYDRO SIMULATION

A.8.1 Base Case data used

- Base case energy
- VOM costs

- DLL code to optimize Mid-C dispatch
- Parameters of Mid-C optimization DLL routine

A.8.2 Other parameters

- None

A.8.3 Inputs from other components

- Hydro energy relative to base case
- Mid-C spot power prices
- MWh outputs of other PGE plants (for spinning reserve requirement)

A.8.4 Outputs

- Mid-C hydro plants' production in MWh
- Dollar value and cost of production (VOM) from Mid-C hydro plants

A.9 COLSTRIP SIMULATION

A.9.1 Base Case data used

- Monthly capacity, heat rate, maintenance schedule and forced outage rate by unit
- PGE ownership share
- Monthly coal prices
- VOM costs

A.9.2 Other parameters

- None

A.9.3 Inputs from other components

- Mid-C spot power prices

A.9.4 Outputs

- Colstrip production in MWh
- Dollar value and cost of production (fuel + VOM) from Colstrip plant

A.10 BOARDMAN SIMULATION

A.10.1 Base Case data used

- Monthly capacity and heat rate by state (min load / full load)
- Monthly maintenance schedule and forced outage rate

- PGE ownership share
- Monthly coal prices
- VOM costs

A.10.2 Other parameters

- None

A.10.3 Inputs from other components

- Mid-C spot power prices

A.10.4 Outputs

- Boardman production in MWh
- Dollar value and cost of production (fuel + VOM) from Boardman plant

A.11 BEAVER SIMULATION

A.11.1 Base Case data used

- List of operating states and allowable transitions
- Monthly capacity and heat rate by state
- VOM costs by state
- DLL code to optimize dispatch by dynamic programming

A.11.2 Other parameters

- None

A.11.3 Inputs from other components

- Spot gas prices
- Mid-C spot power prices

A.11.4 Outputs

- Beaver production in MWh
- Dollar value and cost of production (fuel + VOM) from Beaver plant

A.12 COYOTE SIMULATION

A.12.1 Base Case data used

- Simplified list of operating states and allowable transitions
- Monthly capacity and heat rate by state

- VOM costs by state
- DLL code to optimize dispatch by dynamic programming

A.12.2 Other parameters

- None

A.12.3 Inputs from other components

- Spot gas prices
- Mid-C spot power prices

A.12.4 Outputs

- Coyote production in MWh
- Dollar value and cost of production (fuel + VOM) from Coyote plant

A.13 FORWARD POWER CONTRACTING SIMULATION

A.13.1 Base Case data used

- None

A.13.2 Other parameters

- Description of purchase strategy

A.13.3 Inputs from other components

- Expected load, expected production from all resources (used to compute expected purchase requirement)
- Mid-C forward power prices

A.13.4 Outputs

- Daily forward purchases by tenor in MWh
- Dollar value and MTM of forward portfolio

A.14 SPOT MARKET SIMULATION

There is no spot market component in the design of the cost simulation as described in section 4. All energy produced or delivered is valued at the simulated spot price, that is, "marked to market". To the extent that simulated loads are greater than the generation simulated from all PGE's resources, power is implicitly bought on the spot market and priced at the simulated Mid-C spot power price.

PGE
Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204

July 18, 2006

Parties to Docket UE 165:

During the UE 165 proceeding, Portland General Electric Company (PGE) and Oregon Public Utility Commission Staff (OPUC Staff) entered into a Stipulation. Although the Commission rejected the Stipulation in Order No. 05-1261, PGE decided to fulfill the requirements of Section 12, under which "PGE agrees to obtain appropriate consultation services for the purpose of evaluating the statistical distribution of net power costs, at a cost of up to $100,000."

Based on responses to a Request for Proposals (RFP), PGE selected the PA Consulting Group (PA). Although PA's bid price was approximately 50 percent greater than the $100,000 target, we felt that PA was better qualified than the other bidders. PA has now completed its work on the statistical distribution of PGE's net variable power costs and issued a final report, which is attached.

The report includes the results of a Monte Carlo study of PGE's net variable power costs (see Page 7-39). However, there are several reasons why these results would not be an appropriate basis for setting rates or designing risk sharing mechanisms. The report itself includes the following reasons:

- "Uncertainty in the estimate of standard deviation would make it very difficult to use the numerical results of this prototype for ratemaking or to determine a 'risk adder' ...... a simulation should only be used for ratesetting if it is in an environment that permits rapid and frequent recalibration of the model and adjustment of the rates based on it." (See Page 8-45.)

- There are still problems with PA's modeling, in part because of the "unfinished nature of prototypes." (See Page 9-46.) Base case results are reasonable on an overall basis, but not on a resource by resource basis. (See table on Page 7-38.) PA addressed problems pointed out by PGE in a preliminary draft, but did not have sufficient time and budget to resolve remaining modeling issues.

- "The precision afforded by a descriptive model such as this is not fine enough to permit one to estimate a 'risk adder' but we can say that there is significant variability in the costs." (See Page 9-46.)

Portland General Electric

Docket UE 165
Page Two

Other reasons why the results are informative, but would not be an appropriate basis for setting rates or designing risk sharing mechanisms are:

- PA did not consider the off-setting revenue effects of load variations, which likely increases the dispersion of results in the Monte Carlo study. Although it is unclear what approach to including revenue effects would be most appropriate, the implicit assumption of no effect is not realistic.

- PA used data for hydro output, gas prices, loads, and electric prices from the past several years, but did not even begin to address the fact that the distributions of these key variables are changing significantly over time with changing regional load-resource balance, climate changes, world, regional, and local politics, etc. This is arguably the most significant limitation of the PA study.

PA did excellent work in beginning to model the distribution of power costs, demonstrating that PGE's net variable power costs are likely to vary widely. However, this is a very complex topic which does not lend itself to a simple "plug and play" result. At the end of the study, substantial problems remain. First, producing an accurate distribution of net variable power costs, simply based on the historical data available, would require considerably more work – inclusion of revenue effects related to load variations, better consistency with MONET on a resource by resource basis, etc. Second, PA did not even begin to incorporate the fact that the relevant parameter distributions are shifting over relatively short periods of time. Therefore, PGE does not believe that the PA study results provide an appropriate basis for setting rates or designing sharing mechanisms such as PCAs.

Sincerely,

Patrick G. Hager
Manager, Regulatory Affairs

g:\ratecase\opuc\dockets\ue-165_hydrotariff\stipulation\pa study\coverletterpareport.doc

II. Power Supply Objectives

Q. What are PGE's power supply objectives?

A. PGE's overall power supply objective is to meet our customers' power and reliability needs at a reasonable cost. PGE meets this objective by:

- Managing generation dispatch, power & fuels procurement, power operations, and risk management as an integrated business (Power Supply Operations).
- Managing Power Supply Operations to reduce net variable power costs given our portfolio of resources.
- Capturing the economic value of the assets within our resource portfolio by exercising our ability to make real-time changes in their operations.

Q. How does PGE meet customer supply requirements?

A. PGE meets the power resource requirements of its customers by using a portfolio management concept. In its simplest terms, PGE's power supply portfolio management involves a continual, integrated process of choosing and executing on resource opportunities in an attempt to achieve the highest value—with the least amount of risk. Like its counterpart in investment management, a power supply portfolio has assets (generation, purchased power, fuels, etc.) and component risks such as market price, credit default, unit outage, etc.

The portfolio management concept allows PGE to manage overall risk by considering the dynamic impacts of resource decisions on PGE's power supply portfolio. For example, in periods of high correlation between natural gas and power you can use natural gas to limit some of your downside risk of a price increase in power needed to serve retail customers by not purchasing the power but instead purchasing gas.

Q. What risks does PGE's "portfolio" of resources face?

A. Portfolio risk can be simply defined as the chance that changes in one or more of a variety of factors may alter the value of a particular commitment. For example, the value of a single short position commitment of 25 MW in the market is subject to risk as market price changes. For entities without an obligation to serve load, this risk can be eliminated by not buying. However, PGE must buy power to meet its obligation to serve retail customers. Therefore, PGE faces an inherent portfolio risk due to the requirement that we serve all customer loads and the hourly variability in those loads. PGE's power supply portfolio includes many other component risks that the Power Supply Operations group manages. Each of these risks can affect PGE's ability to meet its customers' power needs physically and at the established retail rates for PGE's customers. These include:

Price Risk - Potential fluctuations in prices of the underlying energy commodity.

Credit Risk - Potential adverse occurrence of a counterparty's ability to pay its obligations.

Counterparty Performance Risk - Potential adverse occurrence of a counterparty's ability to operationally perform on an agreement or obligation, such as an agreement to deliver power.

Volumetric Risk - The risk that commodity volumes will vary from expected volumes and result in a potential loss or gain due to changing commodity market prices. For example, a generating unit sells projected electric generation production forward and at the time of delivery a unit cannot deliver. This results in a loss if the price to purchase electricity to cover the sales is higher than the electricity sale price.

Basis Risk - The risk that the value of a futures contract (or an over-the-counter hedge) will not move in line with that of the underlying commodity exposure. Other forms of basis risk include product basis, arising from mismatches in type or quality of hedge and underlying product (e.g., power with natural gas); and time or calendar basis (e.g., hedging an exposure to physical product in December with a January forward contract). Basis differentials are generally due to differences in geography, quality, delivery, time, and options valuations.

Q. How does PGE manage these portfolio risks?

A. PGE manages these risks by first organizing them into portfolios or "books" by risk type. By this we mean the grouping of buys and sells for a particular commodity into appropriate time periods when the value, cost, or the variability of both is expected to occur. For example, all power transactions -- whether they are a purchase or a sale -- are aggregated into a specific book. Then, within that book, volumes and costs are further separated by such characteristics as delivery point, counterparty, etc. This breakdown allows PGE to evaluate the magnitude of the risks from a long (more than required) or short (less than required) position for any specific book, or component thereof, in the portfolio. Currently PGE maintains books for electricity, natural gas, fuel oil, coal, SO2 credits, transmission, and natural gas transportation.

Q. Please continue.

A. PGE relies on access to multiple physical and financial energy markets through firm transmission and transportation rights, railway contracts, electronic trading bulletin boards and organized financial commodity exchanges to more efficiently hedge its exposure to market price volatility and supply reliability. For example, PGE maintains access to the BPA transmission system that allow PGE to specify various delivery/receipt points as needed on a non-firm basis. These rights prevent PGE from being overly exposed to the potential price shocks and disruption of service of one delivery/receipt point and enable PGE to shift its buying patterns when it is economic to do so.

Q. Are there limits to the exposure that PGE takes in each of risk books?

A. Yes. Primary control of market risk is established through limits approved by senior management and the board of directors. These limits are used to require communication by and among both PGE management and PGE Power Operations personnel so that risks are known, communicated and appropriately evaluated in light of PGE's business and risk management objectives and strategies. These limits and sub-limits are applied on a daily basis based on the close-of-business positions and are expressed as a combination of: (a) a maximum Net Open Position, (b) a maximum Maturity/Gap Position, (c) a maximum Value at Risk (VaR), and (d) other metrics required by the Risk Management Committee. Any instances when actual results are in excess of corresponding limits require notification to the Vice President of Risk Management, the Chief Financial Officer and the President.

Q. Has one of these limits ever been exceeded?

A. Yes. Until recently PGE had not experienced a situation where risk limits were exceeded. However, on February 24, 2003 the natural gas and power markets experienced a six standard deviation move in power prices, combined with a thirteen standard deviation move in the western natural gas market. From Friday to Monday, the March natural gas contract jumped from \$6.80 per million British Thermal Units (MMBTU) to \$11.90/MMBTU on Access trading overnight. This was an unprecedented increase in NYMEX natural gas prices driven by cold weather in the Mid-West and concerns over current natural gas storage levels. In addition, the outlook for hydro conditions in the Pacific Northwest remained poor. As a result, power prices for the months of March 2003 through June 2003, increased by approximately \$10/MWh to \$15/MWh, while calendar years 2004 and 2005 increased \$5/MWh and \$2/MWh, respectively. As a further result, PGE at that time had an exposure to risks that exceeded its established limits. PGE could have brought the risks back within established limits by buying power or gas at these prices.

PGE's Power Operations management team met and decided to hold our gas and power positions, meaning we did not purchase forward additional gas or electricity on that day. The basis of this decision was our view that gas and power prices had exceeded their underlying economic fundamentals. As a result, when prices moderated back to previous levels, the temporary spike had little impact on PGE's power costs.

Q. How are the risk limits enforced?

A. PGE's Risk Management group enforces the limits on the Power Supply Operations group The Risk Management's group's responsibilities include:

- oversight of the overall wholesale power operations risks and risk management practices to ensure that they are consistent with Company policy and strategy.
- oversight of the development, approval and administration of policies, methodologies, and practices for measuring, monitoring and managing the risk exposures of the Company.
- establishment of counterparty credit limits.
- coordination of review and execution of all counterparty documents with PGE's Legal Department, including negotiating directly with counterparties to ensure credit risk is mitigated through contractual arrangements.

Q. What is the reporting structure for the Risk Management Group?

A. The Risk Management group reports directly to the Chief Financial Officer (CFO) and the Risk Management Committee (RMC), not Power Supply Operations. This functional separation provides the Risk Management group with the necessary independence to objectively evaluate the activities of the Power Supply Operations group.

Q. What are the RMC's responsbilities?

A. The RMC is responsible for the oversight of commodity position and price risk, foreign currency risk, and credit risk related to power supply activities. The RMC consists of officers or senior professionals with responsibility for risk management, finance and accounting, legal, rates and regulatory affairs, power operations, and generation operations. In addition, the RMC approves trading and credit policies and procedures, establishes risk limits subject to corporate approval, and monitors compliance and risk exposure on a regular basis through reports and meetings.

Two of the reports that the Risk Management group produce to monitor activity against established limits are the daily position and power reports. These reports are generated after we have stopped buying and selling each day, at approximately 2:00pm. The report provides employees and managers with a comprehensive understanding of how the Company is positioned compared to various markets and exposures.

Q. What does Power Supply Operations do with these reports?

A. Each morning upon receiving the Daily Position Report and prior to the trading day, PGE Power Supply Operations personnel review the reported power and gas positions, review and discuss observed changes in owned and market generation, and review early market price direction indications and other pertinent information. In addition, two other position meetings occur during the week:

- One to discuss the up-coming month of delivery (the prompt month), and to review credit, load forecast and contracts activity.
- One to review market fundamentals and evaluate our short-and mid-term position.

Portland General Electric Company
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Pamela Grace Lesh
Vice President
Regulatory & Federal Affairs

September 13, 2002

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

Attn: Vikie Bailey-Goggins
Administrator, Regulatory Operations Division

Re: Advice No. 02-8/UE-137

Portland General Electric Company (PGE) hereby withdraws Advice No. 02-8. This filing proposed to implement a power cost adjustment mechanism (PCA) for 2003. The Commission suspended the filing and opened Docket UE-137. PGE requests that the Commission close Docket UE-137.

There are several reasons for this action. First, our customers do not want a PCA for 2003. While Staff supports a PCA for 2003, Staff proposes a deadband so large that it would leave PGE with no earnings on its generation and energy supply functions before customers begin to share in negative power cost variations. Similarly, it is highly unlikely customers would see benefit from positive variations.

Second, Staff and our customers are unwilling to include variations in energy revenues in a PCA. These variations are included in the 2002 PCA. PGE believes that a PCA is fundamentally unworkable without including some type of load/revenue adjustment. Net variable power costs are a function of both the costs to acquire and generate power and the loads that PGE actually serves. Our customers determine our loads. Variations in load determine whether PGE is a seller or a buyer in short term markets and the market price determines whether the variations in load are positive or negative. Power costs alone are only a part of the equation.

PGE testified in UE-137 that we should collectively decide in advance how the risks and consequences of severe changes in net variable power costs should be shared between PGE and our customers. We still believe that. However, we do not believe that a decision reasonably acceptable to all parties is likely in UE-137. Our customers cannot accept PGE's proposal. PGE cannot accept Staff's proposal. PGE therefore believes that no PCA is preferable.

This leaves PGE and our customers in a familiar position. Our customers determine our loads. PGE manages collectively the overall variations in customer load from that forecasted. We have not agreed in advance how to allocate the costs and risks of large variations. Therefore, PGE will rely on traditional regulatory methods such as deferred accounting and additional rate cases when the variations have a significant financial impact on PGE.

We believe that traditional regulation may work for 2003. We do not now expect significant volatility in power prices. The markets appear to have settled down, at least for the short term. We do not expect significant variation in loads. Further, we continue to use the Resource Valuation process annually to set power costs for the coming year. This increases predictability in loads and costs because it is calculated near in time to the forecast year.

Our recently filed Resource Plan and our Least Cost Planning process should be used to determine best how to supply energy to each or our customer classes. Those processes should determine the risks to be incurred for each power supply portfolio for each customer class and how those risks should be allocated. We look forward to working with the Commission, Staff and customers on these important projects.

Sincerely,

Pamela G. Lesh

c: UE-137 Service List

Decision No. C03-0670

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 02S-315EG

RE: THE INVESTIGATION AND SUSPENSION OF TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO ADVICE LETTER NO. 1373 – ELECTRIC, ADVICE LETTER NO. 593 – GAS, AND ADVICE LETTER NO. 80 - STEAM.

ORDER APPROVING SETTLEMENT WITH MODIFICATIONS

Mailed Date: June 26, 2003
Adopted Date: May 29, 2003

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amount of $12.78 per MWh; the Company's fuel clause (first the IAC and then the ECA) shall recover Energy Costs in excess of $12.78 per MWh; and the Company shall withdraw its proposed Base Energy Credit.

- The Company agrees to file by June 1, 2007 to reduce base rates to eliminate the amortizations for the Pawnee 2 Pre-engineering costs and the Metro Ash Disposal Site option.

Electric Commodity Adjustment & Trading

Key aspects of the electric commodity adjustment (ECA) and trading issues are:

- 100% pass-through of CPUC fuel and purchased energy expense during 2003. Change existing rates using 2003 forecast beginning July 1, 2003. This would increase electric rates by $93.1 million above the amount being collected through the Interim Adjustment Clause that became effective January 1, 2003.
- Implementation of a new ECA based on the Company's formula on January 1, 2004. The formula will use as a test year the 12-month period ending August 31, 2003. The new ECA will remain in effect through calendar year 2006.
- The costs recovered through the ECA will be bounded as follows: The first $15 million above and $15 million below the ECA base is shared 50% to retail customers and 50% to shareholders. The next $15 million above and $15 million below is shared 75% to retail customers and 25% to shareholders. Beyond $30 million, 100% of the CPUC jurisdictional cost increases or decreases will be passed on to retail customers.

- The Company will file an application on April 1, 2006 addressing the regulatory treatment of fuel and purchased energy expenses beyond December 31, 2006.
- The 100% pass-through IAC that is in effect in 2003 and the incentive ECA rate that is in effect in each year generally will be modified annually, but shall be subject to more frequent modification within certain constraints.
- Within certain limits, the Company will be permitted to sell gas which was purchased for electric system operation, but which is not needed for certain months or certain days.
- Margin sharing shall be calculated separately for each of the Generation Book margins and Proprietary Book margins.[13] Within each book, the CPUC jurisdictional Gross Margins shall be aggregated annually. If these aggregated margins from either book are negative, the negative margin shall not be passed on to retail customers.

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13 *See* discussion of Trading, *infra* at Section XIII, in which further definition is supplied concerning the Company's Generation and Proprietary Book trading operations.

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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 appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the positions various parties take with respect to PGE's net variable power cost (NVPC) forecast for 2007 and to show the results had any one of PGE's Variance Tariff, or CUB or ICNU's power cost adjustment (PCA) mechanisms been in place from 2002 through 2005. We also address the alternatives presented for handling load variations with a PCA mechanism.

Q. How does your testimony relate to the Resource Valuation Mechanism (RVM) settlement signed by Staff, CUB and ICNU?

A. PGE, OPUC Staff, ICNU, and CUB have entered into a stipulation regarding PGE's NVPC forecast for the 2007 RVM for January 1, 2007 until rates from the general rate case are effective. As stated above, the purpose of this testimony is to discuss the parties' NVPC regulatory frameworks and their proposed adjustments to PGE's NVPC forecast in the general rate case.

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

A. The Commission should:

- Not adopt the proposed adjustments for extrinsic value due to their one-sided nature.
- Calculate forced outage rates for PGE's coal 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 seven sections.

Section II presents the results of a simple application of PGE's, Staff's and CUB's proposed power cost adjustment mechanisms to the years 2002 through 2005. Although too short a period to demonstrate the full range of outcomes likely under the various proposals, it is instructive.

Section III addresses Staff's proposal that the Commission order us to develop and implement expected value NVPC forecasting. In this section, we rebut various parties' suggestions that, because PGE uses stochastic analysis in selecting the least cost mix of resources with which to serve customers, the Commission should use stochastic analysis techniques to choose a point forecast of NVPC for purposes of setting rates on a test year basis.

In Section IV we respond to various adjustments parties propose related to PGE's forecasted NVPC for 2007, including:

- Extrinsic value of certain PGE owned and contractual resources
- Forced outage rates for Boardman and Colstrip
- Ancillary Services
- Coal Losses

- Addition of Port Westward in the NVPC forecast

Section V addresses CUB's concern that PGE has not made an adequate showing of Port Westward's prudence because our filing did not include a status report on all of the items in the acknowledged 2002 IRP Action Plan.

In Section VI, we address an issue regarding our Beaver 8 resource that has arisen because it is unlikely that the Commission will issue an order in Docket UM 1066 prior to the effective date of rates set in this proceeding.

In Section VII, we address an issue regarding the development of rate making margin and effective tax rate for purposes of the AR 499 tax true-up.

II. Application of Proposed Mechanisms

Q. What do you cover in this Section of your testimony?

A. In this Section, we apply PGE's Variance Tariff, and the PCA mechanisms proposed by Staff and CUB to a sample period. We also discuss the implications of various proposals for the treatment of load variations.

A. Application of Variance Tariff and Other PCA proposals to Sample Period

Q. Did you apply the Variance Tariff and the PCA mechanisms proposed by Staff and CUB to some sample years?

A. Yes.

Q. Which years did you use?

A. We used 2002 through 2005.

Q. Why have you only presented these years?

A. For these years, we have a Commission-approved forecasted NVPC, set in our RVM proceedings. For years prior to 2002, we did not have this except for the 1995 and 1996 test years.

Q. Do you have a caveat about these years?

A. Yes. During each of these years, hydro power production in the NW was less than the historic average. Because of the significance of hydro production to PGE's actual NVPC, the resulting actual NVPC outcomes are higher in three of the four years than the forecasted NVPC.

Q. Why didn't you use the data that you used for the chart you presented in PGE Exhibit 400 which shows the historic variance between forecasted and actual NVPC since 1993?

A. Because of the regulatory framework in place in the 1990s, we did not have Commission-approved forecasted NVPC for most of these years; we have them only for the UE 88 test period – 1995 and 1996. We had to construct forecasted NVPC for many of the years in this chart, using simplifying assumptions. It is illustrative only, as ICNU's testimony recognizes (ICNU/103, Falkenberg/30).

Q. Have you performed an analysis of Staff's and CUB's proposed mechanisms?

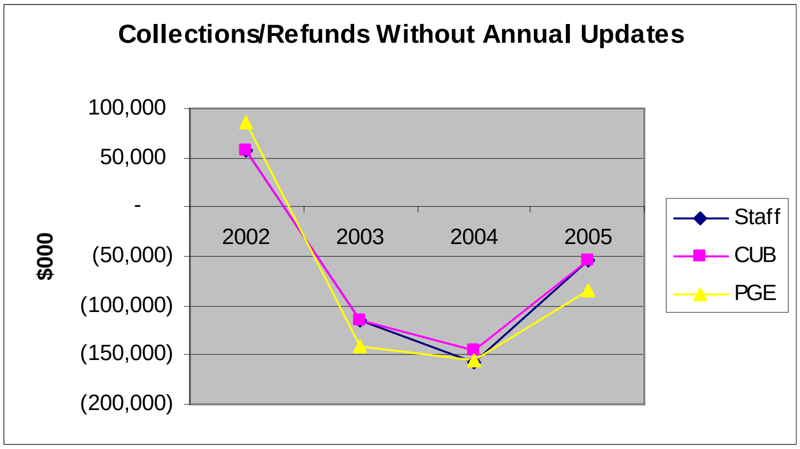
A. Yes. We calculated the variance amounts by comparing actual and forecast unit net variable power costs for the period. We adjusted actual and forecast net variable power costs consistent with PGE's proposed Schedule 126. For PGE's proposed Variance Tariff (VT), we multiplied the difference between actual and forecast unit net variable power costs by actual load to determine the variance. For Staff's proposed PCA mechanism, we multiplied the unit cost difference by forecast loads[1] consistent with Staff's suggested approach. Finally, since CUB did not provide a detailed approach to calculating variance amounts, we assume that the CUB mechanism would also use Staff's proposed methodology.[2] We then applied the PGE, Staff and CUB proposed sharing mechanisms to the variance amounts, including any earnings test, to determine the results.

Q. What does your application of the mechanisms proposed by Staff, CUB, and PGE to the years 2002 through 2005 generally show?

[1] See Staff/800, Galbraith/15.
[2] On CUB/200, Jenks-Brown/20-21 CUB seems to indicate a preference for a broad (or as they say "encompassing") mechanism rather than a more narrowly defined mechanism such as a hydro-only PCA. Both PGE's and Staff's proposed variance formulas are broadly based with the distinction that unit cost differences in PGE's proposal are multiplied by actual load while in Staff's proposed mechanism they are multiplied by forecast load. For simplicity, we analyzed the PCA results of CUB's proposed sharing bands and earnings test based on Staff's proposed variance formula.

A. We looked at this two ways: with and without an Annual Update. For the latter, we assumed that the NVPC forecast established in Docket No. UE 115 remained in place for all four years. Under this assumption, the figure below illustrates the results of the three mechanisms over the sample period.

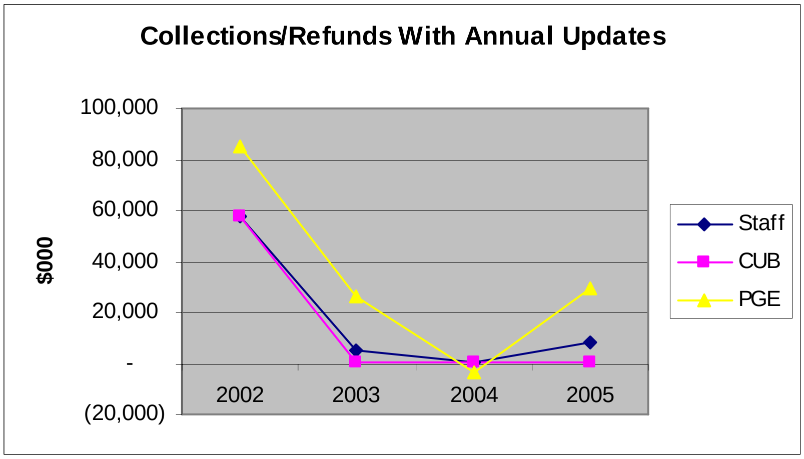
Figure 1



For the four-year period, the Staff and CUB proposals would have resulted in net refunds of $270 million and $258 million respectively, whereas the PGE proposal would have resulted in higher net refunds of $298 million. Savings retained by shareholders under the Staff and CUB proposals would have been $159 million and $171 million respectively, whereas the PGE proposal would have allocated only $58 million to shareholders.

If we assume annual updates, namely PGE's RVM filings for 2003-2005, the results change significantly, as shown in the figure below.

Figure 2



For the four-year period, the Staff and CUB proposals would have resulted in net collections by PGE of $72 million and $57 million respectively, whereas the PGE proposal would have resulted in higher net collections of $137 million. Under the Staff and CUB proposals, shareholders would have absorbed $97 million and $112 million respectively, whereas the PGE proposal would have resulted in shareholders absorbing $15 million.

These general results demonstrate that annual updates make a significant difference, given the magnitude of year-to-year changes in gas and electric prices and other factors which influence power costs.

Q. What were the specific results of CUB's proposed PCA?

A. In the case of annual updates, for the years 2003 through 2005 CUB's proposed PCA would have resulted in outcomes within CUB's proposed deadband ($38 million for actuals greater than forecasted, $19 million for actuals less than forecasted). This occurs in spite of the fact that PGE's regulated ROE for two of the three years was significantly below PGE's authorized level of 10.5%. In the case of no annual updates, CUB's proposed PCA would have resulted in substantial refunds in the years 2003-2005, as actual power costs decreased from the levels set in UE 115.

Q. What were the specific results of Staff's proposed PCA?

A. In the case of annual updates, Staff's proposed mechanism would have triggered in three of the four years. However, the amounts deferred for recovery in 2002 and 2004 are small relative to the variance in power costs that occurred during the year. In the case of no annual updates, Staff's proposed PCA would have resulted in substantial refunds in the years 2003-2005, as actual power costs decreased from the levels set in UE 115. The 2004 refund is larger under Staff's proposal than under CUB's, given Staff's smaller deadband.

Q. What were the specific results of PGE's Variance Tariff?

A. PGE's VT mechanism would apply in all years because PGE does not propose a deadband. In the case of annual updates, PGE's proposed mechanism would have brought PGE's regulated ROE closer to the authorized level than either Staff's or CUB's proposed mechanism. In the case of no annual updates, PGE's mechanism would still trigger in all years, given that PGE does not propose a deadband. No deadband results in larger refunds to customers over the 2003-2005 period than do the CUB and Staff proposals.

Q. Doesn't this mean that PGE's proposed VT would effectively guarantee that PGE would earn its authorized ROE?

A. No. PGE can still face substantial shortfalls in earnings. In 2005, for example, even with PGE's VT, our earned ROE would have been approximately 200 basis points below the authorized earnings level because of other risks that we bear as well as the sharing that occurs under our formula.

Q. Do you have any comments about the proposed earnings test of CUB and Staff?

A. Yes. Both Staff and CUB suggest an earnings test first described in the Commission's UE 165 Order, which involves an additional earnings deadband of 100 basis points below or above the authorized ROE. In the backcast scenarios (with annual updates), the earnings test was only triggered in one scenario (2002 under Staff's proposed mechanism). Given the substantial power cost variance deadbands supported by both parties, an additional earnings test deadband seems unlikely to act as a constraint in most circumstances. This is because PGE's power cost volatility is large relative to any discretionary operations and maintenance costs savings that we might obtain or outcomes of other uncertainties.

Q. Did Staff consider SB 408 in their PCA proposal?

A. No (Galbraith Deposition, PGE Exhibit 1801, page 13). This is inconsistent with the Commission's determination in Order No. 06-400 in which the Commission states (on page 9) "In response, we will consider the tax effects when evaluating issues in other dockets, such as power cost adjustment mechanisms."

Q. Did Staff consider effects of their proposal on PGE's cost of capital?

A. While stating there were discussions between the witnesses, Staff admitted they did not know what effect their proposal would have on PGE's cost of capital (Galbraith Deposition, PGE Exhibit 1801, page 17). They also admit that neither the existence, nor type, of PCA that a utility has was a factor in determining Staff's discounted cash flow (DCF) sample (Morgan Deposition, PGE Exhibit 1901, pages 1-2).

Q. Have you prepared an Exhibit containing the detailed results of your application of the various parties' mechanisms to the 2002-2005 period?

A. Yes. PGE Exhibit 1902 provides these details.

B. Treatment of Load Variations

Q. Is the basic formulation of PGE's proposed Variance Tariff similar to the power cost adjustment proposed by Staff?

A. Yes. Both determine the difference between unit (per kWh) actual NVPC and forecast NVPC. Multiplying the per kWh difference by load determines the power cost variance to which any deadband or sharing applies.

The difference between the two proposals is the load. PGE recommends use of the actual load experienced while Staff recommends use of the normalized loads used in the NVPC forecast. For most years, the difference is generally small but we have experienced significant deviations such as in 2002.

Q. What is the basis for PGE's recommended treatment?

A. As discussed in PGE/400 pages 35 & 36, our proposal aligns actual NVPC with revenues. In other words, total actual NVPC equals the amount collected through rates (the forecast unit NVPC times load) plus the power cost variance.

Q. Have you developed a set of examples that demonstrate this fact?

A. Yes. Page 1 of Exhibit 1903 demonstrates how PGE's mechanism would operate under a series of hypothetical events. For purposes of simplicity, we have assumed a utility with a load of 20,000,000 MWh and a unit NVPC of $40/MWh. This yields a total NVPC of $800,000,000. The example shows the effect on PCA Revenue (without any deadband or sharing) and revenue from the NVPC portion of energy rates of the following events:

- Actual loads are +5% and -5% of forecast
- Actual NVPC are +10% and -10% of forecast
- The four combinations of the above cases.

We show the results of the example with the price of market power both above forecast unit NVPC at $60 per MWh and below forecast unit NVPC at $30 per MWh. In each case, the change in total NVPC is equal to the sum of the PCA Revenue plus the change in revenue from the NVPC portion of energy rates.

Q. Why does Staff recommend using the normalized loads used to set rates?

A. Staff indicates that this recommendation "maintains the traditional allocation of load risk" and that "[t]his formula accounts for the offsetting impacts of load variation on fixed cost recovery and NVPC" (Staff/800, Galbraith/15-16).

Q. Will Staff's recommendation achieve this goal?

A. Under very specific circumstances it might but, in general, no.

Q. Have you prepared a set of examples that demonstrates this fact?

A. Yes. Page 2 of Exhibit 1903 provides this demonstration. It is similar to page 1 but uses Staff's formulation.

As demonstrated in this example, if PGE meets a load increase by power purchased or generated at a cost greater than the unit NVPC, the overall change in revenue (PCA plus NVPC in rates) is less than the overall change in NVPC. This could be considered consistent with Staff's concept that the non-NVPC portion of the revenue increase due to increased load will help cover any such shortfall.

However, if there is a load decrease, the decrease in revenue exceeds the decrease in NVPC, thus exacerbating the revenue lost from the non-NVPC portion of the rate.

The opposite occurs when the cost of incremental power is less than the forecast unit NVPC. In the load increase case, PGE would receive increased PCA revenue in addition to the additional non-NVPC revenue. When there are changes in both loads and underlying NVPC, the difference between the overall NVPC and the change in NVPC related revenues can be substantial and counterintuitive.

Q. Does ICNU propose a different formulation?

A. Yes, ICNU's testimony proposes that we calculate the power cost variance as the difference between actual and forecast total NVPC adjusted for load variations at the forecast market prices used to establish rates.

Q. Do you support ICNU's proposal?

A. No. ICNU's proposal does not align actual NVPC with NVPC-related revenues. Page 3 of Exhibit 1903 illustrates this point, showing that there are significant differences when load varies from forecast.

Q. What is your recommendation regarding how the Variance Tariff, or any other PCA mechanism, should adjust for the effects of load differences on the comparison of forecasted NVPC to actual NVPC?

A. PGE continues to recommend that the Commission adopt our proposal to remove these load differences from the reconciliation by multiplying the load change by the change in unit power costs. It provides a reasonable result under a wide range of circumstances. It also leaves with the utility the risk that non-NVPC revenues will not cover non-NVPC costs.

III. Expected Value Power Costs

Q. Does Staff recommend that the Commission require PGE to begin developing test year NVPC forecasts on an "expected value" basis?

A. Yes. See Staff/800, Galbraith/19; Staff/200, Wordley/5-6. Indirectly, ICNU also encourages this, concluding that it "would be inequitable for the Commission to allow resource selections to be made on the basis of extrinsic value modeling, but not to reflect the extrinsic value benefits in setting rates" (ICNU/103, Falkenberg/10-11).

Q. Do you agree with Staff's recommendation?

A. No.

Q. Has PGE done additional work on the issue of expected value power cost modeling?

A. Yes, through a consulting firm called "PA Consulting Group." Pages 16-18 of PGE Exhibit 1800 provide details on this modeling and PGE Exhibit 1803 is a copy of the resulting report.

Q. Please summarize what the PA Consulting Group did.

A. The introduction of the report states that:

> PA Consulting Group has been retained by Portland General Electric to define a "cost simulation model." The basic simulation model would simulate the net variable power cost over a period of time subject to certain assumptions about loads, market prices, hedges in place and hydro conditions. That model could then be run over a large sample of potential realizations of those assumptions in order to estimate the statistical properties of the distribution of net variable power costs. (Report Introduction, Page 1-1).

Q. What are the important conclusions of this report for purposes of the Commission's consideration of Staff's recommendation?

A. As stated in Section II of PGE Exhibit 1800, this report draws several important conclusions, including:

- The distribution of uncertainty data is critical to estimating expected value. If one intends to use the model to produce a "once and for all" number, what the authors call a "prescriptive" use, then one must invest considerable effort in estimating the underlying values. On the other hand, if one intends to use the model to understand the likely size of the difference between forecasted and actual, and make frequent adjustments based on that outcome, what the authors call "descriptive" use, then one can invest less in the underlying values. The "Black-Scholes" formula used to value stock options is a "descriptive" use because brokers value the options every day, observing the reaction to the previous day's trading, and adjust both the model's parameters and their portfolios. Thus, the exposure to pricing errors is controllable (pages 3-14 to 3-15).
- A 1000-iteration run of the cost simulation model PA produced (a "descriptive model") showed a significantly skewed distribution, with a standard deviation of $55 million and a higher peak and fatter tails than one would expect in a normal distribution. PA indicated its belief that the standard deviation is likely understated. In addition, the difference between the base case value and the "expected value" was a positive $10 million. This suggests, were one to attempt to use the descriptive model for ratemaking, that the test year NVPC forecast should be $10 million higher than MONET indicates.

Q. Are there limitations to the PA report?

A. Yes. The report notes on pages 9-46 that "[t]he precision afforded by a descriptive model such as this is not fine enough to permit one to estimate a 'risk adder' but we can say that there is significant variability in the costs." PGE sent a cover letter along with distribution of the PA report to parties to the UE 165 docket. This letter noted a number of issues related to the PA report. PGE Exhibit 1804 is a copy of the cover letter, dated July 18.

Q. Does the report suggest, however, that the reductions (ranging from $12.4 million to $14.5 million) to the test year NVPC forecast for the "extrinsic value" of a few of PGE's resources represent an incomplete picture of the cost of PGE's resource portfolio?

A. Yes. The report found that, when considering most factors which can cause power cost variations, rather than simply the extrinsic value of some resources, it appears that, on average, a MONET projection understates expected power costs.

Q. Did Staff perform any stochastic modeling of their own?

A. No. Staff admits they performed no such analysis in this case, or any other case (Galbraith Deposition, PGE Exhibit 1801, page 9). Staff further admits they do not have the tools necessary for such an analysis (Wordley Deposition, PGE Exhibit 1904, page 4).

Q. Are there factors that Staff failed to consider in proposing an adjustment for extrinsic value?

A. Yes. Staff suggests stochastic modeling should consider the "uncertainty and interaction associated with system load, electricity and natural gas market prices, hydroelectric generation and thermal unit availability…" (Staff/200, Wordley/2). Yet, Staff's analysis consisted of looking solely at a subset of PGE's thermal resources and capacity contracts.

Q. Did Staff consider the extrinsic value customers receive from their ability to take as much or as little electricity from PGE at any time?

A. No. Staff recognizes there is a value associated with customers' optionality (Wordley Deposition, PGE Exhibit 1904, page 5). Staff however failed to consider this.

Q. Is Staff's extrinsic value adjustment an appropriate substitute for stochastic modeling?

A. No. As mentioned above Staff failed to consider all of the necessary factors. Staff admits they have "no idea" if their adjustment matches with the value one would get with stochastic modeling (Wordley Deposition, PGE Exhibit 1904, pages 6-7).

Q. If the MONET projections systematically overstated power costs, what would you expect a review of the difference between test year forecasted NVPC and actual NVPC to show?

A. We would expect such a review to show that PGE's actual NVPC are systematically less than forecasted NVPC. However, Table 1 below shows that this is not the case. In three out of the four years from 2002-2005, actual NVPC were greater than forecasted (and the one year when actuals were less occurred when actual loads were substantially below forecast). The data in Table 1 are consistent with those used to construct the graph on page 34 of PGE Exhibit 400.

Table 1
Power Cost Variations ($Million)

Year	Forecast	Actual	Difference
2002	810	760	(50)
2003	453	613	160
2004	450	538	88
2005	491	539	48

Q. Do the parties suggest that the Commission should order PGE to engage in test year NVPC forecasting on a stochastic, expected value basis because that is the type of analysis PGE performs in the IRP process?

A. Yes. Staff states that "[i]t is inconsistent to use sophisticated risk modeling when making IRP decisions, only to revert to deterministic point-estimate modeling when making ratemaking decisions" (Staff/200, Wordley/8). However, Staff makes no suggestions on how to model power costs stochastically. Staff does not know the time period for modeling (Wordley Deposition, Pages 5-7), and does not possess the statistical modeling tools to use in ratemaking (Wordley Deposition, Page 14, Line 2). Staff is not aware of any Commission that has used statistical modeling to set test year power costs (Wordley Deposition, PGE Exhibit 1904, page 7).

Q. Why does PGE use stochastic modeling in its IRP analysis, but not in its modeling for rate setting purposes?

A. First, we want to be clear that stochastic modeling is just one of the analytical approaches we use during the IRP process. IRP analysis concerns the content of a resource portfolio, asking the question which resources, when added to the ones already existing, produce the best outcomes under conditions of uncertainty for certain key variables? Based on these results, PGE makes selections among types of resources. At this selection point, the goal is the lowest possible cost of service for future on-demand retail electricity customers. The resulting numbers are not the baseline for any allocation of the risk of the uncertain outcomes.

As explained in Exhibit 1800, the test year NVPC forecast is the basis of allocating uncertain outcomes between PGE and customers. Ideally, it does so evenly. The PA report would indicate it does not, but the error is against PGE, not customers. Using stochastic modeling for prescriptive purposes would require prohibitive precision in all of the parameters; using it descriptively and indicatively in the IRP process does not. We disagree with Staff that our application is in any way inconsistent.

Q. If PGE does not perform stochastic modeling for rate setting purposes, doesn't this imply that customers don't receive the value of PGE's resources?

A. No. Customers receive the intrinsic value of these resources. As the Commission resets our cost of service prices, customers receive the benefit of changed expectations about plant operations when market conditions change. For example, in the UE 115 rate case, we expected substantial output from the Beaver plant due to market conditions. As that forward expectation changed with subsequent RVMs, customers received the benefit that came from ramping down Beaver's expected operation. Customers also receive value through the hourly shaping factors that PGE applies to forward curve-based power prices within MONET. We discuss this at length in Section IV, Part A.

Updates of the test year NVPC forecast, through the Annual Update Tariff we have proposed, ensure that customers receive this intrinsic value. Adopting the

Variance Tariff, in addition, provides customers with any residual "extrinsic value" PGE is able to achieve in a given year, subject to the 90-10 sharing formula that encourages PGE to seek opportunities to realize this value.

Q. Are there other reasons why stochastic modeling is appropriate for resource acquisition decisions, but not for rate setting?

A. Yes. In considering a resource acquisition, we can stress test our uncertainty modeling to see the extent to which a resource choice is dependent upon the uncertainty modeling assumptions being made. This option doesn't exist in forecasting power costs for rate setting purposes because resources are given and only one expected value power cost outcome will be used as the basis for setting rates. Again, this relates to the fundamental decision(s) that are made in resource acquisition, i.e., whether a particular resource will be acquired or not. In contrast, rate setting is ultimately about setting a point forecast, given a set of existing resources. Confidence that can be derived through modeling uncertainty in resource acquisition decisions is not easily transferred to the rate setting process.

IV. 2007 NVPC Forecast Issues

Q. To what issues raised by the parties do you respond in this Section?

A. We respond to adjustments parties propose that reduce our 2007 test year NVPC forecast for the "extrinsic value" of certain of PGE's resources (part A), a new methodology for calculating an assumed forced outage rate for PGE's coal generating plants (part B), and assumed revenues from the wholesale sale of ancillary services (part C). We indicate our agreement with Staff's removal of the coal losses we assumed in connection with the rail transportation of coal to Boardman (part D). We also address CUB's concern regarding how we propose to model test year NVPC for two different periods: before our Port Westward plant enters service and after it does so (part E). We offer concluding comments regarding these proposed 2007 test year NVPC forecast adjustments and the related issue of our Variance Tariff (part F).

A. Extrinsic Value

Q. What conclusions does the discussion in this Part of your testimony support?

A. In this Part of our testimony, we provide analysis leading to the following conclusions:

- Other parties' proposals inappropriately focus only on factors which might reduce actual power costs, ignoring factors which might increase actual power costs. This leads to parties' conclusions that the MONET forecast should be reduced, whereas a more comprehensive analysis leads to the opposite conclusion.

- Staff bases its proposal largely on the inappropriate use of one single figure from an analysis used to rank capacity bids in an IRP process. The analysis was neither intended nor appropriate for ratemaking, as demonstrated by empirical evidence to date.
- ICNU bases its proposal on an incorrect application of its theoretical framework, thereby greatly overstating the results. The MONET forecast already credits customers with most of the benefits suggested by a corrected version of ICNU's approach.
- CUB and ICNU fail to recognize that the purpose of capacity resources is to meet extreme customer load requirements of short duration. These parties' focus on "making money from dispatch benefits" ignores the role of these resources in providing reliable "on-demand" service to customers.

Q. What is the basis of the reductions to the NVPC forecast that the parties proposed for extrinsic value?

A. The parties believe that certain of the owned and contractual resources that PGE has in our power supply portfolio to provide on-demand retail electric service have "value" that PGE can realize, year after year on an ongoing basis and, thus, that ought to reduce our NVPC forecast. These resources (depending on the proposing party) are: Port Westward, Beaver, Coyote, two capacity contracts, one low-heat rate gas tolling agreement, and the customer-owned distributed stand-by generation for which PGE has limited contractual operation rights. The theory is that, under some gas and power market conditions, PGE can run these resources more than the NVPC forecast indicated they would run and earn the margin between the cost of gas and the price of power. Our NVPC forecast does not reflect this because it models only a point electric power market and gas market price per hour along with, we note, a point forecast of retail load and all other resource operations for that hour.

Based on applying this theory to a set of the resources indicated above, Staff ultimately recommends a 2007 NVPC forecast decrease of $12.4 million (Staff/200, Wordley/1). Using a slightly different set of resources, ICNU recommends a decrease of $14.5 million (ICNU/103, Falkenberbg/3, Table 1). CUB does not specify a dollar figure, but states that "PGE's Monet model fails to recognize the extrinsic value of capacity resources, such as gas-fired generation plants and capacity contracts" (CUB/100, Jenks-Brown/10). CUB states further that the Commission could either reduce fixed costs associated with certain resources in the revenue requirement or "adopt an adjustment to account for the extrinsic value of PGE's capacity resources" (CUB/100, Jenks-Brown/12).

Q. Do you agree that the Commission ought to reduce the test year forecast of PGE's NVPC on the assumption that PGE can operate these specific resources more frequently than the model indicates?

A. No, for several reasons. First, the parties ignore that PGE serves retail customers and that retail customers' demand for power will rise significantly above forecast on occasion, particularly during extreme weather events. The parties also ignore that any one or more of PGE's resources can experience difficulties at any time necessitating a substitution of one resource for the other. It is for these contingencies that PGE, along with every other retail electric utility, has capacity resources in addition to energy resources. In the "test year" course of events – essentially what we model to produce a forecast of NVPC – capacity resources may not "run." They are available for events that we anticipate but cannot precisely forecast. The parties' adjustments "sell" this capacity to the market. If it is sold to the market, it is not available to serve retail load.

Second, even apart from the issue of serving retail customers, these recommendations are all one-sided. They only consider factors that might, in some years, result in actual net variable power costs lower than those forecasted by MONET. PGE's power cost projection for the 2007 test year will be based on a November 2006 MONET forecast, using baseline values for many parameters and forward gas and electric curves at the time we make the run. We know that actual plant operations, as well as purchases and sales, will differ from the MONET forecast in many ways. Some of these differences will tend to decrease power costs; some will tend to increase power costs. Although the ability to produce more power from PGE's resources than shown in MONET might be expected to decrease power costs, there are many ways in which actual experience will tend to increase power costs over those in the MONET forecast.

Probably the most important factor that will, on average, tend to increase power costs over the MONET projection is the inverse relationship between power prices and hydro production. Low hydro production puts upward pressure on power prices, whereas high hydro production puts downward pressure on these prices. This means that the cost to replace shortfalls in low hydro years is greater than the value of the "extra" power production in high hydro years, or that the inverse relationship between power prices and hydro production will tend to, on average, increase power costs over the MONET projection. This effect was described in PGE's UE 165 testimony, which we include as Exhibit 1802.

Q. Do any of the parties appear to recognize the one-sided nature of this proposed adjustment?

A. Yes. The ICNU testimony explains that there is no extrinsic value for coal or hydro generation because these resources offer "no expected savings" (ICNU/103, Falkenberg/8). These low-variable cost resources expose PGE to significant risk that the assumed cost of service will be less than the actual cost of service. High-variable cost resources expose customers to the flip-side: that the actual cost of service will be less than the assumed cost of service. The parties propose an adjustment only to further lower customers' risk, but do not propose an adjustment for the other risks that PGE bears.

Less directly, Staff does indicate agreement that many of the variables affecting NVPC correlate with each other. Staff explains:

> It is likely that some level of correlation exists, for example, between loads and power prices, between hydro conditions and power prices, and between gas prices and power prices. By not capturing these correlations between variables, Monet is not accurately portraying the real world of power operations. (Staff/200, Wordley/5).

We agree that one could estimate extrinsic value only, if at all, by evaluating the complete picture of all of PGE's resources and the relationships that they have to market variables (gas and electricity prices) as well as the interaction of those variables with PGE loads. As we explained in Section III, however, such an attempt would be fraught with difficulty and unlikely to produce a "better" test year NVPC forecast than we presently use, in the sense that it would be closer to the following period's actual NVPC.

Q. Can you provide a simple example that demonstrates how evaluating the extrinsic value of a thermal resource in isolation of other effects can produce misleading results?

A. Yes. We start with the following assumptions about a forecast for the test period used to set rates:

Average Retail Tariff Rate	7.85 cents/kwh
Expected Beaver January Output	0
Beaver Capacity	500 MW
Beaver Heat Rate	9.500 mmbtu/MWh
Expected January Sumas Gas Price	$9.80/mmbtu
Expected January Market Clearing HR	7.500 mmbtu/MWh

Q. Are these assumptions realistic?

A. Yes. PGE's average retail rate is between 7.5 and 8.0 cents/kWh. Our initial filing in this docket included parameters very similar to those assumed in the example.

Q. Please continue with your example.

A. Assume that in January the region experiences a 48-hour storm which results in the following actual parameters during this period:

Length of Storm	48 hours
Energy Demand Above Forecast	24,000 MWh (500 aMW * 48 hours)
Avg Sumas Spot Price	$12.00/mmbtu
Avg Mid-C Spot Price	$144.00/MWh
Avg. Market Clearing HR	12.000 mmbtu/MWh

Because Beaver is more efficient that the average market clearing heat rate (9.5 vs 12.0 market clearing rate), PGE operates Beaver at capacity (500 MW) during the storm and meets all of the additional demand placed on the system due to the storm.

Q. Isn't this an example of an event which would create the extrinsic value for Beaver that Staff and other parties discussed in their testimony?

A. Yes. The forecast used to set rates assumed that Beaver would produce no output and circumstances actually resulted in the plant producing energy that has value. This additional value (in $000) can be calculated as follows:[3]

Value of Beaver Generation	$3,456	(500 MW*48 hours*$144.00/MWh)
Cost of Beaver Generation	$2,736	(500 MW*48hours*9.50mmbtu/MW*12.00/mmbtu)
Beaver Margin	$720	Extrinsic Value

Thus, Beaver produces margins of about $0.72 million that were not reflected in rates.

Q. Doesn't this mean that the storm has resulted in PGE earning $0.72 million more than presumed in rates?

A. No. The margin represents the amount by which the operation of Beaver reduced PGE's costs relative to a circumstance in which PGE would have met the additional load through market purchases. Alternatively stated, it is the additional margins that would have been earned if PGE sold the output to customers at market based rates rather than cost of service tariff rates. The impact of the storm on PGE's financial results can be calculated as follows:

Additional Retail Revenue	$1,884 (500 MW * 48 hours * 7.85 cents/kWh)
Additional Fuel Costs	$2,736 (From Above)
PGE Gross Margin	$(852) Loss

Thus, when viewed through an inappropriately narrow lens, the plants have produced value. However, a more complete view results in a different conclusion. Stochastic modeling of PGE's power costs must take this broad perspective or it runs the risk of developing erroneous conclusions.

Q. Have you prepared an Exhibit that includes your example calculations?

A. Yes. These calculations are in PGE Exhibit 1905.

[3] For simplicity, we ignore gas transportation, variable O&M, and Beaver's ramping constraints. In reality, all of these costs would reduce extrinsic value.

Q. The example focused on Beaver's ability to reduce costs. Is this the only purpose of capacity resources?

A. No. The most important purpose of capacity resources is to meet the obligation to serve customer loads under all conditions. We discuss the role of capacity resources in more detail at the end of this part of our testimony.

Q. Have you evaluated the specific extrinsic value calculations Staff and ICNU make?

A. Yes.

Q. Please summarize Staff's calculations.

A. Staff recommends extrinsic value adjustments for five of PGE's resources: Super-Peak Capacity Contract; Morgan-Stanley Tolling Agreement; Beaver; Coyote; Dispatchable Stand-By Generators. Staff discusses three alternatives, which would result in the following overall extrinsic value adjustments:

- Alternative 1: $13.991 million
- Alternative 2: $12.353 million
- Alternative 3: $5.759 million (Staff/200, Wordley/12).

All three alternatives include the same recommendations for the Super-Peak Contract, the Morgan-Stanley Tolling Agreement, and PGE's dispatchable stand-by generators. Specifically, Staff recommends the following extrinsic value adjustments for these resources:

- Super-Peak Contract: $1.304 million
- Morgan-Stanley Tolling Agreement: $0.125 million
- Dispatchable Stand-By Generators: $0.188 million

Q. What is the basis of Staff's adjustment to the Super-Peak Contract?

A. Staff made its calculation on information included in PGE's confidential response to Staff Data Request No. 040 in LC 33, PGE's most recent Integrated Resource Planning (IRP) docket. That response included the modeling results PGE used to evaluate capacity bids in our 2003 Request for Proposals (RFP). This modeling included a per MWh measure of extrinsic value, which Staff then used to calculate its annual adjustment in this docket. Specifically, the adjustment of approximately $1.3 million is the product of the number of hours in a contract season (December, January, and February), the size of the contract (100 MW), and the per MWh measure of extrinsic value.

Q. Do you agree with Staff's analytical approach?

A. No. Staff's approach has two significant shortcomings. First, PGE used the RFP modeling to rank competing bids, not to make revenue requirement forecasts. The RFP analysis focused on relative, rather than absolute, scores. Staff makes the error of using the Super-Peak extrinsic value score as a forecast. It was not a forecast. Second, Staff does not use more recent information. In its direct testimony, ICNU states that the Super-Peak contract has only dispatched 12 hours (during its first winter contract season) (ICNU/103, Falkenberg/19). Using this information, Staff's recommendation is only consistent with per-MWh margins greater than $1000 during the hours of contract dispatch (100 MW x 12 hours x $1080/MWh = $1.3 million). Margins were never close to $1000 per MWh during the first winter season, nor are they expected to be so during January, November, and December of the 2007 test year. In addition, we do not know of any forecast for any year that suggests $1,000/MWh margins.

Q. What is the basis of Staff's adjustments for the Morgan-Stanley Tolling Agreement and PGE's Dispatchable Stand-By Generators?

A. Staff calculates these adjustments by multiplying the size of the resource, the number of hours it is available but not shown as dispatching in a particular MONET test year NVPC forecast (and an assumed capacity factor for the Stand-By Generators), and per MWh extrinsic or option value figures.

Q. Do you agree with this approach?

A. No. The per MWh extrinsic value figures are roughly extrapolated from the RFP modeling results for the Cold-Snap, Super-Peak, and two other short-listed capacity contracts. Thus, these figures suffer from the problems we discussed in the context of the Super-Peak Contract above, as well as the fact that they are the product of an additional extrapolation step. In addition, the Dispatchable Stand-By Generators are generally limited by contract to 400 hours per year, which is less than the availability assumed in Staff's analysis.

Q. What is the basis of Staff's adjustments for Beaver and Coyote?

A. Staff's preferred approach (Alternative II) starts with the differences between the hours these plants ran in 2001 and the hours they are dispatched by MONET in the 2007 test year. The plants ran more in 2001 than they are forecasted to run in 2007. Specifically, the differences between Staff's 2001 historical figures and the 2007 figures forecasted by the MONET run submitted in PGE's March filing are 378

MWa for Beaver and 117 MWa for Coyote. Staff provides no basis for using 2001, in the middle of the West Coast energy crisis, as its base for its calculation.

Staff multiplies these hours (converted to MWh) by a per MWh extrinsic value figure that Staff derived by averaging the RFP extrinsic value measures for the Cold-Snap and Super-Peak Contracts, $3/MWh. Staff adds $1/MWh for Coyote, and subtracts $1/MWh for Beaver, because Coyote's heat rate is lower. The resulting adjustments are then $4.1 million and $6.6 million for Coyote and Beaver respectively.

Q. Is it analytically sound to extrapolate the RFP extrinsic value figure for application to Coyote and Beaver?

A. No. Staff uses a "base" per MWh figure taken from the RFP evaluation process for the Super-Peak Contract. For purposes of ranking RFP capacity bids, PGE evaluated the Super-Peak Contract <u>over the winter period</u> in which it is in effect. This type of analysis would yield a significantly lower result if it were applied to a contract in effect for the entire year, because the contract has more value per hour in the winter period than the average value per hour across an entire year. Staff uses a "proxy base" from the winter only Super-Peak Contract, even though Coyote and Beaver are available across the entire year.

Q. Does Staff offer alternative approaches?

A. Yes; however, these are only based on different assumptions regarding the hours Beaver and Coyote supposedly are available to produce "extrinsic value." Under Alternative I, Staff bases the adjustments on the hours these plants are available, but not dispatched, by MONET in the 2007 test year – 445 MWa for Beaver and 131

MWa for Coyote. Alternative I is incomplete, in that it does not consider planned maintenance outages. Under Alternative III, Staff bases the adjustments on the differences between the average hours these plants ran during the last 10 years and the hours they are dispatched by MONET in the 2007 test year – 136 MWa for Beaver and 50 MWa for Coyote.

These alternative assumptions change Staff's results significantly. Alternative I results in adjustments of $4.6 million and $7.8 million for Coyote and Beaver, respectively, whereas under Alternative III these adjustments are $1.8 million and $2.4 million. Total adjustments for Coyote and Beaver under the three alternatives are then:

- Alternative I: $12.4 million
- Alternative II: $10.7 million
- Alternative III: $ 4.2 million

Q. Please summarize ICNU's extrinsic value calculations.

A. ICNU calculates extrinsic value for only the Beaver, Coyote, and Port Westward plants, and for the Super-Peak and Cold-Snap Contracts. These adjustments sum to approximately $14.5 million, $11.4 million for the PGE-owned plants and $3.1 million for the contracts.

For the plants, ICNU witness Falkenberg explains that he "used historical spreads for Mid-Columbia market electric and gas prices based on Intercontinental Exchange (ICE) day-ahead prices for the period June 2002 to June 2006. Spreads are computed for each resource using its specific heat rate. From these data, we developed monthly adjusted spread distributions taking the mean value of the spread from the gas and power prices used in Monet. We then computed the probability (and savings) from off-loading units as well as from making additional sales" (ICNU/103, Falkenberg/8).

Q. Did ICNU correctly apply this approach?

A. No. The ICNU witness incorrectly applied the analytical framework he constructed and failed to include planned and forced outages.

Q. Have you performed an analysis to correctly implement ICNU's approach?

A. Yes. PGE Exhibit 1906-C includes this analysis. A comparison of the results listed on Table 1 of ICNU/103 and the corrected results of the same approach are as follows (figures are $):

Table 2
Summary of ICNU Table 1 Extrinsic Value

	HLH	LLH	Total
Coyote	2,234,872	1,754,327	3,989,199
Beaver 1-7	1,447,624	72,118	1,519,742
Port W	2,956,964	2,932,330	5,889,295
Total	6,639,460	4,758,775	11,398,236

Table 3
Summary of Corrected Extrinsic Value

	HLH	LLH	Total
Coyote	606,230	494,483	1,100,713
Beaver 1-7	311,197	10,813	322,010
Port W	1,008,325	488,341	1,483,906
Total	1,925,753	993,636	2,906,629

ICNU claims $11.4 million as an extrinsic value that should reduce PGE's test year forecast of NVPC. However, correct application of ICNU's methodology leads to a much smaller number: $2.9 million.

Q. Has PGE prepared an exhibit that explains ICNU's incorrect application of its basic framework?

A. Yes. PGE Exhibit 1907 provides two examples that demonstrate the errors in ICNU's application of its approach – one for cases in which spreads based on monthly forward curves are positive, and one for cases in which these spreads are negative.

Q. What is the major conceptual problem with ICNU's approach?

A. ICNU implicitly assumes that MONET simply uses monthly on- and off-peak spreads from the forward curves, i.e., that MONET does not incorporate variation in spreads across the hours of a given monthly on- or off-peak period. This is incorrect.

Q. How does MONET reflect hourly price variability?

A. The MONET modeling uses historical hourly price information. To develop hourly prices, we begin with typical price profiles for winter, summer, and off-season, for weekdays, Saturdays, and Sundays. Because we model on-peak prices as independent from off-peak prices in a given month, we review price transitions from on-peak to off-peak hours to make sure they are appropriate. We also examine hourly prices for a typical weekday, Saturday, and Sunday for each month in the forecast period to make sure the prices are consistent between hours (e.g., Sunday prices lower than Saturday prices on-peak, for example).

Q. What is one way to identify this conceptual problem in ICNU's approach?

A. One way to identify the problem is to compare the overall dispatch value of Coyote, Beaver, and Port Westward credited to customers in the MONET run ICNU uses in its analysis and the overall margins implied by ICNU's approach, after the corrections discussed above. The former is available from the MONET hourly diagnostic report, and the latter is calculated in PGE Exhibit 1908-C. Variable gas transportation and O&M costs are both handled in such a way as to make the two figures comparable. PGE Exhibit 1908-C then compares the two results.

Q. What are the summary results from PGE Exhibit 1908-C?

A. Summary results (figures are $):

Table 4
Value of Coyote, Beaver, and PW Under ICNU Methodology

	Coyote	Beaver	PW	Total
Base Margins:	6,150,054	0	10,470,268	16,620,321
Extrinsic Value:	1,100,713	322,010	1,483,906	2,906,629
Total Value:	7,250,766	322,010	11,954,174	19,526,950

Table 5
Value of Coyote, Beaver, and PW in March MONET Run

	Coyote	Beaver	PW	Total
Value of Output:	65,816,608	0	92,330,450	158,147,058
Cost of Output:	59,700,135	0	79,733,219	139,433,354
Net Value:	6,116,473	0	12,597,231	18,713,703

The MONET run credits customers with $18.7 million for the test year (with Port Westward available from March through December) and ICNU's methodology implies credits to customers of $19.5 million. This suggests that MONET already credits customers with most of the "extrinsic value" calculated with ICNU's approach.

Q. Does MONET include constraints that ICNU's analysis does not which decrease the ability to dispatch or stop dispatching PGE's gas-fired plants?

A. Yes. MONET includes ramping constraints and minimum "up" times for these plants. This decreases MONET's ability to take advantage of a theoretical ability to turn these plants on or off hour-to-hour, and is more consistent with actual possibilities for plant operation. Thus, even the $0.8 million of additional value in ICNU's approach compared with MONET is subject to doubt because it reflects unrealistic, physically impossible, operational flexibility.

Q. What are some overall limits on the modeling results discussed above?

A. All of the results are based on particular data sets and modeling approaches. For example, ICNU bases its analysis on June 2002 to June 2006 ICE data and a MONET run using February 23, 2006 forward gas and electric curves. Changes in data sets, as well as changes in modeling approaches, lead to large changes in results.

Q. What is the basis for ICNU's Super-Peak and Cold-Snap Contract-related adjustments?

A. Rather than extrapolate from PGE's RFP analysis as Staff did, ICNU performed its own extrinsic value analyses of the Super-Peak and Cold-Snap Contracts. These analyses indicated no extrinsic value for either contract. Disregarding this, ICNU then relies on PGE's RFP evaluation figure to calculate a $1.4 million adjustment for the Super-Peak contract reasoning that, because PGE performed this analysis, our "decision to sign the Super Peak contract was largely based on consideration of extrinsic value" (ICNU/103, Falkenberg/10). Because PGE's RFP evaluation of the Cold-Snap Contract included an extrinsic value measure of zero, ICNU recommends that the Commission exclude the entire fixed cost of this capacity contract, approximately $1.7 million, because "absent consideration of extrinsic value, these contracts add nothing but a 'dead weight' cost, with no offsetting benefits for ratepayers" (ICNU/103, Falkenberg/19).

Q. Do you agree with these forecast adjustments?

A. No, for two reasons. First, ICNU selectively uses its own calculations. ICNU's own extrinsic value calculation for the Super-Peak Contract is zero, but the ICNU witness nonetheless recommends reducing test year NVPC by approximately $1.4 million. ICNU uses its own extrinsic value calculations for PGE's owned gas-fired resources, however.

Second, ICNU appears to suggest that a utility providing on-demand retail electric service does not require capacity resources. The Super-Peak and Cold-Snap contracts are part of PGE's Commission-acknowledged 2002 IRP Final Action Plan (Order No. 04-375). We selected these capacity resources through PGE's 2003 RFP process. These resources are necessary to meet extreme situations of short duration. PGE did not, and does not, expect them to dispatch frequently. PGE explained the purpose of capacity resources and of the Super-Peak and Cold-Snap Contracts in particular, in its responses to ICNU Data Request Nos. 125 and 126. The non-confidential portions of these responses are included as Exhibit 1909. ICNU implies that the Super-Peak and Cold-Snap Contracts are somehow "excess," or not needed, and therefore their fixed costs should not be included in customer rates. PGE's responses to ICNU Data Request Nos. 158-161 make clear that during the July 21-24, 2006, period, PGE did not have excess capacity resources. In particular, PGE's responses to ICNU Data Request Nos. 160-161 demonstrate that PGE has the appropriate quantity of summer capacity resources. These responses are included as

Exhibit 1910. PGE's capacity needs are approximately 450 MW greater in the winter than in the summer. The sizes of PGE's winter capacity resources, the Super-Peak and Cold-Snap Contracts, sum to 400 MW, and roughly fill the winter-summer capacity differential.

Q. Does CUB also appear to believe that a utility providing on-demand retail electric service may not have capacity resources?

A. Yes. CUB states that: "Only non-normalized events dispatch these capacity contracts. Non-normalized costs and benefits are the utility's to absorb." CUB also argues that the capacity resources only "generate sales revenue for the benefit of the Company." We disagree with this position for the same reasons we explained above. Moreover, CUB's statements imply that the Super-Peak and Cold-Snap Contracts dispatch frequently, to the benefit of shareholders. As mentioned above, the Cold-Snap Contract has never dispatched and the Super-Peak Contract has dispatched only 12 hours to date. Finally, CUB confuses revenues with margins. Any "gains" made by the contracts would be the difference between revenues and costs, not simply revenues.

B. Forced Outage Rates

Q. What summary conclusions do you reach in this Part of your testimony?

A. Our discussion in this Part of the testimony supports the following conclusions:

- PGE's overall plant performances compare favorably with national averages, as demonstrated by NERC effective availability factor (EAF) data. While the NERC data are useful for general comparisons, they are not appropriate for ratemaking.

- Other parties' recommendations, such as the exclusion of Colstrip's forced outage rate for a single year, are opportunistic and simply aimed at lowering the test year NVPC forecast.
- The Commission should consider all potential ramifications of any change in policy on the treatment of outages in ratemaking.

Q. Do PGE's plants perform at acceptable levels?

A. Yes. Several parties have suggested our plants perform at unacceptable levels. They show this through selective use of NERC data. A look at NERC's Equivalent Availability Factor (EAF) does not support parties' conclusions.

Q. What is the NERC EAF, and how do PGE's plants compare?

A. EAF is essentially the total hours a unit is available (less any deratings) divided by the total period hours. The EAF takes into consideration both forced and maintenance outages.

ICNU and Staff use NERC forced outage rates for comparison of PGE's coal units with a national average. A more reasonable comparison examines the EAF as there may be issues with reporting NERC data, as we discuss further below. Using the same NERC data and peer groups as ICNU and Staff, it is obvious that PGE's plants perform at reasonable levels. Table 6 below compares the NERC EAF data with actual plant performance. The comparison below demonstrates that while Staff and ICNU claim that PGE's plants show slightly higher forced outage rates, these are offset by lower planned maintenance outages.

Table 6
EAF Comparisons

Coal Plants 400-599MW	Four-Year Average	2004	2003	2002	2001
Boardman EAF	83.83%	70.98%	88.20%	84.83%	91.32%
NERC EAF	83.74%	84.89%	84.17%	83.12%	82.77%

Coal Plants 600-799MW	Four-Year Average	2004	2003	2002	2001
Colstrip EAF	84.14%	92.48%	83.33%	83.80%	76.95%
NERC EAF	84.16%	83.62%	85.74%	84.06%	83.20%

Q. Why is it inappropriate to compare NERC and PGE plant EAFs based on a single year?

A. For any individual year, the EAF of a single plant could reflect one-time events, such as a major upgrade that requires an extensive maintenance outage. Evaluating EAFs over a multiple-year period helps smooth such one-time events.

Q. What is the basis for the plant forced outage rates assumed in PGE's 2007 test year NVPC forecast?

A. The MONET forecast of test year NVPC assumes plant forced outages based on four-year rolling averages for each specific thermal plant. For the 2007 test year, this is the weighted average of outages during the years 2002, 2003, 2004, and 2005. The methodology uses a July 31, 1984, OPUC Staff Memorandum (Staff/102, Galbraith/1-21). It is relatively straightforward to implement, and parties have more than 20 years of experience working with it.

Q. Did PGE include the entire time that Boardman experienced a forced outage in 2005 in this average?

A. Yes, we did. As all are well aware, however, PGE has requested a deferral of the replacement power costs we incurred for a part of this time: the days from November

18 to December 31. We explained in Docket No. 1234 that we are willing either to include these outage days in the rolling four-year average or to have the Commission address them in the deferral docket (UM 1234 PGE/100 Lesh/6-7 l. 21-8). We are not seeking both.

Q. Does Staff have a recommendation for Colstrip's forced outage rate if test year NVPC forecasting continues to use the traditional four-year rolling average methodology?

A. Yes. Staff recommends that the calculation of Colstrip's four-year average not include data from 2002 because "Colstrip is impacted by particularly poor unit performance in 2002" and "this methodology inappropriately gives too much weight to this extreme outage event" (Staff/100, Galbraith/13).

Q. Do you agree with Staff's recommendation?

A. No. PGE has included Colstrip's 2002 performance in three prior test year forecasting proceedings: the 2004, 2005, and 2006 RVM dockets. Neither Staff, nor any other party, recommended this adjustment. Nothing about the 2002 data has changed and Staff offers no reason for its change in position.

Q. Have parties previously suggested such an adjustment for Pacificorp's portion of Colstrip?

A. We are unaware of any such recommendations. We have reviewed the Staff, ICNU, and CUB testimony presented in UE 179, as well as the stipulation, and find no such suggestion. Further, in ICNU's response to PGE Data Request No. 015, included as Exhibit 1911, they state: "ICNU did not make a specific recommendation regarding Colstrip's forced outage rate in UE 179."

Q. Do the parties suggest that the Commission depart from the methodology it has used for forecasting test year NVPC since 1984?

A. Yes, Staff and ICNU do. Staff suggests an alternative approach only for PGE's coal generating plants: Colstrip and Boardman. ICNU adds Coyote Springs to this list. All of PGE's remaining generating facilities would continue under the old methodology. Staff recommends that the Commission use North American Electric Reliability Council (NERC) "peer" group averages to forecast forced outage rates, with the peers based on plants of comparable size and fuel type (Staff/100, Galbraith/11-14). Staff explains that "the average annual performance of a peer group of units [will] be less volatile than the performance of an individual unit" (Staff/100, Galbraith/10). ICNU recommends use of these same data, but handled "stochastically" (ICNU/103, Falkenberg/2). ICNU's reasoning is that "[u]se of the four-year average has a possible unintended consequence of making utilities less sensitive to plant reliability, as it provides additional revenues when reliability is bad and reduces revenues when reliability is good" (ICNU/103, Falkenberg/2).

Q. Does Staff provide any demonstration that basing forecasted forced outage rates for Colstrip and Boardman on the NERC data will be less volatile than using the four-year average methodology?

A. No.

Q. Does ICNU provide any evidence in support of the "possible unintended consequence" of lowered utility concern about plant reliability?

A. No. Moreover, ICNU apparently does not realize that a forced outage lowers net income in the year it occurs, as the utility replaces the power at prevailing market prices. While inclusion of outages in test year assumptions for four years after occurrence may provide an opportunity to recover some losses, full cost recovery is far from certain. The utility also typically incurs higher O&M costs, working to repair whatever has caused the outage.

Q. Does ICNU offer any examples of utilities showing lower concern for plant reliability because their prices reflect, one way or another, historical forced outage rates they experience for their generating plants?

A. No.

Q. Do either Staff or ICNU make any demonstration that using NERC data, stochastically or not, will produce test year forced outage rate assumptions that are more accurate than the rolling four-year average methodology?

A. No. They provide no such demonstration either for 2007 or for any particular series of years.

Q. Is there a clear best way to select peer groups from within the NERC data?

A. No. There are many ways to parse the NERC data, not simply by size and fuel type.

Q. How do Staff and ICNU select peer groups?

A. They both use NERC data that is classified only by size of plant and fuel type, e.g., 600-799 MW and coal for Colstrip.

Q. Does NERC recommend using data in this way?

A. No. NERC itself offers a benchmarking service, and in its material criticizes the approach Staff and ICNU chose. PGE Exhibit 1912 is a copy of NERC material on its benchmarking service. It states that

> "many benchmarking programs have assumed that for fossil steam units, fuel type and size ranges are the proper selection criteria. We have

> found from our extensive benchmarking studies that fuel types and especially the arbitrary size ranges (100-199 MW, 200-299 MW, etc.) are relatively much less statistically significant than other design and operational characteristics such as criticality, duty cycle, vintage, pressurized/balanced draft, etc. Because each individual unit is unique, our process ensures that the optimal peer group is selected; balancing the need for similarity in design and operations with the need for a large enough sample size for statistical validity. Without this objective analysis to find the optimal peer select criteria any conclusions drawn from the comparisons could very well be invalid and misleading."

Ironically, Staff cites this document (Staff/100, Gaalbraith/18, footnote 5) but disregards NERC's advice in choosing peer groups.

Q. Are there other potential issues with the use of NERC data?

A. Yes. Utilities report to NERC voluntarily; nothing requires this reporting. Also, data reporting may not be consistent across all utilities. For example, one plant's forced outage may be another plant's maintenance outage.

Q. Did Staff recognize this potential issue?

A. Yes. Staff recognized this (Staff/100, Galbraith /11-12) and suggests adjusting NERC forced outage rates.

Q. Please explain.

A. PGE adjusts forced outages as reported by the individual generating plants to included forced maintenance outages. That is, the plant may report an outage as a maintenance outage if the plant was able to delay the outage for a short period of time. However this outage is properly classified as a forced outage, and reflected as such in our RVM filings.

Staff's solution to the forced/maintenance outage issue with NERC data is to apply an adjustment equal to the percentage difference between PGE's forced outage rate as reported by the plant and that used for RVM filings. This adjustment is 7.26

percent and 7.69 percent for Boardman and Colstrip respectively. The major problem with Staff's solution is the reliance on the untested assumption that other utilities have the same correlation between forced outages and forced maintenance outages as reported to NERC.

Q. Has Staff used NERC data in the past?

A. Yes. In the 1984 memo NERC data was incorporated only when there was insufficient plant data. Further, the analysis focused on vintage, in addition to capacity and fuel type.

Q. Do you agree with ICNU's assertion that the NERC data provide an "objective, verifiable means of estimating power costs?" (ICNU/103, Falkenberg/15).

A. No. As we noted above, reporting is voluntary and even Staff recognizes that reporting utilities may not do so using consistent definitions. While NERC data may be fine for general comparisons, it is not appropriate for ratemaking purposes.

Q. What adjustments to 2007 test year forecasted NVPC do Staff and ICNU propose based on this change in methodology?

A. Staff recommends reducing PGE's 2007 test year forecasted NVPC by $12.847 million. ICNU recommends a reduction of $7.175 million.

Q. Could you verify the calculations ICNU made to produce the suggested reduction to the 2007 test year NVPC forecast?

A. No. The capacities of Boardman and Colstrip shown in ICNU's analysis were incorrect, listed as 383 and 294.8 when actual capacities are 380.25 and 293.6 respectively for the 2007 test year. Also, we could not verify the NERC forced outage rates that ICNU listed for Coyote. Table 7 below shows the NERC values for all Combined Cycle plants – a copy of the NERC data is included as Exhibit 1913.

Table 7
NERC vs ICNU Forced Outage Comparison
Combined Cycle - all MW Sizes

	2003	2002	2001	2000	1999
ICNU	4.55%	3.38%	2.65%	2.51%	4.33%
NERC	4.55%	3.47%	3.27%	3.62%	5.20%

After correcting these errors, ICNU's adjustment falls $1.5 million from $7.175 million to $5.673 million.

Q. Are there other issues with ICNU's outage adjustments?

A. Yes. For their outboard adjustment ICNU used NERC EAF distribution data for both Boardman and Colstrip (ICNU/103, Falkenberg/14-17) .

Although ICNU's adjustment lowers PGE's cost recovery in the current situation, this would not be true under certain assumptions. In fact, ICNU's adjustment methodology indicates premium payments by customers to PGE when PGE's EAF exceeds the NERC average.

Further, ICNU's adjustment methodology could disincent plant upgrades. Any plant upgrade requiring the shutdown of the plant will lower the plant's EAF. This in turn leads to a penalty for the utility as the EAF may fall below a national average.

Q. Do you agree with Staff's and ICNU's recommended methodology change from the four-year rolling average to NERC data, the reasons offered, or the proposed reductions to the 2007 test year NVPC forecast?

A. No. The recommendation and proposed reductions appear opportunistic and the reasons are unsupported by anything other than opinion. Further, they fail to provide a compelling rationale for changing an approach the Commission has used for more than twenty years.

C. Ancillary Services

Q. Does Staff propose to reduce PGE's 2007 test year NVPC forecast for revenues it assumes PGE can earn by selling ancillary services?

A. Yes. PGE began selling these services to the California ISO in June 2005. Staff proposes to assume that, on an ongoing basis, PGE can earn $1.65 million in revenue for these services, calculating the annual amount by extrapolation from the amount PGE had earned through April 2006.

Q. Are there problems with Staff's adjustment?

A. Yes. As PGE noted in its response to Staff Data Request No. 307, "there is considerable risk around making a revenue projection for the test year." This is because we have limited experience to date and revenues have varied substantially from month to month, from less than $5,000 to more than $400,000. In addition, sales of ancillary services hinder the ability of PGE to optimally dispatch hydro resources, effectively shifting hydro production from peak to off-peak periods.

Q. Would Staff's proposal need adjustment to be consistent with more recent data?

A. Yes. Staff based its proposal on PGE's response to Staff Data Request No. 307, which included revenue data through April 2006. It did not include revenue data for more recent months, and it did not include associated costs, namely grid management charges imposed by the California ISO impose. Net sales revenues for the 12-month period ending July 2006 were $1.38 million.

Q. What do you conclude from the data?

A. During our limited experience these net revenues have varied considerably. The correct approach to handle this uncertainty would be through a comprehensive variance tariff, such as the one proposed by PGE in Exhibit 400.

D. Coal Losses

Q. Does Staff contest the increase to the test year NVPC forecast that PGE recommended based on coal losses in transit?

A. Yes. Staff recommends that the Commission not accept this forecast increase.

Q. Did PGE update its study with more recent data?

A. Yes.

Q. What were the results of the update?

A. More recent data indicate much lower coal losses.

Q. Given the updated results, does PGE agree with Staff's position?

A. Yes.

E. Reflecting Port Westward in NVPC Forecasts

Q. When does PGE currently expect that Port Westward will begin commercial service?

A. We expect the plant to come on-line on March 1, 2007.

Q. How do you propose that the Commission reflect Port Westward in PGE's cost of service rates given this on-line date?

A. We propose that, when Port Westward enters service, the Commission add Port Westward's fixed costs as determined in Docket No. UE 184 to the 2007 test year cost of service it will have already approved in Docket No. UE 180, and replace the

2007 test year NVPC forecast produced without Port Westward and included in the Docket No. UE 180 prices with the lower 2007 NVPC test year forecast produced with the plant shown available as of March 1, 2007. We will produce both forecasts in November 2006, per the RVM schedule. On November 2, 2006, PGE will make a filing that locks down all data inputs except forward price curves. This will be followed by a final RVM filing on November 9, 2006.

Q. What are CUB's concerns about the interface between the 2007 test year NVPC forecast used for Docket UE 180 prices and the 2007 test year NVPC used for Docket UE 184 and effective with Port Westward's commercial operation?

A. CUB expresses concern that the Docket No. UE 180 2007 test year NVPC forecast has a "phantom open position" for the months of March through December because it shows market purchases for that period rather than Port Westward operation (CUB/100 Jenks-Brown/7-10). Retail prices would not reflect the cost-of-service NVPC "benefit" of Port Westward until the plant begins commercial operation. CUB believes that this handling of the NVPC test year forecast might allow PGE to recover more than the forecasted NVPC, on an expected basis, or increase risk to customers.

Q. Will PGE's proposed method of handling Port Westward's effects on NVPC allow PGE to recover more than expected, forecasted NVPC?

A. No. Work papers 191-193 to PGE Exhibit 200 demonstrate that PGE should recover (on a forecast basis, not an actual basis) exactly our 2007 forecasted NVPC power costs expected over the entire 12-month test year. Our proposed method spreads the effects of the "phantom open position" over all twelve months of the test period, and "concentrates" the NVPC benefits of Port Westward over the ten-month March-December period when Port Westward is expected to be in operation. On a 12-month basis, the NVPC benefits of Port Westward exactly compensate for the "phantom open position." Risk does not change.

Q. Have you prepared a numerical example to demonstrate that PGE's structure neither allows PGE to recover more than the 2007 test year forecasted NVPC, on an expected basis, nor increases risk for customers?

A. Yes. PGE Exhibit 1914 contains such an example. This exhibit also includes a discussion of the results inherent in Work papers 191-193 of PGE Exhibit 200.

Q. Does this structure result in large differences between January-February rates and those in March-December?

A. No. In PGE's original filing in this docket, the January-February rates would be approximately 0.06 cents per kWh higher than March-December rates. (This is equal to the annualized Port Westward dispatch benefits, divided by loads at the customer meter, i.e., $11,798,000 / 19,601,562 MWh = $0.60/MWh, or 0.06 cents per kWh.) With respect to risk shifting between the January-February and March-December periods, a $1/MWh change in the electric forward curve would translate into a shift of approximately $230,000 in PGE's original filing, i.e., collections would increase by that amount during the January-February period, but decrease by that amount during the March-December period. (In the initial filing, Port Westward dispatches 158 MWa, or 1,384,080 MWh. The January-February "phantom open position" is then approximately one sixth of this, or 230,000 MWh. Then a $/MWh change results in a shift of $230,000 between periods.) PGE Exhibit

1914 discusses these potential shifts, which are very small in relation to overall net variable power costs of approximately $850 million.

Q. Do you support CUB's proposal (CUB/200 Jenks-Brown/9-10) to include Port Westward in the 2007 NVPC forecast that affects cost of service prices before Port Westward comes on line?

A. No. First, since Oregon law precludes including the cost of new system investments in rate base until these investments are "used and useful," the dispatch benefits of such investments should not affect prices either. Second, as a matter of regulatory policy, the Commission should not split the price effects of a new generating resource in this way. It sends the wrong price signal to customers and requires that PGE assume the additional risk of a forecasted on-line date with respect to NVPC.

Q. Does ICNU also criticize how PGE has included Port Westward in the 2007 NVPC forecast?

A. Yes. ICNU is concerned that PGE has determined the annual NVPC reduction benefit associated with Port Westward incorrectly because we computed the ratio of the 10-month dispatch benefit to the 10-month load times the 12-month load but the dispatch benefit is not proportional to load (ICNU/103, Falkenberg/21-22). ICNU believes that Port Westward dispatch benefits will generally be higher than their annual average during January and February and that PGE's methodology overlooks this.

Q. Is this criticism valid?

A. No. PGE computed the Port Westward adjustment for rates that would be in effect only during the 10-month period from March through December of 2007. January and February are not relevant.

Q. Does a concern exist, however, with PGE's methodology if the Commission does not approve the Annual Update Tariff or, by some other means, set cost of service prices based on a new NVPC forecast as of January 2008?

A. Yes. If rates were to be in effect beyond 2007, then power cost modeling would need to consider Port Westward's dispatch in all months.

Q. What would you recommend if this occurs?

A. We recommend that the Commission have us produce a new MONET run that includes Port Westward through the entire year, replacing the MONET run used for the 2007 test year NVPC forecast. This would pick up the January and February benefits directly.

Q. Would ICNU's suggested methodology also directly calculate the expected January and February Port Westward dispatch benefits?

A. No. ICNU recommends an outboard adjustment, which extrapolates Coyote results to Port Westward through a series of calculations. In addition, ICNU uses the results of a Docket No. UE 181 RVM run to criticize PGE's adjustment, which we prepared based on a Docket No. UE 180 (general rate case, or GRC) MONET run. The RVM results are not the appropriate basis for an adjustment because the RVM does not include Port Westward at all, and the RVM and GRC runs are based on hourly power cost figures which differ by a 1.9% line loss factor, as discussed on Pages 53-54 of

PGE Exhibit 400. Use of the higher power cost figures in the RVM run is a contributing factor to ICNU's overstatement of Port Westward margins.

F. Conclusion – Forecast Adjustments and Variance Tariff

Q. Do you have a common observation on the three test year NVPC forecast reductions that parties propose (extrinsic value, forced outage rates and ancillary services)?

A. Yes. All three are examples of the uncertainty that permeates forecasting test year NVPC. With respect to much of this forecast, we – collectively – simply do not know what will happen and so we make a series of assumptions. The gap between these assumptions and reality is the risk both PGE and our customers share: that cost of service prices based on the NVPC forecast will be more or less than cost of service prices based on the actual costs. Reducing the test year NVPC forecast by these assumed amounts, however, disproportionately affects PGE's risk compared to customers. All else being equal, lowering the forecast lowers customers' risk: the probability of actual NVPC that are less than the forecast and the potential size of any such variance. Conversely, lowering the forecasts increases PGE's risk: the probability of actual NVPC that are higher than the forecast and the potential size of any such variance.

Q. What do you believe is the best regulatory framework for addressing the uncertainty associated with extrinsic value and ancillary services?

A. These two uncertainties reflect theoretical "value" residing within PGE's resource portfolio that we may or may not be able to realize on an operational basis depending on numerous other variables not the least of which is the amount of electricity our customers demand and when they demand it. In other words, it is difficult to imagine PGE obtaining these benefits without experiencing other operating circumstances that cause actual NVPC to vary from forecasted NVPC. In some years, we may receive none of this value. In other years, we may achieve some but only because of circumstances that otherwise significantly increase our actual NVPC; that is, the benefits mitigate but do not eliminate the increase in NVPC. These are examples of the general principle that PGE's exposure to higher NVPC than forecast is greater than its exposure to lesser NVPC than forecast.[4] We believe the best regulatory framework to reflect the operational "value" of our resource portfolio in cost of service is our Variance Tariff. Customers will receive 90% of the benefits of this value that we can achieve operationally; the 10% we receive is ample to ensure our interest in pursuing it. Our Variance Tariff also includes other factors which can result in differences between forecasted and actual NVPC.

The power cost adjustment mechanisms Staff and CUB propose, on the other hand, would leave most of the initial shift of risk created by reducing the forecast NVPC by these uncertain amounts with PGE because of the large deadbands in these proposals. ICNU's position would leave with PGE all of the risk created by including these amounts in the forecast.

Q. Do you believe that PGE's proposed Variance Tariff also is the best response to the issue of what forced outage rate to assume for PGE's thermal generating plants?

[4] See pages 7-39 through 8-45 of PGE Exhibit 1803, which is a copy of a report from PA Consulting.

A. Yes, although for different reasons. The rolling four-year average methodology already, roughly, mitigates the risk for customers and PGE that variances between assumed and actual forced outage rates will cause actual NVPC to be lower or higher, respectively, than forecasted. If the forced outage rate in a given year is lower than assumed, customers will experience that actual result over the subsequent four years (lagged by a year) and vice versa for PGE. The Variance Tariff, under these circumstances, simply increases the mitigation by removing some of the randomness associated with market prices varying significantly over any given four-year period.

If the Commission adopts the use of NERC data for forecasting assumed forced outage rates, however, it becomes more important to adopt PGE’s Variance Tariff because nothing now mitigates this risk for PGE or customers. Although the methodology results in a lower forecasted NVPC in 2007, it could well result in a higher test year forecasted NVPC, increasing the risk to customers that actual NVPC will be lower than this forecast. The Variance Tariff will reduce the risk the NERC methodology would create over the status quo.

V. Timing and Prudence of Port Westward

Q. What concerns does CUB raise about the potential for a delay in Port Westward's on-line date?

A. CUB is concerned that the test year revenue requirement the Commission approves in Docket No. UE 180 may be stale by the time Port Westward comes on line if PGE experiences a delay in commercial operation (CUB/200, Jenks-Brown/29-30). To address this concern, CUB recommends that the Commission impose three conditions:

1. "The tariff associated with Port Westward is only valid within 30 days of March 1, 2007." (CUB/200, Jenks-Brown/30).
2. "If Port Westward is not use[d] and useful within 30 days, the Company must reopen UE 180" and other parties "should be given a limited period of time to review the Company's actual costs to determine whether there is new information that requires a reexamination of PGE costs…" (CUB/200, Jenks-Brown/30-31).
3. "After six months, if Port Westward is not used and useful, the Company must file a new rate case in order to add the plant to rate base" (CUB/200, Jenks-Brown/31).

Q. Are these conditions reasonable?

A. No. 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.

Q. CUB criticizes PGE for requesting inclusion of Port Westward in PGE's cost of service prices without providing an update on PGE's actions pursuant to the entire 2002 IRP Final Action Plan (CUB/200, Jenks-Brown/25-26). Is this criticism valid?

A. No. PGE has consistently provided Final Action Plan updates to all parties to LC 33, the docket under which the Commission acknowledged PGE's Final Action Plan. On March 23, 2006, PGE submitted an LC 33 compliance filing, which went to all parties in that docket, including CUB. We include this filing as PGE Exhibit 1915. That update stated that:

> PGE is pleased to report that it has achieved all of the energy and capacity resource targets in our acknowledged Final Action Plan except for an additional 38 MWa of wind energy, for which negotiations are proceeding.

The update also provided the following table:

Table 8
Presented in PGE Final Action Plan Update March 23, 2006

Energy Portfolio Actions	**2002 IRP Action Plan**		**Resource Acquired to Date**	
	2007 MWa	2007 MW	MWa	MW
Short-term Acquisitions[1]	125	125	125	125
Plant Upgrades	41	50	36	41
Other Operating Changes[2]	5	0	5	0
Hydro Contract Extension[3]	14	116	14	116
EE per the Energy Trust of Oregon[4]	55	79	34	49
Fixed Price PPAs	135	150	132	150
Wind (assumes capacity value = energy) [5]	65	65	27	27
Port Westward	350	375	360	382
Total Energy Actions	790	960	733	890
Additional Capacity Actions				
Dispatchable Standby Generation		30		45
Port Westard Duct Firing		25		25
Peak Tolling from Bids		400		400
Fill-in Short-Term from the Market1		500		500
Total Additional Capacity Actions		955		970

1 Purchased as needed to balance resources to load.
2 Represents PGE's expectation of ongoing operation of the Bull Run hydro project.
3 2002 IRP Target included an additional 49 MWa of energy at market index price, which is included here in the 125 MWa of short-term acquisitions. Total energy from hydro contract extension is 63 MWa.
4 ETO target of 55 MWa is for acquisitions through 12/31/2007; 34 MWa acquired is for 2004 and 2005. MW savings are estimates based on implied load factors.
5 PGE is continuing negotiations with two wind bidders to acquire the remaining 38 MWa.

Q. As of the March 23, 2006, update, what actions did PGE still need to take to meet the overall Final Action Plan requirements?

A. PGE only had to complete its targeted acquisition of wind resources by acquiring an additional 38 MWa.

Q. Has PGE now completed this acquisition?

A. Yes. PGE is in the process of developing the first phase of the Biglow Canyon Wind Farm in Sherman County, Oregon. This first phase is 126 MW, or 47 MWa.

Q. Has the Commission issued orders related to Biglow Canyon?

A. Yes. In Order No. 06-293, the Commission approved certain utility property sale and lien-related provisions related to Biglow Canyon, pursuant to ORS 757.480. In

Order No. 06-419, the Commission issued a waiver to OAR 860-038-0080(1)(b) for Biglow Canyon.

Q. Has PGE also met the additional conditions the Commission imposed in Order No. 04-375 acknowledging PGE's Action Plan?

A. Yes. Pages 14-18 of PGE's 2002 IRP Final Action Plan Update explain how PGE has met the conditions. PGE filed the Update on March 23, 2006, and also distributed it to participants in its first 2006 IRP Public Meeting on April 12, 2006.

VI. Beaver 8

Q. How much of the rate base and associated depreciation in PGE's original filing in this docket were associated with the transfer of the Beaver 8 regulatory asset to rate base?

A. In the March filing, we included a January 1, 2007, balance of approximately $7.0 million, with depreciation based on the expected life of the plant.

Q. What was the basis for this treatment?

A. Pursuant to a 2004 stipulation between PGE, Staff, and CUB, the balance of the Beaver 8 regulatory asset was to go into rate base on the effective date of rates set in PGE's next general rate case (i.e., this case), if the Commission has issued an order (in Docket UM 1066) allowing addition of new rate base assets on a cost basis by the time rates are to go into effect.

Q. Has the Commission issued a UM 1066 order?

A. No.

Q. What will PGE do if the Commission has not issued a UM 1066 order by the time rates in this proceeding are to go into effect, or issues an order which does not allow the addition of new rate base assets on a cost basis?

A. We will continue to collect the Beaver 8 regulatory asset through Tariff Schedule 105. We will also remove the corresponding amount from the test year rate base. Finally, we will remove the associated depreciation for the test year revenue requirement.

VII. Rate Case Margin and Effective Tax Rate for AR 499/SB 408

Q. How will the results of UE-180/UE-181/UE-184 be used to determine the tax true-up for AR 499 purposes?

A. The Commission has determined (Order 06-400, pgs. 9-10) that the use of ratios for the net to gross revenues (i.e., margin) and effective tax rates as determined in ratemaking proceedings should be used to determine actual taxes collected for the AR 499 tax true-up.

Q. Have you calculated these ratios?

A. Yes, Exhibit 1916 provides the calculations based on PGE's filed case adjusted for the O&M and Depreciation stipulations as well as the updated net variable power cost forecast filed in August. The results, however, should be updated based on the final Commission Order(s) in this case.

Q. What are the results of these calculations?

A. Based on these results, the rate making margin and effective tax rate are 11.92% and 39.23%, respectively.

Q. Should these be the ratios that are used by the Commission to determine taxes in rates for the AR 499 true-up?

A. No. The Commission should consider the impact of disallowed costs in determining the effective tax rate and margin for AR 499 purposes. To do otherwise would effectively allow customers to receive tax benefits from utility costs for which customers are not responsible.

Q. Have you determined how these ratios should be adjusted?

A. Yes. Exhibit 1916 also provides the adjusted margin and effective tax rate after taking disallowed costs into account.

Q. Please describe the adjustments that were made?

A. We adjusted for utility costs that were not included in PGE's revenue requirement on the basis that the type of cost is subject to either limited, or no, cost recovery. The adjustments include:

- Adding SERP costs
- Adding MDCP costs
- Adding Category C advertising costs
- Adding Category A advertising costs in excess of 1/8 of 1%, per the O&M stipulation between PGE, Staff, CUB, and ICNU.
- Adding the disallowed portion of wage and salaries per application of the three-year wage model as agreed to in the O&M stipulation between PGE, Staff, CUB, and ICNU.
- Adding the disallowed portion of incentive pay as agreed to in the O&M stipulation between PGE. Staff, CUB, and ICNU.
- Adding the disallowed portion of corporate memberships and dues as agreed to in the O&M stipulation between PGE, Staff, CUB, and ICNU.

Q. Could other adjustments have been made?

A. Possibly. For example, we did not include below-the-line costs such as state and federal lobbying expense. However, it could be argued that, like disallowed utility costs, such expenses create tax benefits under AR 499 that would otherwise flow to customers even though customers are not responsible for the underlying cost that creates those benefits.

Q. What are the results of your proposed adjustments?

A. PGE's adjusted ratemaking margin and effective tax rate are 10.96% and 39.22%, respectively.

Q. Do these figures require updating later in the process?

A. Yes. Just as the unadjusted figures would require an update for Commission Order(s) regarding the stipulations and contested issues that remain in this case, so too do the adjusted figures.

Q. Is PGE suggesting that its revenue requirement be adjusted for these items?

A. No. PGE is not suggesting the Commission alter PGE's revenue requirement for the effect of these disallowances. Rather, we are requesting that the Commission recognize that certain utility costs will not be recovered in this proceeding, and therefore, to avoid giving customers tax benefits from such costs, the margin and effective tax rate ratios should be adjusted for purposes of future AR 499 tax true-up proceedings.

VIII. Qualifications

Q. Mr. Drennan, please state your educational background and experience.

A. I received a Bachelor of Science in Economics from the University of Wyoming in August 1995. I also completed the coursework for a Master of Science in Regulatory Economics. From 1999 to 2001, I worked for the Iowa Department of Justice – Office of Consumer Advocate, as a Utility Analyst. While there I prepared and presented testimony to the Iowa Utilities Board in several utility-related dockets. Between 2001 to 2002 I worked for two energy consulting firms: Energy Resource Consulting, based in Denver, as a Supervising Economist, and EES Consulting, based in Seattle, as a Senior Analyst. In 2002, I joined PGE in the Rates and Regulatory Department. My current position is a business analyst in the Regulatory Affairs department.

Q. Does this conclude your testimony?

A. Yes.

1 **List of Exhibits**

PGE Exhibit	**Description**
1901	Referenced Morgan Deposition Pages
1902	Application of Staff/CUB PCA Proposals to PGE
1903	PCA Examples
1904	Referenced Wordley Deposition Pages
1905	Extrinsic Value Example
1906-C	**(Confidential – Provided under separate cover)** Corrected Extrinsic Value Analysis from ICNU Exhibit 103
1907	Explanation of Errors in ICNU Analysis
1908-C	**(Confidential – Provided under separate cover)** Comparison of Monet and Corrected ICNU Approach
1909	Non-confidential Portion of PGE Responses to ICNU Data Request Nos. 125-126
1910	PGE Responses to ICNU Data Request Nos. 161-162
1911	ICNU Response to PGE Data Request No. 015
1912	NERC Benchmarking Material
1913	NERC Combined-Cycle Performance Data
1914	Neutrality of “Phantom Open” Position
1915	2002 IRP Final Action Plan Update Filing
1916	Rate Making Margin and Effective Tax Rate for AR 499
1917	Production Rate Base Earnings Power

with a power cost recovery mechanism be more or less risk than a utility without a power cost recovery mechanism?

A Are we assuming utilities that have a large amount of exposure to the market? Or -- I don't know if I could answer that question.

Q How about whether or not a utility is subject to a consolidated tax adjustment for ratemaking purposes in the various jurisdictions in which they operate? Is that something that you would take my account?

A When I made my sample selection I did not take that into account.

Q So you're not aware whether any of the utilities in your sample group are subject to a consolidated tax adjustment?

A No.

Q How about reliance on the wholesale market or a percentage of power supply for purchased power? Is that a relevant consideration?

A On --

Q In term determining your sample group of companies.

A It was not.

Q Do you know what the percentage of power

supplier of PGE is for purchased power?
A Not the exact figure, no.
Q Did you consider at all the utilities in your sample group of companies what percentage of their power supply comes from purchased power?
A No.
Q What about regulatory climates? I noticed on page --
MS. ANDRUS: Before you finish your question, could we please take a break?
MR. VAN NOSTRAND: Yeah.
MS. ANDRUS: Thank you.
MR. VAN NOSTRAND: Would you like five minutes?
MS. ANDRUS: Sure.
(Recess)
BY MR. VAN NOSTRAND:
Q If I could direct your attention to Exhibit 1002, page 6, the column Expected Return on Equity, below the line there you used 12.0 percent. Can you explain where that number comes from?
A It's actually part of the sensitivity analysis that those inputs are what I would consider to be the high end of the range. And the sensitivity analysis on page 7 gives the rest of the range. So

Application of Staff/CUB PCA Proposals to PGE
Based on UE 115, 2003, 2004 and 2005 RVMs
Dollars in $000s

UE-115 Rate Base	1,766,581
UE-115 Equity Share	52.18%
UE-115 Marginal TR	39.33%
NTG Factor	1.648
100 BP of ROE	$ 15,194

CUB Mechanism:

Cumulative Variance:	Higher Costs		Lower Costs	
Dead Band	37,984	250 BP	(18,992)	125 BP
50/50 Sharing	60,775	150 BP more	(30,387)	75 BP less
90/10	Beyond		Beyond	

Staff Mechanism:

Cumulative Variance:	Higher Costs		Lower Costs	
Dead Band	22,791	150 BP	(22,791)	150 BP
90/10 Sharing	Beyond		Beyond	

	2002	2003	2004	2005	Total Customer Collection	Total Shareholder Absorbed
Actual Unit NVPC	41.35	25.97	24.91	28.43		
Forecast Unit NVPC	35.64	24.19	25.14	26.44		
Difference	5.71	1.78	(0.23)	1.99		
Forecast Load (000 MWh - busbar)	19,574	16,096	15,457	16,294		
Actual Load (000 MWh - busbar)	16,507	16,286	16,189	16,437		
Earnings Test Adjusted ROE	5.69%	7.69%	11.67%	6.64%		
UE-115 Less 100 BP	9.50%	9.50%	9.50%	9.50%		
Potential Dollar Recovery Up to 9.50	57,879	27,501	N/A	43,454		
Potential Dollar Refund Down to 11.5	N/A	N/A	(2,583)	N/A		
Staff Mechanism:						
Variance (Unit NVPC(A) - Unit NVPC	111,745	28,649	(3,520)	32,370		
Deadband	(22,791)	(22,791)	(22,791)	(22,791)		
Residual	88,954	5,859	Within DB	9,580		
Deferred Amount	80,059	5,273	-	8,622		
Max Recovery per Earnings	57,879	27,501	(2,583)	43,454	**71,773**	**97,471**
Deferral Mitigated by Earnings	Yes	No	No	No		
Regulated ROE after mechanism	9.50%	8.04%	11.67%	7.21%		
CUB Mechanism (Assume Variance Calc As Staff):						
Variance	111,745	28,649	(3,520)	32,370		
Deadband	(37,984)	(37,984)	18,992	(37,984)		
Residual	73,761	Within DB	Within DB	Within DB		
Amount subject to 50/50	22,791	-	-	-		
Amount subject to 90/10	50,970	-	-			
Deferred Amount	57,268	-	-	-		
Max Recovery per Earnings	57,879	27,501	(2,583)	43,454	**57,268**	**111,976**
Deferral Mitigated by Earnings	No	No	No	No		
Regulated ROE after mechanism	9.46%	7.69%	11.67%	6.64%		
PGE Mechanism:						
Variance (Unit NVPC(A) - Unit NVPC	$ 94,233	28,988	(3,686)	32,655		
Deferral at 90%	84,809	26,089	(3,317)	29,389	**136,971**	**15,219**
Earnings Before Deferral	5.69%	7.69%	11.67%	6.64%		
Regulated ROE after mechanism	11.27%	9.41%	11.45%	8.57%		
Earnings Cap/Floor	11.50%	11.50%	9.50%	11.50%		
Deferral Mitigated by Earnings	No	No	No	No		

Application of Staff/CUB PCA Proposals to PGE
Based on UE 115 (Assume no RVMs)
Dollars in $000s

UE-115 Rate Base		1,766,581
UE-115 Equity Share		52.18%
UE-115 Marginal TR		39.33%
NTG Factor		1.648
100 BP of ROE	$	15,194

CUB Mechanism:

Cumulative Variance:	Higher Costs		Lower Costs	
Dead Band	37,984	250 BP	(18,992)	125 BP
50/50 Sharing	60,775	150 BP more	(30,387)	75 BP less
90/10	Beyond		Beyond	

Staff Mechanism:

Cumulative Variance:	Higher Costs		Lower Costs	
Dead Band	22,791	150 BP	(22,791)	150 BP
90/10 Sharing	Beyond		Beyond	

	2002	2003	2004	2005	Total Customer Collection (Refund)	Total Shareholder Absorbed
Actual Unit NVPC	41.35	25.97	24.91	28.43		
Forecast Unit NVPC	35.64	35.64	35.64	35.64		
Difference	5.71	(9.68)	(10.73)	(7.22)		
Forecast Load (000 MWh - busbar)	19,574	19,574	19,574	19,574		
Actual Load (000 MWh - busbar)	16,507	16,286	16,189	16,437		
Earnings Test Adjusted ROE	5.69%	19.06%	21.91%	15.07%		
UE-115 Less 100 BP	9.50%	9.50%	9.50%	9.50%		
Potential Dollar Recovery Up to 9.50%	57,879	N/A	N/A	N/A		
Potential Dollar Refund Down to 11.50%	N/A	(114,920)	(158,228)	(54,300)		
Staff Mechanism:						
Variance (Unit NVPC(A) - Unit NVPC(F))	111,745	(189,422)	(210,015)	(141,237)		
Deadband	(22,791)	22,791	22,791	22,791		
Residual	88,954	(166,631)	(187,225)	(118,447)		
Deferred Amount	80,059	(149,968)	(168,502)	(106,602)	**(269,569)**	**(159,361)**
Max Recovery per Earnings	57,879	N/A	N/A	N/A		
Max Refund per Earnings	N/A	(114,920)	(158,228)	(54,300)		
Deferral Mitigated by Earnings	Yes	Yes	Yes	Yes		
Regulated ROE after mechanism	9.50%	11.50%	11.50%	11.50%		
CUB Mechanism (Assume Variance Calc As Staff):						
Variance	111,745	(189,422)	(210,015)	(141,237)		
Deadband	(37,984)	37,984	37,984	37,984		
Residual	73,761	(151,438)	(172,031)	(103,253)		
Amount subject to 50/50	(22,791)	22,791	22,791	22,791		
Amount subject to 90/10	50,970	(128,647)	(149,240)	(80,462)		
Deferred Amount	57,268	(127,178)	(145,712)	(83,811)	**(257,663)**	**(171,267)**
Max Recovery per Earnings	57,879	N/A	N/A	N/A		
Max Refund per Earnings	N/A	(114,920)	(158,228)	(54,300)		
Deferral Mitigated by Earnings	No	Yes	No	Yes		
Regulated ROE after mechanism	9.46%	11.50%	12.32%	11.50%		
PGE Mechanism:						
Variance (Unit NVPC(A) - Unit NVPC(F))	94,233	(157,603)	(173,693)	(118,601)		
Deferral at 90%	84,809	(141,843)	(156,323)	(106,741)	**(298,044)**	**(57,620)**
Max Recovery per Earnings	88,266	N/A	N/A	N/A		
Max Refund per Earnings	N/A	(145,307)	(188,615)	(84,687)		
Deferral Mitigated by Earnings	No	No	No	Yes		
Regulated ROE after mechanism	11.27%	9.73%	11.63%	9.50%		

PCA Examples
Variance Tariff

Assumptions:

Total NVPC (000)	$800,000		
Load (000 MWh)	20,000	Structure:	
Forecast Avg NVPC ($/MWh)	40.00		(Actual Avg NVPC - Forecast Avg NVPC) * Actual Load

Cost Change	Load Change	Load Delta	NVPC Delta	Total Load	Total NVPC	Actual Avg NVPC	Delta Avg NVPC	PCA Revenue	Delta Energy Rate Revenue*	Total Rev Change	Net Change
	Average NVPC =			40.00							
	Market Power =			60.00							
0%	5%	1000	$60,000	21,000	$860,000	40.95	0.95	20,000	$ 40,000	$ 60,000	($0)
0%	-5%	-1000	-$60,000	19,000	$740,000	38.95	-1.05	-20,000	$ (40,000)	$ (60,000)	$0
10%	0%	0	$80,000	20,000	$880,000	44.00	4.00	80,000	$ -	$ 80,000	$0
-10%	0%	0	-$80,000	20,000	$720,000	36.00	-4.00	-80,000	$ -	$ (80,000)	$0
10%	5%	1000	$140,000	21,000	$940,000	44.76	4.76	100,000	$ 40,000	$ 140,000	$0
10%	-5%	-1000	$20,000	19,000	$820,000	43.16	3.16	60,000	$ (40,000)	$ 20,000	($0)
-10%	5%	1000	-$20,000	21,000	$780,000	37.14	-2.86	-60,000	$ 40,000	$ (20,000)	$0
-10%	-5%	-1000	-$140,000	19,000	$660,000	34.74	-5.26	-100,000	$ (40,000)	$ (140,000)	$0
	Average NVPC =			40.00							
	Market Power =			30.00							
0%	5%	1000	$30,000	21,000	$830,000	39.52	-0.48	-10,000	$ 40,000	$ 30,000	$0
0%	-5%	-1000	-$30,000	19,000	$770,000	40.53	0.53	10,000	$ (40,000)	$ (30,000)	$0
10%	0%	0	$80,000	20,000	$880,000	44.00	4.00	80,000	$ -	$ 80,000	$0
-10%	0%	0	-$80,000	20,000	$720,000	36.00	-4.00	-80,000	$ -	$ (80,000)	$0
10%	5%	1000	$110,000	21,000	$910,000	43.33	3.33	70,000	$ 40,000	$ 110,000	$0
10%	-5%	-1000	$50,000	19,000	$850,000	44.74	4.74	90,000	$ (40,000)	$ 50,000	$0
-10%	5%	1000	-$50,000	21,000	$750,000	35.71	-4.29	-90,000	$ 40,000	$ (50,000)	$0
-10%	-5%	-1000	-$110,000	19,000	$690,000	36.32	-3.68	-70,000	$ (40,000)	$ (110,000)	$0

* NVPC portion of energy rate

PCA Examples
Staff Proposal

Assumptions:

Total NVPC (000)	$800,000		
Load (000 MWh)	20,000	Structure:	
Forecast Avg NVPC ($/MWh)	40.00		(Actual Avg NVPC - Forecast Avg NVPC) * Rate Case Load

Cost Change	Load Change	Load Delta	NVPC Delta	Total Load	Total NVPC	Actual Avg NVPC	Delta Avg NVPC	PCA Revenue	Delta Energy Rate Revenue*	Total Rev Change	Net Change
	Average NVPC =			40.00							
	Market Power =			60.00							
0%	5%	1000	$60,000	21,000	$860,000	40.95	0.95	19,048	$ 40,000	$ 59,048	$ (952)
0%	-5%	-1000	-$60,000	19,000	$740,000	38.95	-1.05	-21,053	$ (40,000)	$ (61,053)	$ (1,053)
10%	0%	0	$80,000	20,000	$880,000	44.00	4.00	80,000	$ -	$ 80,000	$ -
-10%	0%	0	-$80,000	20,000	$720,000	36.00	-4.00	-80,000	$ -	$ (80,000)	$ -
10%	5%	1000	$140,000	21,000	$940,000	44.76	4.76	95,238	$ 40,000	$ 135,238	$ (4,762)
10%	-5%	-1000	$20,000	19,000	$820,000	43.16	3.16	63,158	$ (40,000)	$ 23,158	$ 3,158
-10%	5%	1000	-$20,000	21,000	$780,000	37.14	-2.86	-57,143	$ 40,000	$ (17,143)	$ 2,857
-10%	-5%	-1000	-$140,000	19,000	$660,000	34.74	-5.26	-105,263	$ (40,000)	$ (145,263)	$ (5,263)
	Average NVPC =			40.00							
	Market Power =			30.00							
0%	5%	1000	$30,000	21,000	$830,000	39.52	-0.48	-9,524	$ 40,000	$ 30,476	$ 476
0%	-5%	-1000	-$30,000	19,000	$770,000	40.53	0.53	10,526	$ (40,000)	$ (29,474)	$ 526
10%	0%	0	$80,000	20,000	$880,000	44.00	4.00	80,000	$ -	$ 80,000	$ -
-10%	0%	0	-$80,000	20,000	$720,000	36.00	-4.00	-80,000	$ -	$ (80,000)	$ -
10%	5%	1000	$110,000	21,000	$910,000	43.33	3.33	66,667	$ 40,000	$ 106,667	$ (3,333)
10%	-5%	-1000	$50,000	19,000	$850,000	44.74	4.74	94,737	$ (40,000)	$ 54,737	$ 4,737
-10%	5%	1000	-$50,000	21,000	$750,000	35.71	-4.29	-85,714	$ 40,000	$ (45,714)	$ 4,286
-10%	-5%	-1000	-$110,000	19,000	$690,000	36.32	-3.68	-73,684	$ (40,000)	$ (113,684)	$ (3,684)

* NVPC portion of energy rate

PCA Examples
ICNU Proposal

Assumptions:

Total NVPC (000)	$800,000		
Load (000 MWh)	20,000	Structure:	
Forecast Avg NVPC ($/MWh)	40.00		Actual NVPC - Base NVPC - (Actual Loads - Base Loads)* Mrkt

Cost Change	Load Change	Load Delta	NVPC Delta	Total Load	Total NVPC	Actual Avg NVPC	Delta Avg NVPC	PCA Revenue	Delta Energy Rate Revenue*	Total Rev Change	Net Change
	Average NVPC =			40.00							
	Market Power =			60.00							
0%	5%	1000	$60,000	21,000	$860,000	40.95	0.95	0	$ 40,000	$ 40,000	$(20,000)
0%	-5%	-1000	-$60,000	19,000	$740,000	38.95	-1.05	0	$ (40,000)	$ (40,000)	$ 20,000
10%	0%	0	$80,000	20,000	$880,000	44.00	4.00	80,000	$ -	$ 80,000	$ -
-10%	0%	0	-$80,000	20,000	$720,000	36.00	-4.00	-80,000	$ -	$ (80,000)	$ -
10%	5%	1000	$140,000	21,000	$940,000	44.76	4.76	80,000	$ 40,000	$ 120,000	$(20,000)
10%	-5%	-1000	$20,000	19,000	$820,000	43.16	3.16	80,000	$ (40,000)	$ 40,000	$ 20,000
-10%	5%	1000	-$20,000	21,000	$780,000	37.14	-2.86	-80,000	$ 40,000	$ (40,000)	$(20,000)
-10%	-5%	-1000	-$140,000	19,000	$660,000	34.74	-5.26	-80,000	$ (40,000)	$ (120,000)	$ 20,000
	Average NVPC =			40.00							
	Market Power =			30.00							
0%	5%	1000	$30,000	21,000	$830,000	39.52	-0.48	0	$ 40,000	$ 40,000	$ 10,000
0%	-5%	-1000	-$30,000	19,000	$770,000	40.53	0.53	0	$ (40,000)	$ (40,000)	$(10,000)
10%	0%	0	$80,000	20,000	$880,000	44.00	4.00	80,000	$ -	$ 80,000	$ -
-10%	0%	0	-$80,000	20,000	$720,000	36.00	-4.00	-80,000	$ -	$ (80,000)	$ -
10%	5%	1000	$110,000	21,000	$910,000	43.33	3.33	80,000	$ 40,000	$ 120,000	$ 10,000
10%	-5%	-1000	$50,000	19,000	$850,000	44.74	4.74	80,000	$ (40,000)	$ 40,000	$(10,000)
-10%	5%	1000	-$50,000	21,000	$750,000	35.71	-4.29	-80,000	$ 40,000	$ (40,000)	$ 10,000
-10%	-5%	-1000	-$110,000	19,000	$690,000	36.32	-3.68	-80,000	$ (40,000)	$ (120,000)	$(10,000)

* NVPC portion of energy rate
This analysis assumes that the actual market prices experienced in adjusting load equals that used in adjustment calculation

prim- -- and I think we've identified here what inputs we're talking about, right on lines 3 and 4 there on page 2.

Q So the primary inputs would be system loads, electricity and natural gas prices, hydroelectric generation, and thermal unit availability? Is that correct?

A Correct.

Q I'm unclear what you mean by deriving the inputs stochastically. I had assumed that you put inputs and relationships into a model and the stochastic modeling used those relationships to produce a set of outputs. Is that accurate?

A No.

Q Then perhaps you should assume that I don't know what stochastic modeling is and start me at the beginning and take me through the output --

A Okay.

Q -- stage, if you would.

A The model -- the model stays the same. In deterministic power cost modeling or stochastic power cost modeling. It's the inputs that change. Only not -- not -- the same inputs, but the values of the inputs change. It's the values of the inputs that change. And they change by drawing the inputs from a -- from statistical distributions.

Then I guess the final piece is you make -- you make a number of runs, with the various inputs through this same model, and then you average -- or you -- the runs, the results of the runs, you make a distribution of those net variable power cost results, and then you know what the distribution looks like. Which we don't know now. That's why we think it's a good idea to do this.

And hopefully you'd have an expected value, which would be the average of that distribution.

Expected value potentially could be used as the base net variable power cost in rates.

Q Over what period of time would you make your distributions?

A That's part of the development effort. We haven't done the modeling. We haven't -- we've only proposed it. You determine what period of time, after you got into the work of developing the modeling.

Q So it might be as short as a year?

A I doubt if it would be as short as a year, although I don't know how long it would be. A year probably wouldn't be enough.

Q Statistically what would be the correct number of years to use?

A I don't know.
Q So you don't know whether it would be five?
A A range of years. It would be more than one, and, um, enough years that people could agree were -- were reasonable.
Q Well, if you have hydro determined over 66 water years, as it has been in the past, would you use 66 years for your stochastic modeling too?
A I don't know.
Q Okay. Do I understand you to say that the output will be a distribution of power costs over some period of time?
A Well --
Q In fact, tell me -- let me stop there. You tell me what a distribution of power costs. Let's take a 5-year, let's do a 5-year model. What's the -- and a number of runs. What's the distribution of power costs gonna show me?
A Well, for ratemaking purposes we'd be focusing on one year. So you're modeling one year, probably would be a future year. So that's the number of years you're modeling.
How many runs you make, you'd make a lot of runs: a hundred, a thousand, maybe. Enough so that you got a distribution that was stable.

BY MR. MORGAN:

Q Does Staff have the stochastic modeling tools necessary to perform the risk analysis you just discussed for ratemaking purposes?

A No.

Q Do you know whether PGE possesses those?

A No.

Q Okay. Looking at Integrated Resource Planning, isn't it true that utilities engaged in IRPs are looking at long-term costs?

MS. ANDRUS: Objection; ambiguous. Do you mean is that the only thing they're looking at?

BY MR. MORGAN:

Q Let me ask it this way. What is the essential decision to be made in selecting resources in integrated resource planning?

A Well, I think there are -- my understanding, and I haven't --

Q That's all I'm asking for, is your understanding.

A And I haven't been sitting in on recent processes, IRP processes. But my general understanding is that the objective is to minimize present-value revenue requirement, and also minimize risk. And there's a tradeoff between those two.

such as a take-and-pay contract, might it have negative extrinsic value?

A I'm not familiar with that -- I don't -- I haven't thought about it.

Q If we look at PGE's entire system, from acquisition of supply, through distribution and use, all the way from top to bottom, where do you think the greatest optionality in that system lies?

A In its gas-fired power plants.

Q Okay. Let me suggest that PGE's customers have the greatest optionality. And by that I mean they have the ability to take or not take as little or as much electricity from PGE at any time that they want, in general, for a fixed kilowatt hour price. Would you agree that that right is substantial optionality?

A Yes.

Q Would you agree that it has value to each customer that has that optionality?

A It may, yeah.

Q Can you think of a customer for whom it doesn't have that value?

A No.

Q Okay. Does PGE need flexible resources in order to provide its customers, to meet the particularly the answer beginning on line 16 where you say, "If the company successfully implemented stochastic power cost modeling, there would no longer be a need for staff's proposed extrinsic value adjustment."

Is that another way of saying that your extrinsic value adjustment is a substitute for stochastic modeling?

A No, it's not a complete substitute.

Q Do you know whether stochastic modeling would produce the same result as Staff's proposed extrinsic value adjustment?

A I don't even know what you're talking about, actually. How you'd make that comparison.

Q Well, let's look at your answer on line 16 in which you've said, "If the company successfully implemented stochastic power cost modeling, there would no longer be a need for staff's proposed extrinsic value adjustment." So it would appear that you believe something about stochastic power cost modeling takes into account the extrinsic value you're otherwise seeking as adjustment here; is that correct?

A (Nods head) yes. Stochastic modeling does away with the need for extrinsic value adjustment.

Q Would stochastic modeling value the

optionality that is the basis for your extrinsic value adjustment in the -- at the same value that you have placed on it in this docket?

A I have no idea. Conceptually it would capture. Quantitatively, I don't know how to determine that or make that connection. But conceptually it would capture the extrinsic value of resources.

Q I think one last question. Are you aware of any regulatory commission that has used stochastic modeling to set -- test your power costs?

A No.

Q Okay. I think we're through.

A Okay.

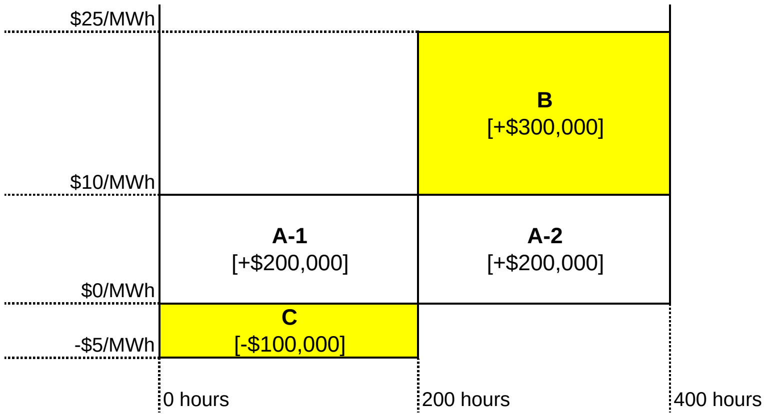
MS. ANDRUS: I have no questions. And we'd like to review the transcript for corrections. I'd like a copy.

(Proceedings adjourned at 3:10 p.m.)

Extrinsic Value Example

Forecast NVPC	850,000	000s
Forecast Load	2,400	aMW
Average Price	40.4	mills/kwh
Other Rev Req	800,000	000s
Forecast Load	2,400	aMW
Average Price	38.1	mills/kwh
Total Retail Tariff	78.5	mills/kwh
<u>Forecast January:</u>		
Beaver Output	0	For example, as it was in Mar 15 Filing
Sumas Gas Price	9.80	$/mmbtu
Mid-C On Peak	77.00	$/MWh
Mid-C Off Peak	68.75	$/MWh
Retail Load - Month	2700	aMW
<u>Weather Event:</u>		
Length of Storm	48	hours
Average Load	3200	aMW
Load above expected	500	aMW (Equals 3,200 - 2,700 aMW)
Energy to be filed	24,000	MWh
Avg Sumas Price	12.00	$/mmbtu (Over 48 hours)
Avg Mid-C Price	144.00	$/MWh (Over 48 hours)
Approx Beaver HR	9.500	mmbtu/MWh
Approx Beaver Cap	500	MW
Value of Beaver Gen	3,456	Equals 500 MW * 48 hours * $144/MWh (in 000s)
Fuel Cost of Beaver	2,736	Equals 500 MW * 48 hours * 9.500 mmbtu / MWh * $12.00/mmbtu (in 000s)
Beaver Margin	720	Relative to Market (000s)
<u>Financial Impact of Load Excursion:</u>		
Additional Retail Rev	1,884	Equals 24,000 MWh * $78.50/Mwh (in 000s)
Additional Fuel Costs	2,736	Per Above
PGE Gross Margin	(852)	Loss of $.85 million from Load Excursion

Explanation of Error in ICNU Analysis -- Situation 1: Base Margin Positive



<u>Assume that:</u>
- The resource has a capacity of 100 MW.
- There are 400 hours in an on-peak monthly period.
- The base electric-gas spark spread from the monthly forward curves is $10/MWh.
- Expected spark spreads average $10/MWh, but vary, being $25/MWh during 200 hours, and -$5/MWh during the other 200 hours.

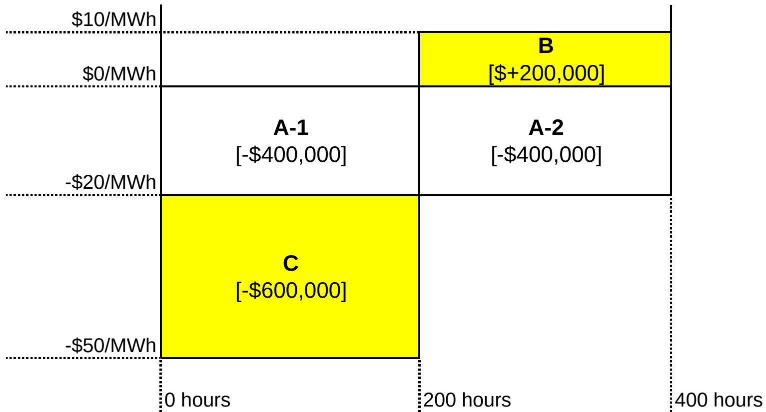
<u>Case 1: Monthly forward curve basis:</u>
- Plant runs all 400 hours.
- Margins for the monthly on-peak period are the sum of areas A-1 and A-2.
- Margins can also be calculated as 400 hours x 100 MW x $10/MWh, or $400,000.

<u>Case 2(a): Expected spark spreads, but no exercise of optionality:</u>
- Plant runs all 400 hours (even during hours when spark spread negative).
- Margins increase during 200 hours in which spread is $25/MWh -- by area B.
- Margins decrease during 200 hours in which spread is -$5/MWh -- by sum of area A-1 and absolute value of area C.
- Overall margins remain at $400,000, as area B is equal to the sum of area A-2 and the absolute value of area C.

<u>Case 2(b): Expected spark spreads, and exercise of optionality:</u>
- Plant runs only during 200 hours during which spark spread is positive.
- Company exercises option to not run the plant during the 200 hours when spark spread is negative.
- Margins increase during 200 hours in which spread is $25/MWh -- by area B
- Margins decrease during 200 hours in which spread is -$5/MWh -- by area A-1.
- Overall margins increase by $100,000, the difference between areas B and A-1, which is also equal to the absolute value of area C.
- Not running the plant when spread is -$5/MWh avoids a loss of area C.
- The absolute value of area C, or $100,000, is the option value.

<u>ICNU approach:</u>
- ICNU calculates option value as the sum of area B and the absolute value of area C.
- This approach overstates the option value by area B, or $300,000.

Explanation of Error in ICNU Analysis -- Situation 2: Base Margin Negative



Assume that:
- The resource has a capacity of 100 MW.
- There are 400 hours in an on-peak monthly period.
- The base electric-gas spark spread from the monthly forward curves is -$20/MWh.
- Expected spark spreads average -$20/MWh, but vary, being $10/MWh during 200 hours, and -$50/MWh during the other 200 hours.

Case 1: Monthly forward curve basis:
-- Plant does not run, because running would incur a loss of $800,000, or the sum of areas A-1 and A-2.

Case 2(a): Expected spark spreads, but no exercise of optionality:
- Plant continues to not run.
- Running all 400 hours would result in a loss of $800,000, or the sum of areas B, A-1, and C. This is equal to the hypothetical loss mentioned in Case 1.

Case 2(b): Expected spark spreads, and exercise of optionality
- Company exercises option to run the plant during the 200 hours during which spark spread is $10/MWh.
- Company continues to not run the plant during the 200 hours during which spark spread is negative.
- Overall margins increase by area B, or $200,000.
- Area B, or $200,000, is the option value.

ICNU approach:
- ICNU calculates option value as the sum of area B and the absolute value of area C.
- This approach overstates option value by the absolute value of area C, or $600,000.

July 10, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 8.125
Dated June 30, 2006
Question No. 125

Request:

Please explain why PGE entered into the PPM Cold Snap and PPM Superpeak contracts.

Response:

Commission Order No. 04-375 acknowledged PGE's 2002 IRP Final Action Plan. Page 13 of that order states that "acknowledged action items are: ………5. Acquire ……. 400 MW of tolling capability for peak purposes." To fulfill this action item to meet customers' capacity and reliability requirements, PGE selected the two best bids from the set of short-listed capacity bids submitted in response to its 2003 Request for Proposals. PGE provided bid pricing information for short-listed capacity bids in a confidential attachment to its response to OPUC Data Request No. 039 in Docket LC-33. Attachment 125-A to this response is a copy of the information in the confidential LC-33 attachment. Attachment 125-A is confidential and subject to Protective Order No. 06-111.

We selected the two largest sized bids shown in Attachment 125-A. Their prices were substantially lower, making them the least expensive alternative for meeting customers' capacity requirements.

July 17, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 8.126
Dated June 30, 2006
Question No. 126

Request:

When PGE initially considered the PPM Cold Snap and PPM Superpeak contracts, did it expect that the actual dispatch of these resources would be extremely rare? Please provide supporting documents.

Response:

The purpose of capacity resources is to meet extreme customer requirements of short duration. These resources are needed to meet PGE's obligation to provide reliable power to its customers. Given the role of capacity resources, we did not expect the Cold Snap and Superpeak contracts to dispatch frequently. See also PGE's responses to ICNU Data Request Nos. 127 and 130.

August 11, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 14.161
Dated July 28, 2006
Question No. 161

Request:

Please describe whether PGE's resources were sufficient to meet its peak load during the extreme heat experienced on July 21-23, 2006. In addition, please describe all measures that PGE implemented to meet its load on those days.

Response:

No. However, PGE's maintained resources and purchases, including emergency purchases, were sufficient to meet all obligations through the July 21-24 period. Although its installed capacity is not sufficient to meet peak demands, either in the summer or the winter, PGE prepares to meet extreme requirements through a combination of installed capacity, market purchases, and capacity contracts.

During the July 21-24 period, PGE also relied on the following:

- Dispatchable stand-by (diesel) generators
- Demand response (buy-back) program
- Draft of Timothy Lake
- License relief at the Deschutes River Project (Pelton and Round Butte facilities), which allowed additional generation during certain high-demand hours

Finally, on July 24, PGE declared a system emergency (NERC Alert 2) for hours 12 through 20. This resulted in the Bonneville Power Administration making additional resources available for purchase by PGE. A combination of both load- and resource-related events led up to PGE's system emergency declaration. Loads, both on PGE's system and in the West in general, were higher than anticipated, and several plant failures occurred, including one at Colstrip Unit 3.

In its response to ICNU Data Request No. 160, PGE included hourly load (including deliveries on behalf of ESSs) data for the July 21-24 period. Attachment 161-A provides hourly information for the same period, but from the perspective of the firm obligations that PGE was required to meet. These data differ from those in the No. 160 response in two ways – they do not include power scheduled by ESSs, but they do include reserve and regulation requirements. The net effect is an increase, i.e. the data in Attachment 161-A are greater than those in Attachment 159-A (which includes data responding to Request No. 160).

In summary, PGE meets its obligations, but does not maintain "extra" capacity resources. PGE was able to obtain resources to meet its obligations in every hour during the July 21-24 period. However, as noted above, it was necessary to declare a system emergency during a portion of July 24.

Attachment 161-A is confidential and subject to Protective Order No. 06-111. It is provided under separate cover.

August 11, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 14.162
Dated July 28, 2006
Question No. 162

Request:

Please discuss whether PGE believes that it has sufficient peaking resources on its system to meet the type of loads experienced July 21-23, 2006.

Response:

The quantity of PGE's peaking resources is consistent with the Commission-acknowledged (Order No. 04-375) Final Action Plan related to PGE's 2002 Integrated Resource Plan. These resources are sufficient to meet PGE's normal obligations, but are not excess. PGE relies on market purchases to ensure adequate supply during extreme peak days and hours, as well as in response to events such as low hydro availability or generation unit outages. As noted in PGE's response to ICNU Data Request No. 161, PGE was able to meet its obligations in every hour during the July 21-24 period, but it was necessary to declare a system emergency for a nine-hour period on July 24.

PGE has more capacity resources available in the winter. PGE's Attachment 159-A indicates that the top hour of expected 2007 winter load is approximately 450 MW higher than the top hour of expected 2007 summer load. This difference between expected winter and summer peaking requirements is approximately equal to the 400 MW combined capabilities of the Super-Peak and Cold-Snap winter capacity contracts.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

DOCKET NO. UE 180

ICNU'S RESPONSE TO PGE'S DATA REQUEST NO. 015

SEPTEMBER 6, 2006

Data Request No. 015:

What was ICNU's recommendation regarding Colstrip's forced outage rate in UE 179?

Response to Data Request No. 015:

ICNU objects to this request on the basis that it is not relevant and not likely to lead to the discovery of admissible evidence. Notwithstanding this objection, ICNU responds as follows.

ICNU did not make a specific recommendation regarding Colstrip's forced outage rate in UE 179. ICNU proposed a prudence adjustment that was applicable to all PacifiCorp plants.

Benchmarking Activities and Fees

GADS Home Page

GADS Services of the North American Electric Reliability Council (NERC) is pleased to provide electric generating unit benchmarking services to the electric industry.

Electric unit benchmarking is provided by a team of two experts: G. Michael (Mike) Curley of the NERC GADS Services staff and Robert R. (Bob) Richwine, Reliability Management Consultant. Biographies and work experiences of both Team members are shown at the end of this document.

The following descriptions present what services we can provide power generators and the cost for each service.

Introduction

Our benchmarking team begins the process by identifying peer groups to single units or groups of units operated by electric power owners. Whenever we benchmark a generating plant's performance, it is vital that we start by selecting a peer group that have as close a similarity in design and operating characteristics as possible. Certainly, we would never compare a fossil steam unit against a group that included nuclear, hydro or combined cycle units. However, many benchmarking programs have assumed that for fossil steam units, fuel type and size ranges are the proper select criteria. We have found from our extensive benchmarking studies that fuel types and especially the arbitrary size ranges (100-199MW, 200-299MW, etc.) are relatively much less statistically significant than other design and operational characteristics such as criticality, duty cycle, vintage, pressurized/balanced draft, etc. Because each individual unit is unique, our process ensures that the optimal peer group is selected; balancing the need for similarity in design and operations with the need for a large enough sample size for statistical validity. Without this objective analysis to find the optimal peer select criteria any conclusions drawn from the comparisons could very well be invalid and misleading.

By teaming with NERC, your company will gain the assurance that the results are objective and repeatable, with NERC having performed this service for over 12 years for US companies as well as for many international utilities. For many companies this has helped to ensure that the results are accepted throughout the organization and by their regulatory bodies.

It has been asked by others "but does it really make a difference?" To answer this we can look at a previous study that was done for the New England Power Pool in 1990 (the data is obviously out of date but should give an indication). As the study was undertaken we found that the most statistically significant factor was "criticality". Then within the supercritical group the next most important factor was "vintage".

SUPERCRITICAL FOSSIL UNITS Equivalent Forced Outage Rate (EFOR) – a measure of a unit's unreliability		
	EARLY VINTAGE	RECENT VINTAGE
EFOR (mean)	15.60 %	9.68 %
EFOR (median) (50th		

percentile)	12.17 %	8.08 %
EFOR (1st quartile) (25th percentile)	8.14 %	5.47 %

Clearly from this result it would be highly inappropriate to include recent vintage supercritical units in any peer population if the candidate unit was an early vintage supercritical unit, since it would be compared against units that had clearly benefited from the "learning curve" of the early vintage units.

In another study completed much recently, a fossil steam plant was analyzed to find its statistically appropriate peer groups. Here we can see that if we were to set a goal as the best quartile performers in our peer group, we would be setting unrealistically high expectations using the old criteria, compared to what we might set using the more appropriate peer group with new criteria.

EFOR - PLANT A (Coal; 800-1300MW)			
	OLD CRITERIA	NEW CRITERIA	% difference
mean	5.83%	7.63%	+31%
medial	4.55%	5.87%	+29%
best quartile	2.70%	3.97%	+47%

Clearly, these plants must have design and/or operational characteristics that create a more difficult challenge for their plant management to achieve the highest levels of reliability; a difficulty that might not be recognized through a benchmarking process that did not begin with a rigorous peer selection criteria analysis. Furthermore, the goals we might set using an inappropriate peer group may not be cost effective and we may end up spending more money than is justified to achieve these goals. Other plants studied have had just the opposite result. In those we may be setting our goals too low since the new peer group performs better than the one using the traditional criteria.

These examples are not isolated results. Rather we have found similar instances in virtually every analysis we have conducted including benchmarking studies of Nuclear, Hydro and other technologies. We firmly believe that if a benchmarking project is undertaken at all, it should start with an objective analysis to determine optimal peer unit characteristics.

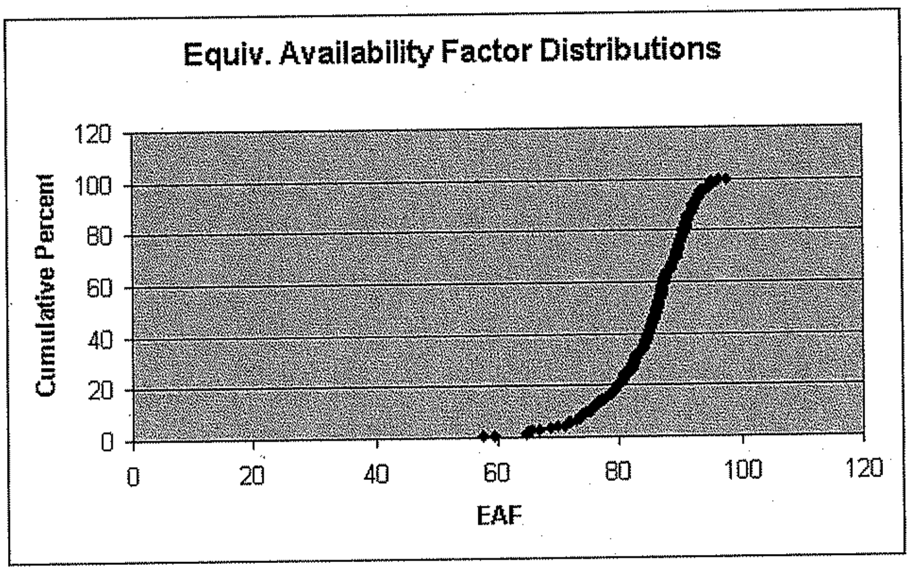
For a more complete description of the benchmarking procedure, please refer to the NERC Generating Availability Trend Evaluation (GATE) Working Group paper Predicting Generating Unit Reliability and World Energy Council (WEC) Case Study of the Month (CASOM). (See CASOM studies August 2002 and September 2003)

Fee Structure for Performance Benchmarking:

1. **Setup Fee:** For all benchmarking work, there is a $5,000 setup fee that covers the cost of preparing computer programs, phone consultation, and work forms used in the benchmarking process. It covers consultation for reviewing the fleet of units to be benchmarked and to divide the units into groups, if asked by the client. Although it is normally best to determine the optimal peer select criteria for each individual unit, in some cases a group of units operated by one company may be designed and operated in a similar manner so that an "average" for a group can be used in order to reduce costs.

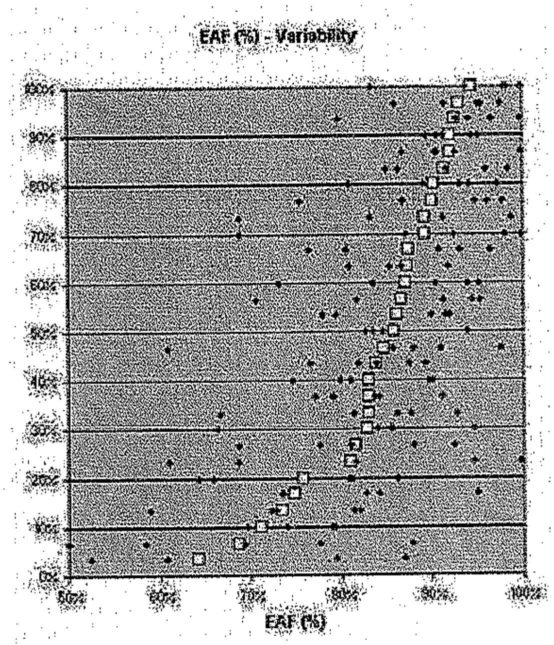
2. **Peer Criteria Selection Procedure:** Our first step in benchmarking is find the optimal balance between the need for as close a match as possible in the design and operating characteristics of the client's unit (or group of similar units) and the need for there to be enough units in the peer group for statistical validity. For each unit (or group of similar units) the fee is $1200.

3. **Performance Graphs and Tables:** Once the optimal select criteria is found, a set of tables and graphs are created for the performances indices selected. We normally use EFOR, SOF and EAF as the key indicators. However, we can provide additional graphs for any three indices wanted. Cost for the three-set is $600. If the client wants additional indices graphed, the cost is $200 per index. An example of these graphs is shown below.



4. **Variability Graphs and Tables:** We also offer a set of graphs and tables that show the make up of the mean values. The variability graphs (shown below) provide a year-by-year and mean value for each unit in the peer group. This allows the client to see the variation of a single index over the period of investigation. In the example below, the data was averaged over a five-year period. Therefore there are 5 annual and one 5-year average point.

The cost of each graph and its accompanying table is $200.



In this cumulative frequency graph for EAF the five-year average is rank ordered but the individual years for each unit are also shown in order to gain a perspective of EAF variability.

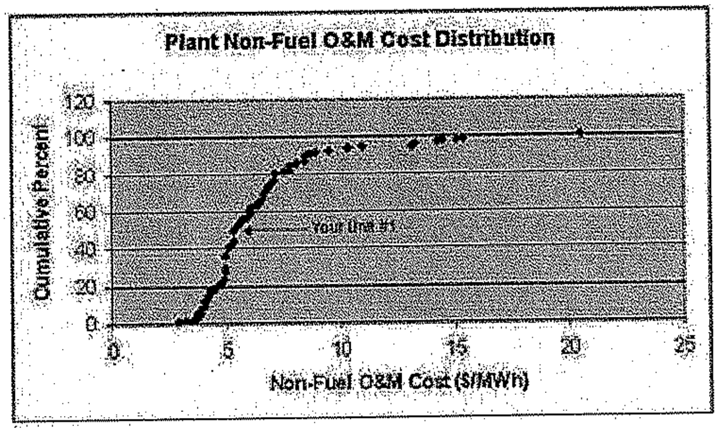
Fee Structure for Cost Benchmarking

Cost data normally comes as a cost per unit from various venders. The "per unit" data is a process of dividing the cost at a plant level by the MW capacity of the plant. This is an acceptable way of looking at costs if the units at the site are identical in all aspects of operation, size, fuels and others. That is not always the case. If a plant has a newer fossil unit and two old fossil units plus a gas turbine, the true cost per MW is not the same and should be treated at the same.

If cost benchmarking is required, it is best to more fully discuss the way the cost data would be used (on a plant or unit basis) before the cost for the work will be provided. This is a safe way for both GADS Services and the customer to know exactly what will be provided and how the cost data will be evaluated before work starts.

Setup Fee: If cost data is wanted, there is a $5,000 setup fee that covers the cost of preparing computer programs, purchase of cost information, phone consultation, and work forms used in the benchmarking process. It covers consultation for reviewing the fleet of units to be benchmarked and to divide the units into groups, if asked by the client.

Once the cost data is completed, graphs and tables can be produced. An example of the resulting graph is shown below:



Some of the standard cost graphs and tables available include:

- Plant Fuel Cost Distribution ($/MWh)
- Plant Non-fuel O&M Cost Distribution ($/MWh)
- Plant Non-fuel O&M Cost Distribution ($/kW)
- Plant Employee per MW Distribution
- Plant MWh per Employee Distribution

The cost for each set of five graphs for each peer group is $1000.

If additional graphs or tables are wanted, you can discuss the cost with a member of the Benchmarking Team.

Travel and Expenses

It is not required but recommended that the client and a member(s) of the NERC-GADS Benchmarking team meet to discuss the scope and approach before the work begins. It is also recommended that a meeting be scheduled to present the final results and discuss the findings. Traveling members of the NERC team would be compensated for their travel expenses plus $1200 per day for their time.

Final Report

NERC-GADS will provide a formal report on all results that will include:

1. Introduction
2. Overview of the process
3. Specific Results for each unit/group analyzed including a list of units in each peer group
4. Peer select Criterion for each of the client's units or group of similar units
5. Copy of Power Point slides discussing the NERC-GADS benchmarking process
6. Conference reports and research documents on NERC-GADS benchmarking work
7. CD-ROM and paper copy of the complete final report

Biography of the Benchmarking Team

G. Michael (Mike) Curley
Manager of GADS Services at the North American Electric Reliability Council (NERC) located in Princeton, New Jersey.

Shortly after graduating from college, Mike started working for the electric power industry, specializing in analyzing equipment failures and suggesting possible solutions to increase equipment and power unit productivity. He has worked for NERC since 1983 as a consultant in processing, analyzing and preparing both topical and specialized studies from the data collected by Generating Availability Data System (GADS). He has been involved in a number of NERC, Edison Electric Institute (EEI), American Society of Mechanical Engineers (ASME) and Electric Power Research Institute (EPRI) committees, and other industry and professional work groups.

Mike is a member of the World Energy Council's (WEC) Performance of Generating Plant (PGP) Committee. He is the chairman of two WEC-PGP working groups. Mike is a Fellow grade in the ASME. He is the author and co-author of more than a dozen technical papers.

Robert (Bob) R. Richwine
Reliability Management Consultant. As an independent consultant since 2002, Bob has consulted for numerous companies, including AES Energy (plant performance improvement), the International Atomic Energy Agency (inventory management), Tennessee Valley Authority (benchmarking), Mirant (reliability models and long term non-recurring cost estimating) and The National Grid Company of Ireland (benchmarking).

From 1976 to 1993 Bob was consulting reliability engineer at Southern Company Services in Birmingham , Alabama . After joining the firm Bob organized the company's Reliability Engineering group and progressed in increasing levels of responsibility until his departure for Southern Energy, Inc. in 1993. During these 17 years Bob was involved in the development and implementation of numerous programs and projects that have seen the southern electric system's coal-fired plant's availability increase from 68% in 1976 to over 92% by the late 1980's. Among these projects were the development and implementation of the company's Availability Improvement Program; Reliability, Availability, Maintainability (RAM) analysis; availability/reliability projections for existing/proposed power plants. Bob received The Southern Company Chairman's Excellence Award in 1995 and Southern Company Services President's Award in 1992.

In 1993 Bob moved to Southern Energy, Inc, Southern Company's unregulated arm, to head their Consulting Business unit. During his 9 years there he also provided Reliability Engineering support to SEI's (later Mirant) project development, trading and marketing and operations departments. In 2002 Bob left to pursue independent consulting.

Bob is a member of the World Energy Council's (WEC) Performance of Generating Plant (PGP) Committee and is the chairman of its Working Group on Workshops and Communications. In that capacity he publishes a monthly case study on various aspects of Reliability Engineering on the WEC website. Bob is also the author or co-author of over 30 technical publications on the subjects of Availability Improvement, Reliability Engineering, and cost/performance relationships for power plants.

Date-01/25/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

COMBINED CYCLE All MW Sizes 1999-2003 Data

1999-2003
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	NCF	SF	NOF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	SR	ART
1999	16.89	48.62	60.15	74.72	87.82	82.91	5.20	8.28	6.32	8.89	3.30	98.32	45.61
2000	15.64	54.68	69.32	73.86	89.72	84.21	3.62	7.77	6.36	7.67	2.61	98.65	61.49
2001	15.32	54.40	64.18	76.70	87.65	82.50	3.27	6.89	5.56	10.18	2.17	97.37	66.09
2002	13.61	48.08	57.26	73.91	89.32	85.54	3.47	7.10	5.27	8.63	2.06	96.29	49.17
2003	12.01	29.83	44.04	65.81	89.95	86.65	4.55	7.45	4.99	7.95	2.10	97.67	46.20
1999-03		44.76	57.35	72.79	89.00	84.65	4.00	7.48	5.57	8.61	2.39	97.56	52.31

		1999	2000	2001	2002	2003	1999-03
Unit-Years	:	70.00	63.67	69.17	94.25	107.00	404.08
Maximum Capacity (MW)	GROSS:	166	187	200	215	227	203
	NET:	161	180	195	209	221	197
Dependable Capacity (MW)	GROSS:	164	184	198	214	224	201
	NET:	158	178	193	208	219	195
Actual Generation (MWh)	GROSS:	712,337	897,956	970,147	910,694	595,532	801,048
	NET:	684,236	864,585	928,979	879,026	577,163	771,625
Attempted Unit Starts	:	117.51	100.30	87.40	105.81	85.36	98.41
Actual Unit Starts	:	115.54	98.95	85.10	101.88	83.37	96.01
Service Hours	:	5,269.40	6,084.38	5,623.95	5,009.69	3,851.37	5,022.43
Reserve Shutdown Hours	:	2,423.50	1,790.61	2,057.28	2,805.00	4,015.63	2,771.67
Number of Occurrences	:	64.00	61.38	77.25	73.22	72.86	70.35
Pumping Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Synchronous Condensing Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL AVAILABLE HOURS	:	7,692.74	7,874.86	7,681.33	7,814.73	7,867.01	7,794.08
Forced Outage Hours	:	288.97	228.64	190.06	180.14	183.73	209.28
Number of Occurrences	:	9.64	9.41	10.47	10.96	9.28	9.96
Planned Outages:							
Planned Outage Hours	:	526.74	517.13	561.15	401.17	505.55	496.22
Number of Occurrences	:	1.59	1.55	2.10	1.38	1.41	1.57
Planned Outage Ext. Hours	:	3.50	5.46	61.37	31.53	5.03	20.66
Number of Occurrences	:	0.01	0.05	0.04	0.15	0.04	0.06
Maintenance Outages:							
Maintenance Outage Hours	:	248.11	151.01	269.73	301.85	184.50	232.20

Number of Occurrences	:	4.51	4.71	5.41	4.64	4.18	4.64
Maintenance Outage Ext. Hours	:	0.00	0.00	0.00	20.36	0.10	4.78
Number of Occurrences	:	0.00	0.00	0.00	0.06	0.02	0.02
TOTAL UNAVAILABLE HOURS	:	1,067.34	902.15	1,082.24	935.02	878.83	963.09
TOTAL PERIOD HOURS	:	8,760.01	8,776.92	8,763.18	8,749.61	8,745.69	8,757.00
Equiv. Forced Hours	:	174.31	263.80	214.76	190.83	118.52	184.41
Equiv. Scheduled Hours	:	123.44	149.49	172.72	88.42	94.31	120.10
Equiv. Forced Hours During RS	:	36.98	20.76	58.23	31.88	20.91	32.62
Equiv. Seasonal Derated Hours	:	131.89	70.27	64.33	50.76	76.10	76.92
TOTAL EQUIVALENT DERATED HOURS	:	297.74	413.29	387.48	279.25	212.83	304.51

Treatment of PW Dispatch Benefits in PGE Filing

Example 1:

Assume that MONET runs with and without PW yield annual expected costs of 850 ($million) and 870 respectively, i.e. PW dispatch benefits are 20. Under the PGE construct, expected collections are 145 (= 1/6 * 870) in January-February and 705 (= 5/6 * 870 – 20) in March-December. Monthly collections are slightly higher in January and February because all PW dispatch benefits are applied only to the March-December period. However, expected costs for the year are 850, equal to the result from the MONET run with PW.

Next assume that forward curve electric prices increase, such that expected costs without PW increase to 894, but PW's dispatch benefits also increase to 44, i.e. higher electric prices increase the cost of the "phantom open position," by 24, but also increase PW dispatch benefits by the same amount. Then, under the PGE construct, expected collections are 149 (= 1/6 * 894) in January-February and 701 (= 5/6 * 894 – 44) in March-December. An increase in the cost of the "phantom open position" impacts January-February by +4 and March-December by +20. However, PW dispatch benefits impact March-December by -24, making the net March-December impact -4. The January-February and March-December impacts exactly off-set, leaving expected annual costs at 850.

Example 1 Calculation:

Base:	$ Million	
Base Annual Monet Run Without PW:	$870	
Base Annual Monet Run With PW March-December:	$850	Yearly Collections Should Be This Amount
Base PW Dispatch Benefits March-December:	$20	

	Jan-Feb.	Mar. - Dec.	Entire Year
Implied Shape of Collections:			
Base Annual Monet Run Without PW:	$145	$725	$870
Base PW Dispatch Benefits:		($20)	($20)
Total:	$145	$705	$850
Monthly Collections:	$72.50	$70.50	$70.83

If Forward Electric Curve Shifts Up:	$ Million	
Base Annual Monet Run Without PW:	$870	
New Annual Monet Run Without PW:	$894	
Added Cost Of "Phantom Open" Position:	$24	
New Annual Monet Run With PW March-December:	$850	Yearly Collections Should Be This Amount
New PW Dispatch Benefits March-December:	$44	

	Jan-Feb.	Mar. - Dec.	Entire Year
Implied Shape of Collections:			
New Monet Run Without PW:	$149	$745	$894
New PW Dispatch Benefits:		($44)	($44)
Total:	$149	$701	$850
Change From Base:	$4	($4)	$0
Monthly Collections:	$74.50	$70.10	$70.83

Example 2:

Work Papers 191-193 of PGE/200 demonstrate that PGE's initial filing includes rates which result in expected collections exactly equal to expected revenues. Work Paper 191 shows that expected collections are equal to expected net variable power costs (with PW available March 1, 2007), $847.3 million. This is comprised of $153.5 million in the January-February period (same as amount for those months on Work Paper 193, a without PW for the entire year look) and $693.8 million in the March-December period (same as amount for those months on Work Paper 192, a with PW look).[1] Implied rates are higher for the January-February period, but expected collections for the year are equal to expected costs for the year, $847.3 million. Note that Work Papers 191-193 are based on billing determinants, which track projected loads month-by-month. Since monthly loads vary, expected collections do as well, i.e. are not exactly 1/12 of expected annual collections.

Magnitude of Potential Effects:

a) The rate impact of PW, i.e. the difference between January-February and March-December rates, is approximately $0.60/MWh in the original filing.
b) In the initial filing, PW dispatches 158 MWa. The approximately one sixth of the "phantom open position" shift from March-December to January-February is then approximately 230,000 MWh (158 * 8760 / 6 = 230,680). Therefore, a $1/MWh shift in forward curves would shift approximately $230 k between periods, but not change overall test year expected collections. In the July 28 partial update, PW dispatches 203 MWa. A $1/MWh shift in forward curves would then shift approximately $296 k (203 / 158 * $230 = $296) between periods.
c) In summary, potential effects are small in the context of annual net variable power costs of approximately $850 million, and, again, do not change expected collections from customers on an annual basis.

[1] Work Paper 192 includes approximately 12/10 of the March-December PW dispatch benefits, as it is an annualized look at March-December net variable power costs with PW, necessary in the rate making process. Work Paper 191 only uses the March-December portion of Work Paper 192, or B in the terminology established in the theoretical discussion that follows.

Annual NVPC Revenues with March 1 Reregulation for Port Westward

Grouping	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Schedule 7	$38,893	$31,821	$29,241	$25,033	$23,208	$22,344	$24,447	$25,379	$22,227	$24,086	$29,866	$37,043	$333,589
Schedule 15	$106	$92	$86	$72	$63	$56	$60	$70	$79	$94	$100	$107	$984
Schedule 32	$6,079	$5,363	$5,573	$5,111	$5,140	$5,137	$5,708	$5,721	$5,200	$5,370	$5,360	$6,006	$65,768
Schedule 38													
On-peak	$89	$87	$94	$88	$89	$87	$88	$89	$87	$93	$94	$95	$1,080
Off-peak	$85	$81	$84	$77	$75	$73	$68	$69	$68	$69	$78	$87	$913
Schedule 47	$11	$15	$11	$18	$79	$119	$259	$259	$95	$30	$12	$10	$917
Schedule 49	$20	$33	$34	$60	$217	$387	$718	$753	$303	$94	$31	$21	$2,672
Schedule 83-S	$19,722	$18,436	$19,908	$18,423	$19,310	$19,507	$21,003	$20,689	$19,450	$20,327	$19,408	$20,407	$236,593
Schedule 89-S													
On-peak	$1,500	$1,388	$1,606	$1,506	$1,572	$1,609	$1,940	$1,997	$1,847	$1,843	$1,631	$1,605	$20,043
Off-peak	$693	$647	$719	$670	$695	$707	$851	$874	$831	$796	$719	$746	$8,949
Schedule 83-P	$1,000	$994	$1,055	$1,024	$1,024	$1,029	$1,114	$1,096	$1,064	$1,040	$996	$1,025	$12,461
Schedule 89-P	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
On-peak	$5,242	$5,062	$5,575	$5,396	$5,494	$5,598	$5,825	$5,866	$5,696	$5,491	$5,286	$5,432	$65,961
Off-peak	$3,054	$2,935	$3,152	$3,050	$3,111	$3,208	$3,268	$3,290	$3,226	$3,064	$3,034	$3,093	$37,484
Schedule 89-T													
On-peak	$3,057	$2,640	$2,823	$2,879	$2,870	$2,769	$2,909	$2,732	$2,766	$2,918	$2,767	$2,857	$33,985
Off-peak	$1,776	$1,724	$1,786	$1,815	$1,808	$1,814	$1,889	$1,714	$1,809	$1,826	$1,764	$1,798	$21,621
Schedule 91	$444	$385	$357	$294	$256	$225	$243	$291	$325	$393	$423	$455	$4,091
Schedule 92	$22	$21	$21	$21	$21	$21	$21	$21	$22	$21	$22	$21	$254
Schedule 93	$1	$1	$1	$2	$2	$3	$2	$2	$4	$4	$2	$1	$23
TOTAL	$81,793	$71,726	$72,126	$65,539	$65,034	$64,694	$70,413	$70,913	$65,097	$67,556	$71,592	$80,808	$847,290

$\underbrace{\text{Jan–Feb}}_{\$153.5m}$ $\underbrace{\text{Mar–Dec}}_{\$693.8m}$

$153.5
$693.8
$847.3

Annual NVPC Revenues with Port Westward

Grouping	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Schedule 7	$38,355	$31,381	$29,241	$25,033	$23,208	$22,344	$24,447	$25,379	$22,227	$24,086	$29,866	$37,043	$332,609
Schedule 15	$104	$91	$88	$72	$63	$56	$60	$70	$79	$94	$100	$107	$982
Schedule 32	$5,995	$5,289	$5,573	$5,111	$5,140	$5,137	$5,708	$5,721	$5,200	$5,370	$5,360	$6,006	$65,611
Schedule 38													
On-peak	$88	$86	$94	$88	$89	$87	$88	$89	$87	$93	$94	$95	$1,078
Off-peak	$83	$80	$84	$77	$75	$73	$68	$69	$68	$69	$78	$87	$911
Schedule 47	$11	$15	$11	$18	$79	$119	$259	$259	$95	$30	$12	$10	$917
Schedule 49	$20	$32	$34	$60	$217	$387	$718	$753	$303	$94	$31	$21	$2,671
Schedule 83-S	$19,452	$18,185	$19,908	$18,423	$19,310	$19,507	$21,003	$20,689	$19,450	$20,327	$19,408	$20,407	$236,070
Schedule 89-S													
On-peak	$1,480	$1,369	$1,606	$1,506	$1,572	$1,609	$1,940	$1,997	$1,847	$1,843	$1,631	$1,605	$20,004
Off-peak	$684	$638	$719	$670	$695	$707	$851	$874	$831	$796	$719	$746	$8,931
Schedule 83-P	$986	$980	$1,055	$1,024	$1,024	$1,029	$1,114	$1,096	$1,064	$1,040	$996	$1,025	$12,433
Schedule 89-P													
On-peak	$5,170	$4,992	$5,575	$5,396	$5,494	$5,598	$5,825	$5,866	$5,696	$5,491	$5,286	$5,432	$65,820
Off-peak	$3,012	$2,895	$3,152	$3,050	$3,111	$3,208	$3,268	$3,290	$3,226	$3,064	$3,034	$3,093	$37,402
Schedule 89-T													
On-peak	$3,014	$2,603	$2,823	$2,879	$2,870	$2,769	$2,909	$2,732	$2,766	$2,918	$2,767	$2,857	$33,907
Off-peak	$1,752	$1,701	$1,786	$1,815	$1,808	$1,814	$1,889	$1,714	$1,809	$1,826	$1,764	$1,798	$21,474
Schedule 91	$438	$380	$357	$294	$256	$225	$243	$291	$325	$393	$423	$455	$4,080
Schedule 92	$21	$21	$21	$21	$21	$21	$21	$21	$22	$21	$22	$21	$253
Schedule 93	$1	$1	$1	$2	$2	$3	$2	$2	$4	$4	$2	$1	$23
TOTAL	$80,666	$70,738	$72,126	$65,539	$65,034	$64,694	$70,413	$70,913	$65,097	$67,556	$71,592	$80,808	$845,175

$\underbrace{\text{Mar–Dec totals}}_{\$693.8m}$

Annual NVPC Revenues without Port Westward

Grouping	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Schedule 7	$38,893	$31,821	$29,652	$25,385	$23,533	$22,657	$24,790	$25,735	$22,539	$24,424	$30,286	$37,563	$337,279
Schedule 15	$106	$92	$87	$73	$64	$57	$61	$71	$80	$95	$102	$109	$995
Schedule 32	$6,079	$5,363	$5,651	$5,183	$5,212	$5,209	$5,788	$5,801	$5,272	$5,445	$5,435	$6,090	$66,528
Schedule 38													
On-peak	$89	$87	$96	$89	$90	$88	$89	$90	$88	$94	$95	$97	$1,093
Off-peak	$65	$81	$85	$78	$77	$74	$69	$70	$69	$70	$79	$88	$924
Schedule 47	$11	$15	$11	$18	$80	$120	$262	$263	$96	$30	$12	$10	$929
Schedule 49	$20	$33	$34	$61	$220	$392	$728	$764	$308	$95	$31	$21	$2,708
Schedule 83-S	$19,722	$18,436	$20,185	$18,679	$19,579	$19,779	$21,295	$20,977	$19,721	$20,610	$19,678	$20,690	$239,352
Schedule 89-S													
On-peak	$1,500	$1,388	$1,628	$1,527	$1,594	$1,631	$1,867	$2,024	$1,872	$1,866	$1,653	$1,627	$20,280
Off-peak	$693	$647	$729	$679	$705	$717	$863	$887	$843	$807	$730	$757	$9,056
Schedule 83-P	$1,000	$994	$1,069	$1,038	$1,039	$1,043	$1,130	$1,111	$1,079	$1,065	$1,010	$1,039	$12,607
Schedule 89-P													
On-peak	$5,242	$5,062	$5,652	$5,470	$5,570	$5,675	$5,905	$5,948	$5,775	$5,567	$5,359	$5,507	$66,732
Off-peak	$3,054	$2,935	$3,196	$3,093	$3,154	$3,253	$3,314	$3,336	$3,271	$3,107	$3,076	$3,136	$37,923
Schedule 89-T													
On-peak	$3,057	$2,640	$2,863	$2,919	$2,910	$2,808	$2,950	$2,770	$2,805	$2,959	$2,806	$2,897	$34,383
Off-peak	$1,776	$1,724	$1,810	$1,840	$1,832	$1,838	$1,914	$1,737	$1,833	$1,851	$1,766	$1,823	$21,766
Schedule 91	$444	$385	$362	$298	$260	$228	$247	$295	$330	$398	$429	$461	$4,137
Schedule 92	$22	$21	$21	$22	$21	$21	$21	$21	$22	$21	$22	$21	$257
Schedule 93	$1	$1	$1	$2	$2	$3	$2	$2	$4	$4	$2	$1	$24
TOTAL	$81,793	$71,726	$73,133	$66,454	$65,941	$65,597	$71,395	$71,902	$66,005	$68,498	$72,591	$81,937	$856,973

$153.5 m

2007 COS Billing Determinants

Grouping	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Schedule 7	868,538	710,617	662,170	566,881	525,534	505,971	553,604	574,704	503,320	545,416	676,322	838,840	7,531,917
Schedule 15	2,498	2,178	2,053	1,714	1,510	1,345	1,434	1,688	1,885	2,242	2,399	2,563	23,509
Schedule 32	137,432	121,262	127,761	117,174	117,846	117,767	130,867	131,159	119,206	123,103	122,884	137,682	1,504,143
Schedule 38													
On-peak	1,846	1,815	1,987	1,861	1,869	1,831	1,858	1,880	1,838	1,963	1,981	2,012	22,740
Off-peak	2,063	1,971	2,067	1,911	1,868	1,818	1,682	1,698	1,678	1,716	1,924	2,149	22,545
Schedule 47	280	369	268	446	1,981	2,994	6,527	6,543	2,397	755	290	259	23,110
Schedule 49	512	816	860	1,532	5,516	9,819	18,220	19,113	7,696	2,383	782	521	67,770
Schedule 83-S	450,797	421,438	461,377	426,944	447,509	452,083	486,750	479,470	450,757	471,075	449,787	472,922	5,470,909
Schedule 89-S													
On-peak	32,403	29,971	35,169	32,973	34,425	35,232	42,476	43,720	40,438	40,351	35,703	35,148	438,009
Off-peak	17,673	16,476	18,574	17,315	17,957	18,278	21,985	22,594	21,484	20,561	18,591	19,286	230,772
Schedule 83-P	23,712	23,562	25,358	24,624	24,627	24,738	26,790	26,350	25,584	25,008	23,960	24,639	298,952
Schedule 89-P													
On-peak	117,425	113,387	126,614	122,544	124,772	127,137	132,287	133,236	129,360	124,716	120,058	123,362	1,494,896
Off-peak	80,775	77,627	84,521	81,796	83,422	86,039	87,637	88,237	86,499	82,161	81,349	82,937	1,003,001
Schedule 89-T													
On-peak	69,407	59,940	65,012	66,281	66,072	63,763	66,974	62,901	63,692	67,180	63,705	65,789	780,717
Off-peak	47,692	46,302	48,628	49,415	49,217	49,381	51,422	46,653	49,246	49,706	48,015	48,956	584,632
Schedule 91	10,459	9,069	8,525	7,027	6,125	5,378	5,810	6,941	7,761	9,376	10,103	10,864	97,437
Schedule 92	502	496	494	501	494	494	486	487	507	482	506	492	5,939
Schedule 93	24	23	31	36	49	73	50	47	86	85	37	25	565
TOTAL	1,864,034	1,637,320	1,671,467	1,520,975	1,510,793	1,504,141	1,636,858	1,647,419	1,513,433	1,568,279	1,658,396	1,868,446	19,601,562
Ratio	9.51%	8.35%	8.53%	7.76%	7.71%	7.67%	8.35%	8.40%	7.72%	8.00%	8.46%	9.53%	

January-February Ratio	17.863%
March-December Ratio	82.137%

<u>Theoretical Approach:</u>

<u>Terminology:</u>

Use that in Exhibit CUB/100, Pages 8-10:

A = NVPC in January-February period (includes largely filled position for portion of load that will be covered by PW beginning March 2007)

B = NVPC in March-December period with PW (includes dispatch benefits of PW over this period)

C = NVPC in March-December period without PW (leaves position open that will, in reality, be covered by PW operation)

<u>Are rates designed to collect the expected NVPC?</u>

As noted on Page 9 of CUB/100, expected NVPC for 2007 are the sum of A and B. The rates PGE submitted in its filing will collect (A + B). Abstracting from the fact that loads vary across months, the general principle is the following:

During the January-February period, PGE's rates will be based on a MONET run without PW, or annual costs equal to the sum of A and C. January-February collections then are expected to be (1/6) * (A + C).

During the March-December period, PGE's rates will be based on a MONET run with PW available from March-December. Costs for this ten-month period can conceptually be decomposed into 5/6 of the "without PW" costs, minus the dispatch benefits of PW. Specifically, this is (5/6) * (A + C), plus the dispatch benefits (or negative costs) of PW, (B – C). Then rates are constructed so that March-December collections are expected to be [(5/6) * (A + C) + (B – C)]. Therefore expected collections for the year are (1/6) * (A + C) + (5/6) * (A + C) + (B – C), or (A + C) + (B – C), which is equal to (A + B). This demonstrates that rates are designed to collect the expected NVPC.

Notes: (B – C) cannot be positive, and will be negative if PW dispatches at all, as noted on Page 9 of CUB/100. The idea that customers will likely be charged more than expected costs is, however, not correct. If (1/6) of the dispatch benefits of PW, i.e. (1/6) * (B – C,) were transferred from the March-December period to the January-February period, expected collections in the January-February period would be (1/6) * (A + C) + (1/6) * (B – C), or (1/6) * (A+B). However, expected collections in the March-December period would be (5/6) * (A + C) + (B – C) – (1/6) * (B – C), or (5/6) * (A+C) + (5/6) * (B – C), which equals (5/6) * (A + B). Then expected annual collections would be (1/6) * (A + B) + (5/6) * (A + B), or (A + B). Any change of (1/6) * (B – C) in PGE's construct during the January-February period is off-set by a change of equal magnitude, but opposite sign, in the March-December period.

<u>Are customers subject to increased volatility?</u>

Under PGE's construct, expected collections in January-February are (1/6) * (A + C), and C includes an unfilled position equal to the expected output of PW. The cost of this open position changes with updates to the forward curves during the series of MONET runs leading up to final rate setting. Therefore, (1/6) * (A + C) is subject to volatility within the "2007 MONET without PW" context. One sixth of the "phantom open position," but none of the hedging power of PW, impact the January-February period.

However, this is exactly offset in the March-December period. Expected collections in this ten-month period can again be decomposed into (5/6) * (A + C) and (B-C). This translates into the volatility from five sixths of the "2007 MONET without PW" open position, plus <u>all</u> of the hedging power of PW. The shortage of hedging power in the January-February is exactly off-set by "extra" hedging power in the March-December period.

Considering the 2007 year as a whole, customers receive all of the dispatch benefits of PW, which exactly hedges, or fills in, the "phantom open position" in the MONET run without PW. In other words, PGE's construct neither increases, nor decreases, volatility for customers.

Portland General Electric Company
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Richard George
Assistant General Counsel

March 23, 2006

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
PO Box 2148
Salem OR 97308-2148

Re: In the Matter of PORTLAND GENERAL ELECTRIC 2006 Integrated Resource Plan
OPUC Docket No. LC 33

Attention Filing Center:

In its Order No. 05-1138 in the above-captioned docket, dated October 20, 2005, the Commission asked that Portland General Electric ("PGE") provide the Commission with an action plan update by March 31, 2006.

Enclosed are two documents that PGE is presenting before the Commission today:

- "Portland General Electric 2002 Integrated Resource Plan Final Action Plan Update," March 23, 2006; and
- "Action Plan Update: PGE's 2002 IRP Final Action Plan," Power Point Presentation, March 23, 2006.

Please file these documents in the above-captioned docket. These documents are being filed by electronic mail with the Filing Center.

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

Thank you in advance for your assistance.

Sincerely,

J. Richard George

JRG:am

cc: LC 33 Service List

Enclosure

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing ACTION PLAN UPDATE AND POWER POINT PRESENTATION OF PORTLAND GENERAL ELECTRIC COMPANY to be served by First Class US Mail, postage prepaid and properly addressed, and by electronic mail, upon each party on the attached service list in OPUC Docket LC 33.

Dated at Portland, Oregon, this 23rd day of March, 2006.

/s/ J. RICHARD GEORGE
J. Richard George

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Portland General Electric
2002 Integrated Resource Plan
Final Action Plan Update

Portland General Electric

March 23, 2006

Table of Contents

Executive Summary

In accordance with Order 89-507 investor owned utilities (IOUs) are required to file with the Oregon Public Utility Commission (OPUC or the Commission) an Integrated Resource Plan (IRP) that delineates the forecasted retail load requirements of their respective customers and the energy and capacity portfolio resources necessary to meet such requirements. On August 9, 2002, PGE filed its most recent IRP and on March 26, 2004, we filed an IRP Final Action Plan that listed base-case resource actions that PGE would pursue to meet the forecasted resource deficit between retail loads and then current power supply portfolio resources. This 2002 IRP Final Action Plan (Final Action Plan) was acknowledged by the OPUC on July 20, 2004.

The primary purpose of this report is to outline the progress that PGE has made towards achieving the targeted resource actions under our Final Action Plan. The second half of the report provides a primer into the research and processes that PGE is pursuing in support of our 2006 IRP, which we intend to file in December 2006.

PGE is pleased to report that it has achieved all of the energy and capacity resource targets in our acknowledged Final Action Plan except for an additional 38 MWa of wind energy, for which negotiations are proceeding. We are also pleased to report that once we complete our current wind energy negotiations, PGE will have in all material respects achieved all of the resource actions from our Final Action Plan.

On the energy supply side of the Final Action Plan, these actions include implementation of a long-term wind purchase, execution of mid-to-long-term power contracts, energy efficiency programs implemented by the Energy Trust of Oregon (ETO), efficiency upgrades at existing PGE generating facilities and construction of the Port Westward natural gas combined-cycle generating plant.

With respect to capacity, PGE has acquired additional peaking resources above and beyond the capacity acquired with our energy actions. These additional capacity actions include an expansion of our Dispatchable Standby Generation program at customer sites and purchasing winter peaking contracts from other energy market participants.

Equally important is PGE's pursuit of demand response opportunities through our various programs, including Demand Buy-Back, Energy Information Services, Time-of-Use pricing, load curtailment contracts,

residential direct load control, Advanced Metering Infrastructure and real-time pricing. PGE is also participating in the GridWise™ testbed, specifically researching non-wires solutions to reducing peak capacity. In addition, PGE continues to support the ETO in its development of energy efficiency initiatives.

At the same time we have taken several steps to respond to the other IRP requirements from the Commission's acknowledgement order related to transmission and new resource procurement. PGE completed a Master Funding Agreement with the ETO for the purpose of accessing ETO funds to reduce the cost of above market priced renewables to that of alternative energy opportunities. Also in support of renewables, we participated in a joint letter to Oregon's federal delegation regarding renewal of the IRS Section 45 Production Tax Credit (PTC).

In the area of transmission, PGE has actively participated in several Bonneville Power Administration (BPA) and regional forums and initiatives to explore ways to increase transmission availability across the Cascades. In some cases these efforts have resulted in new BPA business practices and increased transmission capacity. PGE has also taken steps to retain existing transmission rights to protect the reliability interests of our customers.

In preparation for our 2006 IRP filing, PGE is conducting several studies to increase our level of knowledge, analysis and dialogue regarding future resource needs and choices. The studies range in topic from coal plant technology to carbon sequestration, and from load-resource balance and reserve margin requirement to wind integration. We also conducted two surveys with our residential, business and our largest customers to determine their preferences regarding price, risk and other resource choice attributes.

At the encouragement of the OPUC and to improve the robustness of our power supply portfolio analysis, we undertook an extensive evaluation of various third party power supply portfolio modeling tools. This process resulted in the selection of the EPIS Aurora^{xmp}® model. This model will help to enhance our economic and risk assessment related to future resource decision-making. We are currently in the process of implementing the model and expect to present results later in the public process.

As we reflect on the activities to date in support of PGE's Final Action Plan, we are pleased that we have been able to substantially meet our targeted resource actions. We also remain optimistic about our ability to complete the remaining resource acquisitions, while continuing to proactively respond to the Commission's acknowledgement order.

At the same time, we recognize that the risks and environment that we face in meeting our customers' ongoing electricity needs continue to evolve. Wholesale energy market conditions, regional resource initiatives, local and national legislation and changing constituent preferences, as well as many other factors, must all be considered as we move forward. With this in mind we embark on concluding the final elements of our Final Action Plan and prepare for PGE's 2006 Integrated Resource Plan.

Introduction

Since the OPUC acknowledged our Final Action Plan in July 2004, PGE has been actively working to complete the remaining resource actions and related initiatives from the acknowledgement order. As of March 2006, we are pleased to announce that we have acquired all of the resources included in our Final Action Plan, except for an additional 38 MWa of wind energy.

We are continuing negotiations with two wind bidders from our 2003 RFP, which we anticipate to conclude shortly. We also continue to work toward addressing the demand-side and transmission issues identified in our Final Action Plan and the Commission's acknowledgement order.

The objective of this document is to provide an update regarding the actions that PGE has taken to meet the resource targets identified in our Final Action Plan. We also provide an outline of the proposed activities and schedule for our 2006 IRP, which we expect to file by the end of this year.

The following table summarizes our energy and capacity actions to date.

Energy Portfolio Actions	2002 IRP Action Plan		Resource Acquired to Date	
	2007 MWa	2007 MW	MWa	MW
Short-term Acquisitions[1]	125	125	125	125
Plant Upgrades	41	50	36	41
Other Operating Changes[2]	5	0	5	0
Hydro Contract Extension[3]	14	116	14	116
EE per the Energy Trust of Oregon[4]	55	79	34	49
Fixed Price PPAs	135	150	132	150
Wind (assumes capacity value = energy)[5]	65	65	27	27
Port Westward	350	375	360	382
Total Energy Actions	790	960	733	890
Additional Capacity Actions				
Dispatchable Standby Generation		30		45
Port Westard Duct Firing		25		25
Peak Tolling from Bids		400		400
Fill-in Short-Term from the Market[1]		500		500
Total Additional Capacity Actions		955		970

[1] Purchased as needed to balance resources to load.
[2] Represents PGE's expectation of ongoing operation of the Bull Run hydro project.
[3] 2002 IRP Target included an additional 49 MWa of energy at market index price, which is included here in the 125 MWa of short-term acquisitions. Total energy from hydro contract extension is 63 MWa.
[4] ETO target of 55 MWa is for acquisitions through 12/31/2007; 34 MWa acquired is for 2004 and 2005. MW savings are estimates based on implied load factors.
[5] PGE is continuing negotiations with two wind bidders to acquire the remaining 38 MWa.

Supply-Side Updates

Wind

PGE's Final Action Plan includes as an action item the acquisition of approximately 65MWa (195 MW) of wind generation, provided that the necessary transmission and integration services can be obtained, and ETO funds permit a price within the range of other alternatives. As described below, PGE has acquired 42 percent of its targeted wind generation and is actively negotiating with two counterparties to acquire additional generation to meet its target.

Klondike II Wind Farm

In December 2004 PGE executed a power purchase agreement (PPA) with PPM Energy, Inc. (PPM) for the acquisition of 100% of the generation output of the Klondike II Wind Farm located in Sherman County Oregon. The expected output of this facility is 27 MWa on an annual basis. In August of 2005 construction of this wind farm was substantially completed and the facility was synchronized to the transmission grid. Effective December 1, 2005, PGE began taking delivery of the entire output of this wind farm subject to an energy firming and shaping service provided by PPM.

The Klondike II purchase meets about 42 percent of the wind resources targeted in our Final Action Plan, based on the expected average energy. Wind in the Klondike area is generally thermally driven, which increases energy production in the late spring and summer and in the late afternoon when PGE's summer peak energy needs are higher.

Wind Actions to be Completed

PGE is actively working to complete negotiations with wind bidders to acquire the remaining 38 MWa (100 to 125 MW) of wind energy. These negotiations have been complicated by price increases in steel, concrete and other building materials, in addition to wind turbine generators. PGE is hopeful that it will be able to complete these negotiations and capture the IRS Section 45 Production Tax Credit benefit (PTC) prior to its expiration on December 31, 2007.

Final project selection will be based on pricing and terms at the time of execution. Timeliness for completing negotiations will also be a factor.

PGE will not know whether these wind proposals will require an ETO subsidy for any above-market costs until negotiations are concluded.

Port Westward

PGE's acknowledged Final Action Plan includes an action item to build or acquire 350 MWa of high efficiency gas-fired resource. Construction is well underway on PGE's new Port Westward natural gas-fired combined-cycle power plant. The project is located near Clatskanie, Oregon and adjacent to the existing PGE Beaver natural gas-fired power plant.

Once complete, the Port Westward plant is expected to be the most efficient natural gas-fired generator of its type in the Northwest region of the United States, with a heat rate of 6,826 Btu/kWh (HHV). The target completion date is March 2007, with a guaranteed substantial completion date of May 2007. The project is currently on time and within budget. As of February 28, 2006:

- Engineering was over 83 percent complete.
- Procurement was 86 percent complete.
- Construction was over 37 percent complete.

The new plant will yield 407 MW of capacity at average temperature and conditions, including 382 MW base-load plus 25 MW duct firing. Average available energy from Port Westward will be 360 MWa.

The site selection process took advantage of existing electrical transmission and natural gas transportation infrastructure. Construction of a transmission line from the Port Westward site to PGE's decommissioned Trojan site will allow for delivery of power directly into PGE's grid, avoiding connecting to BPA's system and the related transmission and ancillary services fees. Transmission line losses will also be lower, resulting in reduced costs. In combination, the avoided third-party transmission fees and line losses result in a significant cost savings for PGE customers.

To provide more fuel reliability and price stability, PGE contracted with NW Natural Gas for a 10-year firm interstate gas storage service agreement under which we will be able to store up to 1.26 million dekatherms of natural gas in the Mist gas storage facility near the Port Westward site. We will use the stored gas to augment gas pipeline service to our Beaver and Port Westward plants. Using local natural gas storage facilities allows PGE to reduce fueling costs while maintaining the reliability of the Port Westward and Beaver plants.

PGE also holds 57,000 dekatherms per day of Sumas capacity and 30,000 dekatherms per day of Rockies capacity for a total of 87,000 dekatherms per day of gas pipeline capacity. This allows PGE to fully supply Port Westward's base-load and peaking operations, and to supply Beaver with sufficient transport and storage capacity to meet its expected dispatch and fueling needs.

Plant Efficiency Upgrades

In its Final Action Plan PGE identified as existing actions a number of plant improvements. We have since completed upgrades to our Beaver, Boardman and Faraday plants, for an additional 36 MWa of energy and 41 MW of capacity. These results are slightly short of our Final Action Plan target of 41 MWa and 50 MW, which was based on engineering estimates at that time.

For Beaver and Boardman, the new efficiency ratings require no additional fuel and result in no increase in plant emissions. For Faraday, the improvements will allow us to realize more energy production without requiring extra water to pass through the turbines. The upgrades are:

- Faraday – 4.3 percent increase in output, 1 MWa.
- Beaver – 2.1 percent, 18 MWa.
- Boardman – 1.8 percent, 17 MWa.

Contract Renewals

PGE also listed as a completed action item in its Final Action Plan the renewal of our contract with the Confederated Tribes of Warm Springs for the output of their share of the Pelton-Round Butte hydro-generation projects and the Pelton re-regulating dam. These contracts add 65 MWa of energy and 161 MW of capacity from January 2007 through February 2012, versus estimated Final Action Plan targets of 63 MWa and 165 MW. Of the 65 MWa, 14 MWa is received at a fixed price, with the remainder being received at a market index price.

Power Purchase Agreements for Energy

Our Final Action Plan included as an acknowledged action item the acquisition of 135 MWa in fixed price PPAs for durations of five to ten years. As described below, PGE has acquired 132 MWa in PPAs.

We executed a 10-year, 100 MW fixed-price PPA. Under this agreement PGE receives energy according to actual production at the power plant. Based on expected plant availability, we anticipate receiving about 93 MWa of energy over the contract term. We also executed two contracts for system power, including a five-year fixed price PPA for 25 MWa, along with a 25 MW base-load tolling agreement, which we expect will provide 14 MWa of energy.

Capacity Contracts

In the Final Action Plan PGE included 400 MW of peak tolling agreements. PGE has now completed this action item by executing two contracts totaling 400 MW of peak system tolling to meet winter peak load demands. Both capacity contracts are natural gas peak tolling arrangements, whereby PGE has the right to receive power based on a pre-determined plant heat rate and a regional market price for gas.

One of the contracts is for up to 300 MW available during the winter months from 2006 through April 2011. The other contract for 100 MW is available for peak winter months beginning in December 2005 and ending in 2010.

Customer Sited Combined Heat and Power

As part of our Final Action Plan, we committed to evaluate the market potential for combined heat and power (CHP) systems at customer sites. The following summarizes PGE's activities and findings in this area to date.

Increased market penetration by CHP can potentially produce economic benefits, energy savings, and reductions in pollutants such as NOx and CO_2 in the region. From a generation host perspective, CHP can provide heat or steam for onsite processes, and also meet all or part of the host's onsite power needs. However, for CHP to be cost-effective and energy efficient, it must be used in applications that have highly coincidental electric and thermal loads and have electric-to-thermal demand ratios in the 0.5 to 2.5 range. Scale of the resource and thermal load also has a significant effect on cost.

PGE continues to work with the industrial candidates in our service territory to evaluate potential combined heat and power projects. Following acknowledgement of our Final Action Plan, PGE also commissioned a study by an independent consultant to assess the technical and economic market potential for customer sited CHP in the commercial and institutional sectors. The study showed that larger applications in markets like hospitals and universities offer the best technical viability and economics for using CHP. These industries have access to relatively low cost capital, as well as the necessary staff levels to maintain and operate a CHP system.

Other industries that appear to offer good economic potential such as nursing homes and prisons may be disadvantaged in the areas of O&M staff and access to capital, and also view investing in and operating CHP systems as distant from their core business. Other barriers to CHP include environmental and siting regulations.

PGE is an active member of the Combined Heat and Power Consortium hosted by NW Natural Gas. Through the Consortium, PGE has worked with two local hospitals and a university to develop combined heat and power projects, although no projects have yet been implemented.

At the same time, PGE continues to proactively participate in OPUC proceedings that are related to or influence the development of CHP resources. In particular, the current UM-1129 docket and the Partial Requirements rate schedules resulting from the UE-158 process provide additional clarity with respect to important issues affecting CHP.

One of the goals of phase one of the currently open UM-1129 Qualifying Facility (QF) docket is to establish a standard contract and framework for Oregon electric utilities to purchase power from QFs that are less than 10 MW in size. Phase two of this docket addresses contract terms and conditions for larger (greater than 10 MW) QFs.

Following issuance of the Final Action Plan, PGE worked with interested parties to develop a series of Partial Requirements schedules for customers with on-site generation. These schedules were developed in connection with the UE-158 investigation and in cooperation with various stakeholders including OPUC Staff, Industrial Customers of Northwest Utilities, Oregon Department of Energy, and select customers. Schedules 75 and 76R are for customers receiving their energy supply from PGE.

The Partial Requirements rate schedules provide consumers who have on-site generation with a reasonable set of charges and options for utilization of the PGE system. The schedules also provide that other consumers on the PGE system are reasonably assured that the Partial Requirements consumer is not placing unjustified burdens and costs on the system. Finally, the Partial Requirements schedules support an objective of the Commission to remove barriers to the development of distributed generation.

We continue to evaluate these issues, participate in local and regional forums, and maintain an open dialogue with customers and interested parties with respect to CHP. By doing so, we hope to increase our awareness and understanding of the market potential, assess ways to overcome barriers and seek technically viable and cost-effective CHP opportunities to help meet our future resource needs.

Dispatchable Standby Generation

In the 2002 IRP we listed Dispatchable Standby Generation (DSG) as one of our capacity resources.[1] As part of our acknowledged action items, we committed to developing a 30 MW "virtual peaking plant" by the winter of 2006-07. By the end of 2005 we had 29 MW on line and available for dispatch. We have another 16 MW signed or under construction, for a total of 45 MW of dispatchable standby generation available by the end of 2007.

We have found that customer enthusiasm and adoption rates for this program have been higher than we originally anticipated. The high levels of customer interest and participation have allowed PGE to establish one of the most successful customer-based capacity programs of its kind. This option, because of its distributed nature, also provides reliability benefits for PGE and the host customers.

DSG is a high quality, cost-effective capacity resource that also serves as reserve capacity. The projects pursued were either new installations or major rehabilitations that represented lost opportunities if the construction window was missed.

Since we have received inquiries and further interest from customers beyond our current implementation, we believe that the DSG program could potentially be expanded to help meet more of PGE's future capacity needs. Ultimately, we may be able to develop as much as 100 MW, depending on future economics and customer adoption rates.

Because this resource relies on the operation of diesel-fueled, back-up generators at non-residential customer sites, we are limited in the number of hours per year that we can operate each plant. However, this limitation does not impair the effectiveness of DSG as a capacity option,

[1] See Appendix K, p. 179.

as we only intend to dispatch the resource during infrequent super-peak events and to meet PGE and customer reliability needs.

Energy Trust of Oregon Master Service Agreement

In 2005 PGE executed a Master Funding Agreement with the ETO that will expedite our acquisition of future renewables projects. The agreement designated ETO funds to assist PGE in acquiring new renewable energy resources by subsidizing any above-market costs. The agreement also outlines all key terms and conditions for requesting, securing and administering subsidy funds for such projects.

Joint Letter to Oregon's Delegation

We participated in a joint letter to Oregon's federal congressional delegation urging the renewal of the PTC for renewables. Both U.S. Senators voted for the subsequent extension. The other co-signers included: Puget Sound Energy; PacifiCorp; NorthWestern Corporation; Citizens' Utility Board of Oregon; and the Washington State Office of Community, Trade and Economic Development (see appendix).

We joined the Legislative Committee of the American Wind Energy Association (AWEA) in early 2005 and worked with them and other members to secure PTC extension. We also visited our Congressional delegation on the Ways and Means Committee twice in Washington, D.C. to discuss these issues.

Demand-Side Updates

PGE's Final Action Plan included as an action item the acquisition of capacity through customer demand reduction programs. As described more fully below, PGE has a number of such programs underway. PGE also continues to assess the development of demand response options within its service territory and to monitor demand-side initiatives regionally and nationally.

Demand Buy-Back Program

We offer large, non-residential customers our Demand Buy-Back (DBB) program, which can be implemented during critical peak hours. Because DBB is a voluntary program with responsiveness at the discretion of participating customers, we do not consider it to be a firm capacity resource. However, depending on customer responsiveness, it should help reduce our capacity needs during the highest price peak hours.

The program typically is triggered under 1-in-5 peak load conditions, and has been effective in the past for reducing peak demand, where savings offered by PGE were also high enough to attract customer participation. While agreeing to provide over 25 MW of capacity reductions, our customers tell us that their responsiveness depends on a variety of business and operating conditions, in addition to the curtailment payments offered by PGE.

Given these factors, few customers have expressed a willingness to enter into firm, non-discretionary arrangements. Based on our interviews with customers, we determined that PGE can count on approximately 3 to 3.5 MW of capacity at any time for resource planning purposes through the DBB program.

Energy Information Service

All Schedule 83 customers with greater than 30 kW of demand are eligible for PGE's Energy Information Services (EIS). By knowing when peaks occur, customers can analyze their processes and respond accordingly. In some instances, this information has helped customers know which processes they can alter or shift to reduce peaks, or to participate in PGE demand response programs. EIS can also be used to track the effects of energy efficiency initiatives.

Approximately 90 customers, representing about 540 meters, are currently signed up for the service. This is a small percentage of our 8,000 business customers with loads above 30 kW, and about 14 percent of our 630 top- and mid-tier customers with loads over 500 kW.

Time-of-Use Pricing Option

Beside load control programs, we offer a time-of-use pricing option to residential customers. A relatively low number of customers, about 1,800, are currently enrolled in the program. While participation has been limited, the customers in the program report that they are pleased with the option. Though not economic on a total resource cost basis today, time varying rates may become more viable in the future.

Our time-of-use evaluation study, revised in 2004, shows the average winter peak load shift to be about 0.2 kW per node. With 1,800 customers enrolled in time-of-use, the total capacity reduction is minimal. With our relatively low regional system cost, marketing efforts to further increase enrollment would have an adverse economic effect because promotion costs would exceed the avoided cost savings.

Load Curtailment Contracts

We also offer large, non-residential customers customized contracts for load curtailments under peak conditions. Because these contracts require mandatory curtailments, we consider executed contracts to be a firm resource.

Load curtailment contracts are customized to give our large customers the opportunity to help design the structure that would be the best fit for their operations for reducing load during peak demand periods.

The negotiated pricing for these contracts is based on our market rates and the cost of avoided capacity at the time. Since we filed our Final Action Plan, we sent invitations to the 70 most likely customers that might participate in our load control program, based on their size and the nature of their business operations. So far, one customer has shown interest but a contract was not negotiated.

We continue to monitor the key cost drivers and explore load curtailment contracts with our customers as an alternative to supply-side capacity acquisitions.

Residential Direct Load Control

PGE has conducted pilot programs for direct load control of space and water heating load. The results show that neither is yet an economic capacity resource given PGE's prices, resource characteristics and cost structure.

Load control programs appear to be more economic in warmer regions of the country. For example, PacifiCorp and Comverge state that their load control contract is economic in Utah. Also, Florida Power & Light indicates that their load control program is cost-effective. At the same time, some Southern California IOUs have said that their load control programs are not yet cost-effective, but they run the programs at the State's direction.

Such programs control residential air conditioning and pumping for irrigation, and reduce summer peaking in areas that are constrained in the summer. Summer air conditioning tends to be a season-long event, compared with short and limited durations for winter space heat control. Longer durations allow the programs to overcome the initial investment hurdle and the ongoing program costs.

The peak capacity resources for these summer peaking utilities are typically more expensive. In addition, summer peaking utilities do not enjoy the low-cost hydro flexibility that is largely unique to the Pacific Northwest. As a result, cooling demand-based load control programs tend to be more cost effective in other regions, as they typically displace higher cost peaking resources and the peaking needs they address are more frequent. PGE continues to advance our work in this area.

Advanced Metering Infrastructure Update

PGE is currently evaluating a proposed Advanced Metering Infrastructure (AMI) system that would provide the necessary technology and systems to allow PGE to add the capability to offer a sophisticated demand-side program. An AMI system would enable PGE to offer more advanced pricing and load control options.

A report issued by the U.S. Department of Energy recently recommended adopting enabling technologies, including automated metering, as a means of encouraging the growth of demand response.[2]

If AMI is implemented, some of the demand-response benefits will not be recognized immediately and some will require additional investment. For example, the proposed AMI system will allow us to offer smart appliance services, but not until our customers purchase smart appliances. Other functions for these programs will be developed in the future. PGE has requested OPUC approval of its AMI system.

Real-Time Pricing Pilot

Schedule 87 for customers with loads of one MW and above is our real-time pricing pilot. The pilot is intended to reduce demand by focusing on load curtailments when prices are high. Participating non-residential customers receive day-ahead notification of hourly prices, giving them the opportunity to reduce peak loads, or to shift loads to less expensive off-peak hours.

The pilot results demonstrated that while some customers expressed interest in the option, none have signed up to participate. Reasons for this may include the availability of other PGE DSM programs and apprehension about market price exposure, as well as customer hesitancy to disrupt or alter their business operations. Schedule 87 customers cannot concurrently participate in PGE's Demand Buy Back, Dispatchable Standby Generation, or any of our market-based options.

Non-Wires Market Transformation

PGE entered into the GridWise™ demonstration project to determine if smart controls can limit power fluctuations and make the electric grid more resilient and cost-effective. The project includes an experiment in which customer loads can be controlled through a two-way energy price bidding process, and a field test of Grid Friendly™ appliances that automatically sense grid condition and curtail the appliance loads when doing so will help the electrical power grid.

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[2] See *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them*, p. vii, xx, 58-59. U.S. Dept. of Energy, Feb. 2006.

Energy Efficiency

PGE's Final Action Plan targeted 55 MWa of Energy Efficiency to be implemented through the ETO by the end of 2007. The ETO reports that they have captured 9.1 MWa of energy efficiency with PGE customers in 2004 and nearly 25 MWa in 2005, for a total of 34 MWa towards PGE's Final Action Plan target of 55 MWa. The 2005 numbers are preliminary as of March 2006. Based on this progress, the ETO appears to be well on-track to meet or exceed the energy efficiency target from our Final Action Plan.

ETO Annual Energy Savings (MWa)

	2004	2005	Total
Residential	4.0	4.2	8.2
Commercial	3.6	5.4	9.0
Industrial	1.5	15.3	16.8
Total	9.1	24.9	34.0

The Energy Trust collected over $25 million from PGE's customers during 2005 as part of the public purpose charge, and issued almost $19 million in incentives during the same period. PGE will continue to support and monitor the ETO's progress in this area.

Transmission Conditions in our IRP Acknowledgement

The Commission's acknowledgement of our Final Action Plan was conditioned on PGE taking a number of actions related to developing transmission capacity over the Cascades. As discussed below, PGE has been proactive in working with other regional entities to satisfy the conditions.

1. *PGE must initiate discussions with Staff, renewable developers, BPA, ETO and other stakeholders to discuss constraints to competitive renewable development in the region.*

PGE is actively engaged in regional discussions regarding constraints to competitive renewable development including:

McNary Open Season – BPA has planned to build a new transmission line from the McNary substation to the John Day substation and has offered to sell the capacity in an open season bid to interested parties. This proposed new transmission line, if built, would relieve transmission constraints in the McNary area.

PGE actively participated in the regional open season workshops and supported the process by submitting a request for 60 MW of firm transmission from the Stateline area to PGE's system. The McNary open season process has been suspended and replaced by BPA's modified available transmission capacity (ATC) methodology initiative, which should accomplish a similar result, i.e., new ATC over the West of McNary pathway.

Modified ATC Methodology – BPA changed the assumptions used to calculate the ATC on BPA transmission lines. This process has resulted in additional ATC over many of BPA's critical pathways including West of McNary. PGE actively participated in BPA's regional workshops and submitted comments and recommendations. PGE met twice with BPA in negotiation sessions to assure that the new methodology did not adversely impact current transmission contract rights. In the end, PGE supported BPA's methodology, and on July 1, 2005, BPA posted increased ATC over their system based on the modified methodology. Subsequent refinements have resulted in additional ATC since July 2005.

Conditional Firm Transmission Product – PGE supported the development of a conditional firm product during the BPA's 2006 Transmission Rate Case. One of the primary objectives of this initiative is to enable cost-effective transmission of intermittent wind without harming or burdening other transmission customers and users. This resulted in BPA's commitment to develop the product and to run an expedited 7(i) process to price the product if needed.

BPA studied the proposal and formed a new products work group. PGE was an active participant in this work group. BPA issued its initial draft proposal for a new product on December 23, 2004. After a review and comment period, BPA issued a revision to the new product proposal for Conditional Firm on June 6, 2005.

BPA has put this proposal on hold, pending completion of BPA's new Constraint Schedule Management (CSM) system. The CSM will give BPA the ability to delineate non-firm transmission over a path and curtail it before Conditional Firm. BPA has initiated regional dialogue on an implementation plan for CSM. PGE is actively engaged in the process.

Modification of BPA Firm Redirect Business Practice – PGE worked with BPA to modify its Firm Redirect business practice to allow the option to move Section 2.2 roll-over rights to the redirected point of receipt. This flexibility will enable current transmission holders who already possess firm transmission rights the ability to move those rights to new resources (e.g. new wind projects) subject to available transmission capacity. BPA has modified their business practices to allow transfer of Section 2.2 roll-over rights.

Grid West – PGE is actively participating in regional efforts to more efficiently run the Northwest transmission system, and has agreed to provide funding to Grid West, along with other parties, to allow the organization to develop a business plan. PGE will then decide whether to participate in Grid West development. BPA has recently discontinued its participation in Grid West and has initiated a parallel process. PGE will monitor and participate in the BPA effort as appropriate.

2. PGE must include an action item in its 2005 IRP to address how it will work with BPA and others to develop transmission capacity over the Cascades so that additional resources are accessible to PGE at a reasonable price.

OSU Transmission Study – In 2005 PGE engaged the Oregon State University (OSU) Engineering department to assist us in evaluating transmission options that would result in the ability to more efficiently utilize any remaining existing capacity over the Cascades, as well as potential facility additions that could result in new usable capacity. The primary objective of our contract with OSU was to conduct a physical transmission system examination of the constraints for moving power to PGE's system from the north, through the Interstate-5 corridor, and across the Cascades from Eastern Oregon.

The initial purpose of the study was to evaluate transmission flows and potential system upgrades and alternatives to relieve congestion on the South of Allston cutplane. The South of Allston cutplane, located north of Portland, is currently one of the most highly congested flow-gates on the BPA system and, as a result and due to its proximity to the PGE system, severely limits PGE's ability to secure new firm transmission rights from many points around the region, including the eastside of BPA's system.

Since the constraint caused by this cutplane will also block any effective use of new transmission capacity additions across the Cascades, South of Allston represents a least common denominator impediment to securing new resources to meet customers' future energy needs. Accordingly, first examining the physical causes of the South of Allston cutplane and potential ways to alleviate the constraint is critical.

PGE also asked OSU to investigate the technical feasibility of building a new transmission line from the McNary area to PGE's service territory in Salem. This expansion would use PGE's existing rights-of-way and would upgrade the Round Butte-Bethel line that connects the Pelton and Round Butte projects to PGE's system. We are currently referring to this potential transmission expansion as the "Southern Crossing." We selected this path for evaluation to potentially increase transmission capacity across the Cascades for several reasons:

- If new transmission facilities were built, the Southern Crossing could provide additional transmission capacity form Eastern Oregon to the Willamette Valley. Such new facilities would potentially relieve current east-to-west transmission congestion and provide additional capacity for new resources on the east side of the Cascades, including wind.
- The Pelton-Round Butte to Salem path offers the potential to use existing transmission corridors and rights-of-way, reducing such obstacles as permitting and securing easements.
- The Southern Crossing study offers synergy with other BPA and regional initiatives to increase east-to-west transmission efficiency and capacity.

Given the complexity and time-intensiveness of the South of Allston study, OSU was unable to complete all phases of the technical study for Southern Crossing under the 2005 scope of work. Therefore, we intend to evaluate alternatives to complete this technical feasibility study in 2006, including working with members of the OSU team that conducted phase I of the study.

PGE is also participating in several sub-regional transmission expansion planning efforts facilitated by the Northwest Power Pool. The Northwest Transmission Assessment Committee (NTAC) is currently assessing several regional transmission expansion options, including the Montana-Northwest Study Group, the Canada-Northwest-California Study Group, and the Northwest Wind Integration Study Group.

3. *PGE must demonstrate that it has made reasonable efforts to acquire, retain or option cost effective transmission capacity over the Cascades before issuing its next RFP.*

Point-to-Point Transmission – PGE procures firm BPA transmission capacity sufficient to meet 1-in-2 peak winter loads. This includes 750 MW of Rocky Reach and 400 MW of John Day-Big Eddy point-to-point (PTP) transmission service. Adding Port Westward in 2007 reduces our transmission needs by over 400 MW. We have worked with BPA to increase our ability to redirect these PTP purchases to deliver other resources, including renewables, to our load. PGE has extended both PTP agreements through 2010.

BPA's Firming and Shaping Product – Since wind is an intermittent resource with only limited predictability, additional resources and strategies are necessary to absorb the variability and allow utilities to meet unexpected deviations in generation. Following acknowledgement of our Final Action Plan, PGE continued its work with BPA to develop a product that provides storage and integration services for wind. However, BPA has since discontinued its product offering and ceased activity in this area due to uncertainty regarding their role in supplying the future energy and capacity needs of public customers.

BPA's proposed offering was structurally promising, but was limited in effectiveness as a long-term solution (only through 2011), due to BPA's inability to make a longer-term price commitment. We are also concerned that recurring court rulings with respect to federal damn operations will further diminish BPA's ability to offer this service in the future.

Looking Ahead – PGE's 2006 Integrated Resource Plan

As we move forward with completing the targeted resource and capacity actions from our Final Action Plan, we have begun to look ahead toward our next IRP, which we intend to file in December 2006. In preparation for our 2006 IRP, PGE has conducted or initiated a number of technical and economic research efforts to enhance our understanding of fundamental supply, demand, and technology drivers and influences that will ultimately impact the cost, risk and availability of future resources.

We are in the process of evaluating the future availability of our existing resources and forecasted customer energy needs to determine the timing and extent of our future resource requirements. At the same time, we have conducted customer surveys and a forum to directly gauge customer knowledge, preferences and concerns with respect to future resource choices. In the area of analysis, we have conducted a review of several third-party IRP analytical tools and selected a new model to enhance our risk and economic evaluation and decision-making. Finally, we plan to initiate a robust public process to provide the opportunity for all constituents to provide input and comment on the results of our research and analysis. These efforts are explained in greater detail below.

2006 IRP Studies

We are conducting a number of studies to support our analysis of IRP issues and concerns. Our goal is to better understand and evaluate such key issues as expansion of renewable resources, next-generation coal plants, carbon sequestration feasibility and reserve margins. This section provides a brief overview of studies that are currently planned or in-process to support our 2006 IRP.

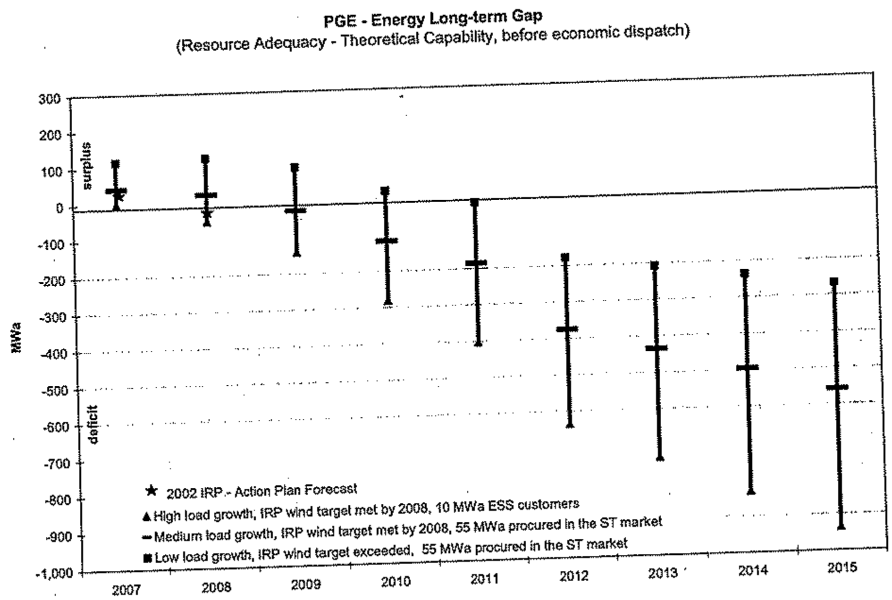
Load-Resource Balance

In our Final Action Plan we committed to procure approximately 790 MWa of resources to fill our expected annual average energy need by 2007-2008. We now expect to be in approximate load-resource balance on a resource adequacy basis by 2007-2008.

However, as we move forward we expect to experience customer load growth, resulting in a renewed deficit on a resource adequacy basis, and significant short-falls on an economic dispatch basis. This growing deficit is also driven by changes in our existing resource base over time. During the next few years some of our existing resources and long-term contracts will expire or are likely to be reduced in volume upon renewal.

In our 2006 IRP we will highlight the drivers of the projected gap and expand our evaluation beyond the traditional resource adequacy-based load-resource analysis to also consider an economic dispatch approach. This latter approach is based on the expected future dispatch of our thermal plants and contracts, and more accurately considers our actual short- to mid-term resource procurement needs.

The chart below shows the expected energy gaps for the years 2007 through 2015 based on a resource adequacy approach. For each year we have displayed a range of potential load and resource outcomes based on uncertainty surrounding some of the key assumptions and drivers in our forecast.



This figure shows three possible scenarios:

- High load growth of 3 to 3.3 percent a year with 10 MWa choosing service from an ESS. This is the maximum resource need with significant resource deficits starting in 2009.
- Medium load growth of 1.7 to 2.2 percent a year with 55 MWa choosing service from an ESS or market index pricing options. This is our initial modeling assumption for customers who will not return to a cost-of-service rate upon expiration of the shopping credit tariff

provision.[3] In this scenario, deficits begin to appear in 2010 and 2011 and become material in 2012.

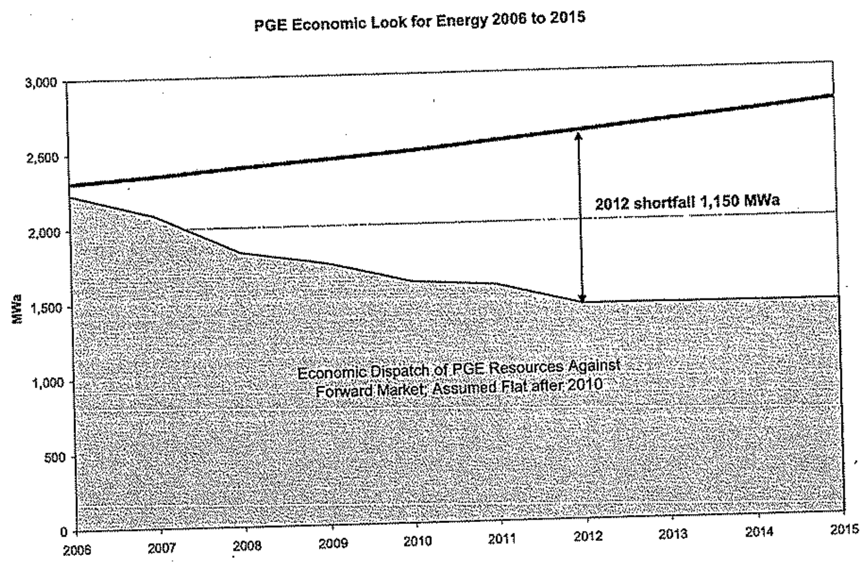
- Low load growth of 1.1 percent a year with 55 MWa selecting ESS service or market index pricing options. Under this scenario we also forecast increasing resource deficits by 2012.

In the longer term, the energy gap range widens because of load uncertainty, and the deficits deepen due to a material reduction in existing resources in 2012 caused by the expiration or renegotiation of several mid- to long-term contracts. These include Mid-Columbia hydro, Confederated Tribes of the Warm Springs (Pelton-Round Butte) and PPAs executed in connection with the 2002 IRP Final Action Plan.

For resources that will be renegotiated or renewed, we expect that we will retain less output from the resource than we currently enjoy. This assumption is based on discussions with the resource owners or suppliers and by observing the results of renewals or renegotiation activities by other utilities in the region for similar contracts.

The figure above shows the traditional IRP load resource balance from a resource adequacy perspective, before considering economic dispatch of our thermal plants and contracts. Load and resources are computed assuming "normal" conditions such as weather, hydro production and plant operations. The chart below shows PGE's estimated future resource needs taking into account economic dispatch of our resources.

[3] A shopping credit is an incentive for customers to acquire energy from an ESS. The 10 MWa estimate is consistent with PGE's general rate case filing (UE 180). We assumed 55 MWa from ESS or variable pricing options in our IRP Key Customer Workshop on March 1, 2006.

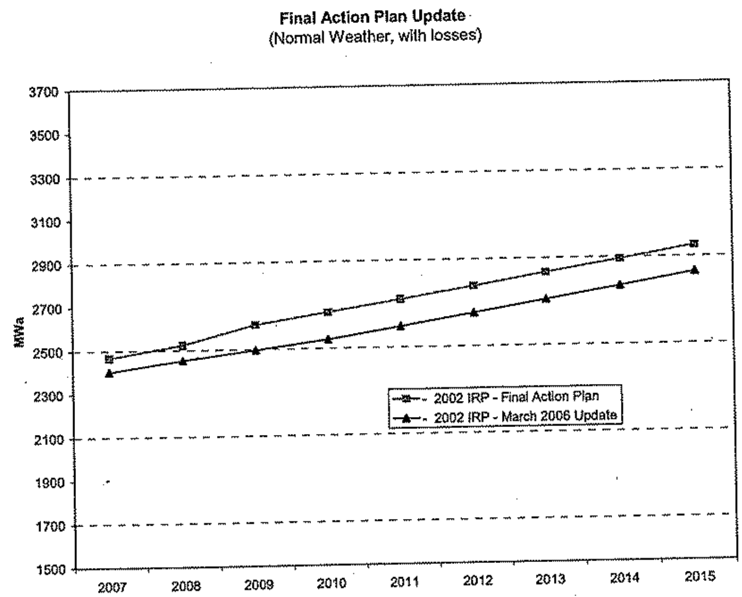


The relative dispatch cost of our natural gas-fired resources and contracts compared to the marginal price of electricity in the market continues to change over time as more efficient resources, like Port Westward, are added to the Pacific Northwest (PNW) regional portfolio. In addition, the abundance of hydro generation in the PNW results in displacement of most thermal resources during the spring and early summer months and at certain other times during off-peak hours. As a result, the load-resource balance of our portfolio on a resource adequacy basis and an economic dispatch basis diverge. The latter assessment shows larger deficits and a higher reliance on short-term market purchases.

Given the continued increase in efficiency for the regional energy portfolio, higher heat rate thermal units such as Beaver are becoming intermediate duty plants that provide base-load energy only during the peak months and peaking capacity during the balance of the year. We also account for seasonal variations in market pricing and market-clearing heat rates that periodically displace more efficient units such as Coyote and Port Westward. These variations are largely driven by abundant regional hydro energy in the spring and early summer months.

In our 2006 IRP we intend to assess our resource needs on a resource adequacy and economic dispatch basis to better understand the costs and risks of managing our portfolio and implementing new resource decisions.

The figure below compares the load forecast of the Final Action Plan with the most recent forecast. We report system load net of energy efficiency measures.



The current annual average load projection for 2007 is about 65 MWa lower than what we published in our Final Action Plan. By 2010, the difference grows to 125 MWa. The lower load projection is explained by:

- Reductions in energy consumption caused by sustained high energy prices.
- Industry or business specific factors affecting a few large customers.

Our industrial and commercial load is affected by lower consumption from three large customers. One customer revised its expansion plans for its Oregon operations, another increased its amount of self generation, and a third customer increased its efficiency with an ETO-sponsored project.

Based on the preliminary analysis described above, we expect that new mid- to long-term resources will be required by 2012 to ensure that we meet our customers' energy requirements. In that year our mid-case estimate shows a deficit of about 370 MWa, on a resource adequacy basis, to meet our annual average energy needs. Capacity needs by 2012 are greater and will be addressed in detail in our 2006 IRP.

Reserve Margin Requirement

This study will assess the risks and costs of the amount of resources that PGE maintains to meet peak load requirements and unexpected deviations in load and generation. The goal of this study is to examine the cost and risk trade-off of providing reliability and price stability at various levels. Besides looking at our reliability and economic metrics, we will also examine what other utilities have proposed and what has been acknowledged in their IRPs.

We will also consider the current initiative to evaluate reserve margins that the Northwest Power and Conservation Council (NWPCC) is undertaking, in collaboration with regional utilities, to define guidelines and metrics for measuring energy and capacity resource adequacy.

Wind Integration

This analysis will help define how much wind PGE can integrate and determine the supply curve of integrating wind as higher volumes are added to our system. Through the study we intend to examine both operational and reliability considerations, as well as economic impacts.

Uncertainty Analysis

As part of our resource and portfolio modeling PGE intends to conduct various forms of analysis, including scenario, sensitivity and stochastic probabilistic analysis. Performing and considering the results of different analytical approaches is necessary to adequately assess the risk and economic factors associated with future resource decisions and to provide better insights regarding potential future outcomes.

To ensure that our analysis is robust and well-considered, PGE is engaging an outside expert to study uncertain power supply factors such as natural gas and electricity prices, loads, and hydro output. This assessment of the relationships and uncertainties of these key economic drivers will inform our resource choices.

Customer Outreach

An important objective for our 2006 IRP process is to ensure that PGE has conducted a robust dialogue with all stakeholders regarding future resource needs and choices. Providing opportunities for our customers to participate in the process and voice their preferences is key to meeting that objective. To accomplish this goal, PGE has conducted a three-phased customer outreach research initiative to directly assess customer views about risk and value considerations for resource decisions. We also learned about specific customer preferences for potential resource alternatives.

- Phase one, conducted in mid-2005, involved a series of focus groups, two for mid-tier businesses, and two for residential customers. Our industrial key accounts were also sampled through in-depth interviews. The focus groups provided an opportunity to qualitatively assess customer priorities and receive direct unfiltered responses regarding electric supply choices.
- Phase two was conducted in late-2005 using a randomly sampled survey approach for residential, commercial and large industrial customers. The statistically valid sampling included survey results that are now being analyzed and tabulated to provide a quantitative assessment of customer power supply preferences and attitudes for important resource considerations such as cost, price stability, reliability and environmental impacts.
- Our most recent activity was a Key Customer Group IRP Forum held in March 2006. The forum included representatives from several of our largest business customers, as well as PGE's IRP managers and resource subject matter experts. During the forum we presented information related to our potential energy needs and resource alternatives to meet those needs. We also solicited direct responses from the participants regarding their objectives, concerns and preferences for PGE's energy supply and resource choices.

The combined results of these customer studies will be summarized in our 2006 IRP and we anticipate using these responses to inform our resource decisions.

Transmission Study

As described earlier in this document (see "Transmission Conditions in our IRP Acknowledgement"), PGE is conducting transmission studies to assess potential solutions to enable new generation resources from east of the Cascades. The studies will evaluate the technical feasibility of potential system upgrades and improvements to existing transmission facilities within the South of Allston cutplane. This system constraint must be remedied to make effective use of new transmission capacity across the Cascades.

We are also studying a cross-Cascades transmission path from Eastern Oregon to the Willamette Valley by upgrading and expanding the reach of existing PGE transmission facilities. This latter expansion has the goal of increasing capacity and integrating new sources of supply.

Fuels and Generation Technologies

Since acknowledgement of our Final Action Plan, the wholesale energy markets and resource technologies have continued to evolve. During this time many events have occurred that have affected the availability and price of generating electricity. One of the most significant of these changes has been in the area of fuel cost and availability.

Over the last few years increases in hydro-carbon commodity prices have impacted virtually all fossil-fueled generation sources. Prices for natural gas, oil and coal have all experienced increased volatility and higher price levels. Beyond these changes there is an increasing awareness that domestic extraction of natural gas is not keeping pace with demand. Due to these factors and others it will be increasingly necessary to consider alternative energy sources.

PGE thus intends to examine several alternative resources, fuels and related initiatives. In addition to continuing our close examination of expanding renewable energy and demand-side options, PGE also intends to consider next-generation and clean coal technologies, global and national LNG forecasts and West-coast opportunities, future emissions initiatives and impacts (including carbon sequestration feasibility) and emerging generation technologies. By doing so, we hope to deepen our analysis and discussion of the risks and trade-offs associated with our future resource options.

Coal Technology Study

In 2005 PGE retained Black & Veatch to investigate and compare coal-fueled generating technology options for PGE's integrated resource plan. The study compared super-critical pulverized coal (SCPC) and integrated gasification combined cycle (IGCC) technologies. Performance and cost estimates were developed on the basis of a Powder River Basin coal supply.

To provide specific and accurate costs, the study is based on adding a second unit at the site of our Boardman Coal Plant. The study results can also be generalized to evaluate the cost of a mine-mouth site. We will assess these two technologies and their related costs and risks independently, considering the relative merits of each technology.

Study deliverables include technical specifications, cost estimates (installed cost per kW), emissions estimates and development timelines, along with conclusions and recommendations about the generation technologies based on economics and risk factors.

Carbon Sequestration

Recently PGE engaged Cornforth, a local geology consultant, to do a preliminary assessment of the geological carbon sequestration potential in the lower Columbia River basin (the area of our Boardman site) and at mine-mouth coal sites in Montana or Wyoming. This study will also identify the potential for collaborative work with WestCarb and Big Sky. The results of this study will be used to inform our assessment of the emissions-related risks and potential mitigation factors for carbon-intensive thermal generation resources.

Fuels Research – Coal

PGE is reviewing long-term forecasts by Hill & Associates, Inc. for U.S. steam coal and Powder River Basin coal supply, demand, and prices. We are also following allowance values for sulfur dioxide, nitrogen oxides, carbon dioxide, and mercury emissions. In addition, we are evaluating the effects of the EPA's Clean Air Interstate Rule and Clean Air Mercury Rule, and are monitoring legislation related to proposed emissions limits and cap and trade programs.

Fuel Research – Natural Gas

PGE has subscribed to weekly, monthly and annual reports from PIRA Energy Group to better understand short and long-term natural gas fundamentals with respect to supply, demand and price. For IRP purposes PGE will focus on the long-term studies PIRA conducts.

Fuel Research – Liquefied Natural Gas

PGE has subscribed to PIRA's Global Liquefied Natural Gas (LNG) service and will review factors affecting supply, demand and the price of LNG. We will also assess the potential for LNG to become a future fuel source for regional and PGE natural gas-fired generating plants by monitoring efforts to bring LNG regasification facilities to Oregon and to the West Coast.

Pacific Northwest Climate Study

PGE has commissioned a study from the University of Washington to assess the potential effects specific to the Pacific Northwest of global climate change, including potential impacts to precipitation and snow-pack. The study will also assess potential temperature changes that could affect our heating and air conditioning needs.

EPRI Wave Energy

Wave energy is an emerging technology that is currently receiving greater attention due to its potential global abundance. Should this technology be further developed and commercialized, the potential benefits to Oregon and PGE customers could be significant. As a result, PGE has taken steps to monitor and support local wave energy initiatives. On the local front, Electric Power Research Institute (EPRI) and Oregon State University are conducting a wave-action study to assess various technologies for generating electricity from waves. EPRI has published their *Oregon Offshore Wave Power Demonstration Project* report, and has turned all Oregon wave energy research over to OSU and People of Oregon for Wave Energy Resources (POWER) for further research and development.

POWER is headed by Justin Klure of the Oregon Department of Energy, and seeks to establish a wave energy demonstration project offshore from Reedsport, Oregon. POWER's long-term goal is to support installation of one or more utility-scale wave energy parks along the Oregon coast, which would provide local jobs for fabrication and servicing the equipment.

OSU may conduct research on various wave energy generator devices at a node on the demonstration project. Alternatively, they may establish an ocean wave research area closer to Newport and the Hatfield Marine Science Center. PGE and Oregon Iron Works are supporting OSU's development of a linear test bed for conducting research on prototype wave energy generators.

Selecting PGE's IRP Analytical Model

In the Acknowledgement Order for our 2002 IRP, the OPUC encouraged PGE to acquire more sophisticated and powerful analytical tools before proceeding with the next IRP. After exhaustive due diligence of several analytical products, we selected EPIS' Aurora^xmp® model in December 2005.

Aurora compared favorably with other models because of its user-friendly interface and its extensive data base. It is also well accepted for use in long-term energy planning analysis in the Pacific Northwest. Regional users of Aurora include: NWPCC, Avista, Idaho Power Company and Puget Sound Energy.

We have also made a full license and training available to OPUC staff to ensure that our modeling and analytical processes remain transparent and open to critical review. We expect the Aurora model to provide us more detailed insights about our portfolio mix and the risks we face in making future resource decisions, due to its hourly granularity and regional unit-commitment modeling capabilities.

After we run our power cost estimates in Aurora, we will then enter them into our Transition Cost Model (TCM), which is the modeling tool we used in our 2002 IRP. The TCM will merge the power cost estimates with the expected fixed and capital costs of the trial portfolios and existing resources, and calculate the long-term cost of the trial portfolios based on the net present value of revenue requirement (NPVRR).

We will then assess the cost of the candidate portfolios under deterministic and stochastic assumptions for fuel and electricity. We will also evaluate a few long-term scenarios such as critical hydro and a high CO_2 tax, and rank the portfolios by cost and risk. Finally, based on these results we will propose and discuss with our stakeholders the best portfolios to meet our future needs.

FERC Standards of Conduct and Resource Planning

With the advent of the FERC Standards of Conduct (SoC), PGE finds it difficult to gather required transmission information to adequately assess related generation alternatives. On September 24, 2005, PGE joined with Puget Sound Energy in meeting with FERC staff to discuss the difficulties the SoC present regarding integrating transmission requirements into generating decisions.

On October 11, 2005, Chairman Lee Beyer of the OPUC also sent then-Chairman Joseph Kelliher of FERC a letter describing the issues in preparing an IRP under FERC Order 2004 due to the difficulty of obtaining adequate transmission information.

Chairman Kelliher acknowledged the potential barriers in some circumstances and suggested either possible organizational remedies or the possibility of requesting a limited waiver of the rules. PGE continues to assess which approach is likely to best provide needed transmission information and meet the goals of the IRP.

Timing of Next IRP

We intend to file our next IRP by the end of 2006. As presented above, we have already concluded many preparatory studies. Others are being launched or are well underway. We met with customers in March to discuss our future resource needs and the IRP process. We also plan to hold approximately six public meetings, one per month beginning in April, to discuss our research, analytical methods and findings, and to elicit responses from PGE stakeholders and interested parties. Our tentative schedule of meeting topics is listed below.

PGE's Load-Resource Balance, Scope of IRP, April 2006

- Introduction: cost, price stability, environment
- IRP Update *vs.* Final Action Plan
- Regional load-resource balance
- PGE load-resource balance
- Detailed work plan for evaluating the portfolio for least cost, risk, and diversity
- IRP studies
- Full stakeholder dialogue agendas
- Outline of 2006 IRP

Demand-Side Management & Externalities, May 2006

- Follow-up, open items from previous meeting
- ETO energy efficiency forecasts
- Customer outreach studies
- Demand response
- Combined heat and power

- Dispatchable Standby Generation
- Real time pricing rate design
- AMI update
- CO2 tax and PGE climate change policies
- RPS potential

Candidate Supply-Side Resources, June 2006

- Follow-up, open items from previous meeting
- Technologies
- Generic cost inputs
- Renewables
- Biomass
- Wave energy
- Wind integration
- Distributed nuclear (OSU)
- Coal technologies
- CO2 sequestration
- UW climate study

Fuels and Transmission, July 2006

- Follow-up, open items from previous meeting
- Fuels fundamentals
- Coal
- Emissions and environmental issues
- Transmission constraints and solutions, OSU studies

Candidate Plans, August 2006

- Follow-up, open items from previous meeting
- Candidate trial plans
- Issues and questions to be addressed in the IRP
- Distributions and correlations of stochastic inputs
- Modeling and analysis issues
- Risk metrics in models
- Diversity characteristics

Trial Plan Analysis, September 2006

- Follow-up, open items from previous meeting
- Trial plan results
- Stochastic results
- Sensitivity results

Conclusion

Since acknowledgement of the 2002 IRP Final Action Plan, PGE has focused on effective implementation to ensure congruence and continuity between our planning and procurement processes. As a result of these efforts PGE has now completed all targeted resource actions except the acquisition of an additional 38 MWa of wind energy. Negotiations to complete this remaining action are also nearly complete, at which point PGE will have in all material respects met the resource targets from our Final Action Plan. Throughout this implementation process PGE has remained mindful of changing conditions and vigilant to ensure that the resource actions taken continue to meet the objectives of the IRP.

PGE has further taken numerous steps to satisfy the conditions of the OPUC acknowledgement order related to transmission, demand response, energy efficiency and CHP resource potential. While some of our activities in response to these conditions will continue, we believe that our actions to date evidence PGE's fulfillment of the Commission's order in this area.

Finally, we also recognize that resource planning is a continuum with new resource needs emerging even as we complete the actions from our last IRP. As a result, PGE is currently in the process of launching its 2006 IRP, which we expect to file in December 2006. Initial results of our load-resource balance assessment for the next IRP indicate that PGE will have material resource needs on a resource adequacy basis shortly after the end of this decade. We are further forecasting significant resource needs on an economic dispatch basis starting in 2007. Addressing these future needs will require consideration of many factors that affect risk and value associated with resource choices. Doing so will require robust research, analysis and an open dialogue with the many PGE constituents that are impacted by our resource decisions. We intend to remain focused on these objectives as we conclude our 2002 IRP Final Action Plan and move forward with our 2006 IRP. We look forward to working with the Commission and stakeholders as we prepare our 2006 IRP.

Appendix

- Joint letter to Oregon's delegation urging renewal of the PTC

Portland General Electric ▪ Puget Sound Energy ▪ PacifiCorp

NorthWestern Corp. ▪ Citizens' Utility Board of Oregon

Washington State Office of Community, Trade, and Economic Development

July 7, 2004

The Honorable Gordon Smith
United States Senate
404 Russell Office Building
Washington, D.C. 20510

Dear Senator Smith:

We are writing to thank you for your continued support of the Production Tax Credit (PTC) for renewable energy, and to ask for your assistance in refining the PTC provision included in the House and Senate FSC/ETI bills during the conference process. Your continued active engagement will be essential in ensuring that the final bill addresses the needs of Northwest renewable energy stakeholders and electricity customers and in providing much-needed economic development and job creation for the Northwest.

The expiration of the PTC on Dec. 31, 2003 – and continuing uncertainty about the duration and form of any extension – have virtually halted new renewable resource procurement in the Northwest. The lack of a PTC has put the renewable energy resource procurement plans of the four Northwest utilities signing this letter in a "holding pattern." To allow Northwest utilities to follow through on their resource acquisition plans, the PTC must be extended at least until January 1, 2007 and must include the inflation index provision that is in current law.

Given the uncertain schedule for enactment the FSC/ETI legislation, extension of the PTC through 2005 as contained in the House bill would not deliver a robust renewable energy portfolio for the region. Utilities must complete negotiations for projects, developers must obtain the necessary turbines and construction and commissioning must be completed for projects to qualify for the credit. At this point in time, some projects contemplated by utilities and developers could not practically be placed in service by December 31, 2005. Further, continuation of the inflation adjuster provision is a critical factor in making wind projects more cost competitive for utility consumers.

PacifiCorp, Portland General Electric, Puget Sound Energy and NorthWestern must acquire new generation resources in the near future to meet the growing needs of their customers. These utilities want to add renewable resources — particularly wind power — to their respective power supply portfolios because, with the PTC, wind is increasingly cost-competitive with other new resources, such as gas and coal fired generation. Wind power also acts as an important hedge in utility portfolios against the risk of fuel price volatility and further environmental restrictions on thermal generation. With the PTC, investment in wind resources creates a rare confluence of good energy policy, good environmental stewardship, and good economic opportunity for the region.

In closing, we again thank you for your continued support for this critical issue and we hope to continue to work with you to gain timely extension of a PTC through 2006 as well as to maintain an inflation adjuster.

Best regards,

Peggy Y. Fowler

Peggy Y. Fowler
CEO & President
Portland General Electric

Stephen P. Reynolds

Stephen P. Reynolds
President & CEO
Puget Sound Energy

Judi Johansen

President & CEO
PacifiCorp

Margin and Effective Tax Rate in UE-180
Adjusted for Disallowed Costs
Example Using Updated PGE Filing as Base
Dollars in $000

	PGE Results w/O&M, Depr Updated NVPC	SERP	MDCP	Image Adver	Cat A Adver	3-Year Wages	Incentive Pay	Member	Adjusted Results
	(1)	(2)	(3)	(4)	(5)	(8)	(9)	(10)	(11)
Operating Revenues									
Sales to Consumers (Rev. Req.)	1,684,538								1,684,538
Sales for Resale	-								-
Other Operating Revenues	17,768								17,768
Total Operating Revenues	1,702,305	-	-	-	-	-	-	-	1,702,305
Operation & Maintenance									
Net Variable Power Cost	866,680								866,680
Total Fixed O&M	149,586								149,586
Other O&M	164,524	1,544	5,092	1,056	435	3,534	4,366	179	180,730
Total Operation & Maintenance	1,180,790	1,544	5,092	1,056	435	3,534	4,366	179	1,196,996
Depreciation & Amortization	176,844								176,844
Other Taxes / Franchise Fee	84,648								84,648
Income Taxes	78,792	(607)	(2,003)	(415)	(171)	(1,402)	(1,732)	(70)	72,391
Total Oper. Expenses & Taxes	1,521,074	937	3,089	641	264	2,132	2,634	109	1,530,879
Utility Operating Income	181,231	(937)	(3,089)	(641)	(264)	(2,132)	(2,634)	(109)	171,426
Rate of Return	8.97%								N/A
Return on Equity	10.75%								N/A
Average Rate Base									
Utility Plant in Service	4,595,610					1,029	1,271		4,597,910
Accumulated Depreciation	(2,467,842)								(2,467,842)
Accumulated Def. Income Taxes	(207,435)								(207,435)
Accumulated Def. Inv. Tax Credit	(5,005)								(5,005)
Net Utility Plant	1,915,328	-	-	-	-	1,029	1,271	-	1,917,628
Misc Deferred Debits	4,689								4,689
Operating Materials & Fuel	50,176								50,176
Misc. Deferred Credits	(28,082)								(28,082)
Working Cash	79,096	49	161	33	14	111	137	6	79,606
Total Average Rate Base	2,021,206	49	161	33	14	1,140	1,408	6	2,024,016
Income Tax Calculations									
Book Revenues	1,702,305	-	-	-	-	-	-	-	1,702,305
Book Expenses	1,442,282	1,544	5,092	1,056	435	3,534	4,366	179	1,458,488
Interest Rate Base @ Weighted Cost of l	59,152	1	5	1	0	33	41	0	59,234
Production Deduction	4,017								4,017
Temporary Sch M Differences	(21,840)								(21,840)
Permanent M Differences	(7,623)								(7,623)
State Taxable Income	226,318	(1,545)	(5,097)	(1,057)	(436)	(3,567)	(4,407)	(179)	210,029
State Income Tax	14,808	(102)	(337)	(70)	(29)	(236)	(292)	(12)	13,731
Federal Taxable Income	211,510	(1,443)	(4,759)	(987)	(407)	(3,331)	(4,116)	(167)	196,299
Fed Income Tax	74,028	(505)	(1,666)	(346)	(142)	(1,166)	(1,440)	(59)	68,705
Deferred Taxes	(8,583)								(8,583)
ITC Amort	(1,461)								(1,461)
Total Income Tax	78,792	(607)	(2,003)	(415)	(171)	(1,402)	(1,732)	(70)	72,391
Net to Gross Margin	11.92%								10.96%
Effective Tax Rate	39.23%								39.22%
Check	78,792								72,391

Unexpected Outage Days for Colstrip, Boardman, Poor Water versus Earnings Power of Production Assets
Dollars in $000s

Days of Unexpected Outage to Absorb Earnings Power:

	Fuel Cost per MWh	Mid C per MWh	Delta	Capacity MW	Asset Earn Pwr	Days of Outage to Earn Pwr	Production Earn Pwr	Days of Outage to Earn Pwr
Boardman	12.9	67.64	54.74	380.3	$ 8,964	18	$ 46,608	93
Colstrip	7.5	67.64	60.18	293.6	$ 6,384	15	$ 46,608	110

Days of Low Hydro to Absorb Earnings Power:

	Fuel Cost per MWh	Mid C per MWh	Delta	Avg Energy Owned Hydro aMW	Asset Earn Pwr	Days of 90% Hydro to Earn Pwr	Production Earn Pwr	Days of Outage to Earn Pwr
Owned Hydro	-	67.64	67.64	218	$ 5,919	167	$ 46,608	1,318
Contract Hydro	-	67.64	67.64	361	-	-	$ 46,608	796
Combined	-	67.64	67.64	578	$ 5,919	63	$ 46,608	496

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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.

Our qualifications are in our direct testimony, PGE Exhibit 1100, Section VII.

Q. What is the purpose of your testimony?

A. Our rebuttal testimony addresses the following items:

- We update our cost of capital estimates for long-term debt, common equity, and preferred stock.
- We explain why Staff witness Conway's proposed adjustment to the Company's embedded long-term debt costs should be rejected.
- We raise concerns regarding the analysis performed by Staff witnesses Morgan and Conway regarding PGE's cost of capital, including the methods they use, the errors in their analyses, and the general overall results that their recommendations will have upon PGE's finances in 2007 and beyond.
- We rebut their arguments regarding our cost of capital analyses, showing that our methods, while not perfect, provide better guidance for the Commission than does Staff's single method.

- We briefly respond to the cost of capital testimony submitted by Industrial Customers of Northwest Utilities – Citizens' Utility Board ("ICNU-CUB") witness Gorman.

Q. How is your testimony organized?

A. There are two sets of testimony, ours and Dr. Zepp's. Our testimony concentrates on updating our cost of capital analysis and correcting/rebutting many of Staff's analyses. Dr. Zepp demonstrates various other DCF and Risk Premium methods that can be used to address many of Staff's concerns and provide the Commission with a more complete record upon which to determine PGE's cost of equity capital.

Q. What conclusions do you reach in your testimony?

A. First, we accept Staff's recommendation regarding preferred stock and remove it from our capital structure.

Second, we demonstrate that Staff's analysis regarding the "Enron bankruptcy effect" ignores the significant deterioration and volatility of the financial and wholesale energy markets during the 2001-2003 period and its significant effect on utility credit ratings. Considering the impact of these effects minimizes the Enron bankruptcy effect, if any, on PGE's embedded cost of long-term debt.

Finally, we find that, although we disagree with Staff's Discounted Cash Flow (DCF) sample and methodology, if we correct the errors in Staff's analysis and use stock prices over a realistic period, instead of one day, Staff's estimated range would be 8.38% to 10.23% (PGE Exhibit 2013), which is closer to our range. We also address Staff's concerns regarding the Risk Positioning model and find that Staff's "demonstration" using random numbers is incorrect and show mathematically that our model specification is correct.

II. Updated Cost of Capital Estimates

Q. Have your cost of capital estimates changed since your initial analysis?

A. Yes. As discussed in our supplemental cost of debt testimony (PGE Exhibit 1400) our revised cost of debt has increased from 6.69% to 6.83%. We do not make any further adjustments in our rebuttal testimony. We removed PGE's Preferred Stock from our cost of capital estimate because it matures midway during the year and it is a very small part of PGE's capital structure. Finally, our range for PGE's Required Return on Equity (RROE) changed slightly but our estimate for PGE's RROE remains at 10.75%. As indicated in our direct testimony, this 10.75% RROE assumes adoption of the NVPC regulatory framework proposed by Ms. Lesh and Mr. Niman (Exhibit 400). PGE Exhibit 2001, and reproduced in Table 1, below provides our updated 2007 cost of capital estimate for PGE.

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

Component	Average Outstanding ($000)	Percent of Capital	Cost	Weighted Cost
Long-term Debt	$997,280	43.88%	6.826%	3.00%
Preferred Stock	-	-	-	-
Common Equity	$1,275,487	56.12%	10.75%	6.03%
Total	$2,272,767	100.00%		9.03%

We discuss our updates for PGE's RROE and capital structure below.

A. PGE's Updated Required Return on Equity

Q. How did you update your estimate for PGE's Required Return on Equity (RROE)?

A. We performed the same Discounted Cash Flow (DCF) and Risk Positioning analyses that we did for our direct testimony, except that we used information and data through August 31, 2006. In other words, we checked each of our DCF and Risk Positioning samples for consistency, using the criteria we set forth in our direct testimony. We then updated our forecasts as appropriate, developed a range for each of the three samples, and then an overall range. Given the overall range, we then determined whether PGE was more or less risky than the overall sample and, using our expert judgment, developed a point estimate for revenue requirement purposes.

Q. Did your samples change significantly from your initial analyses?

A. No. For our DCF analysis, a few companies are no longer part of our sample because they did not meet one or more of our criteria. For example, Constellation Energy, FPL Group, and WPS are in merger discussions and are no longer included in our sample. We also checked those companies that we had eliminated in our initial analysis to determine if any could now be included. We have now included American Electric Power, CenterPoint Energy, TECO, TXU, Alliant, and Westar in our samples because their dividend reductions were more than three years ago. PGE Exhibit 2024 shows our updated DCF sample companies.

For our Risk Positioning analysis, we reviewed our dataset per Staff's suggestion and found that we needed to add one observation and remove another – PGE's UE 115 and PacifiCorp's UE 170 decisions. We added the first observation to our almost 500 observation point sample because the UE 115 authorized ROE decision was a contested One. We removed the second observation because the authorized ROE in UE 170 was the result of a stipulation and should not have been included. We found that doing so did not change our results to any significant degree.

Q. What is your updated range for PGE's RROE?

A. Our updated range remains 9.25% to 11.30%. We base our overall range on a number of factors, including the ranges for our DCF and Risk Positioning analyses and our expert judgment, and note that the ranges did not change significantly since our initial filing. Table 2 below summarizes our results.

Table 2

Summary Results for PGE's RROE

Method	Low	High
Multi-stage DCF - *br+vs*	8.20	10.10
Multi-stage DCF – GDP	8.30	11.30
Risk Positioning – 7-Year Treasuries	11.1	11.3
Risk Positioning – Corporate Bonds	10.8	10.9

Our detailed updated RROE estimates are PGE Exhibits 2002 and 2003. The supporting documents are contained in our hardcopy and electronic work papers.

Q. Did you adjust your RROE analyses based on the concerns expressed by Staff, ICNU, or CUB?

A. We did evaluate the Staff and ICNU-CUB concerns regarding our analyses and performed some modified analyses to address them. For the most part, we found that their concerns were either unfounded or the modified results were not significantly different from our initial analyses. We discuss Staff's and ICNU-CUB's concerns in Sections IV, V and VI below. We also note that Dr. Zepp also discusses Staff's and ICNU-CUB's concerns and provides DCF and Risk Premium analyses that address some of the issues raised by both parties.

Q. Have there been any recent events that would cause you to re-evaluate your RROE recommendation?

A. Yes, there have been two events. First, SB 408 rules are nearing completion so the impact on utilities in Oregon is somewhat clearer. The Commission's Interim Order in AR 499 (Order No. 06-400) agreed with the utilities that the effect of SB 408 and the associated rules would result in more volatility in earnings. In that Order, the Commission acknowledged "the predicament of the utilities" on this point and indicated that it would consider these tax effects "when evaluating issues in other dockets, such as power cost adjustment mechanisms." While acknowledging the "general concerns raised by the utilities," the Order states that any proposed solution to address the so-called "double whammy" situation "would be contrary to the intent of the legislature," and declined to remedy the issue. The increased volatility in earnings – now acknowledged by the Commission in Order No. 06-400 – raises utilities' risk and would lead us to move our point estimate closer to the top of our range, as no other utility in the U.S. (outside of Oregon and possibly Pennsylvania) bears this risk. Moreover, unlike PacifiCorp – which has less exposure to this issue because nearly 70% of its operations are located outside of Oregon – PGE has no multi-jurisdictional diversity that would permit it to avoid the full impact of SB 408's negative implications. As shown in PGE Exhibit 2007, PGE's financial volatility is measured by standard deviations of EBIT and ROE is already higher than the average.

Second, a recent state Supreme Court decision regarding the availability of civil actions to overturn rates that were never stayed or even appealed, injected more uncertainty into final rate decisions by the OPUC, which would also increase the financial risk. Again, given this recent decision, we would move our point estimate even more towards the top of the range.

B. PGE's Updated Capital Structure

Q. Did you adjust your forecast for PGE's 2007 capital structure?

A. Yes, but very slightly. As we noted above, we removed the Preferred Stock from the 2007 capital structure, lowering PGE's 2007 capital structure by approximately $6.6 million and resulting in an overall cost of capital of 9.03%.

C. Updated Recent Authorized ROEs

Q. Have you updated your Exhibit regarding recently determined authorized ROEs?

A. Yes. PGE Exhibit 2005 provides additional authorized ROEs through June 2006. Our initial exhibit (PGE Exhibit 1111) contained authorized ROEs through December 2005.

Q. Have recently issued authorized ROEs been higher than Staff's recommended 9.3% for PGE?

A. Yes. All of the 12 decisions since January 1, 2006, have been higher than 9.3%[1]. Of the 12 decisions, three were above 11%. More than half were above 10.6% and only one was lower than 10.0%. That instance was United Illuminating, a transmission and distribution only utility, which received a 9.75% authorized ROE decision in January.

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[1] One decision was a "black box" settlement and no inference regarding cost of capital is possible.

III. PGE's Cost of Long-Term Debt

Q. Have you updated your estimate for PGE's expected $100 million issue in 2007?

A. Yes. Our estimated rate for our expected debt issue remains at 6.50%. This estimate is based primarily on our discussions with investment bankers and maintaining our BBB+ rating. Updating our analysis using publicly available information from *Global Insight*, our estimate would be 6.60%. For convenience, we have reproduced PGE's long-term debt exhibit as PGE Exhibit 2004. Our estimate for PGE's embedded cost of long-term debt in 2007 remains at 6.826%.

Q. Staff recommends 6.30% as PGE's 2007 long-term cost of debt compared to PGE's requested 6.826%. Do you agree with Staff's recommendation?

A. No, for several reasons. First, PGE's long-term debt issuances since our last general rate case should be examined on a portfolio basis, not necessarily on an issuance by issuance basis. Second, Staff adjusts six of PGE's long-term debt issuances because they contend, without evidentiary foundation, that there was a significant "Enron bankruptcy effect" on PGE's cost of long-term debt. Third, Staff states, but does not further explain, that PGE made "judgment errors" (Staff Exhibit 1200, page 2, lines 21-22). Fourth, Staff re-priced PGE's forecasted 2007 $100 million debt issuance "to be consistent with current interest rates" (Staff Exhibit 1200, page 3, lines 1-2) rather than considering forecasted interest rates in 2007 when PGE will actually issue the debt.

A. PGE's Long-Term Debt Issuances Have Been Prudent

Q. Staff examines each long-term debt issue to determine whether there was an Enron effect. Is this the only way to determine if PGE's long-term debt costs are prudent?

A. No. Staff's issue by issue review implies that PGE must "beat the market" when it issues debt, whether the market is defined as a comparison to PacifiCorp, Northwest Natural, or some other proxy. This is unrealistic. It would be extremely difficult to sort out each of the factors that affected PGE's debt issuance cost. For example, as we discussed in our direct testimony, during this time, the financial and wholesale energy markets for electric utilities were very volatile, which would increase financing costs. In addition, utility bond issuances tend to be unique to the utility because each utility has different risks, which would cause different spreads over Treasuries. Further, an issue may differ by size, term, call provisions, etc. Thus, acquiring a robust sample would be very difficult, especially for such a limited time period.

A more appropriate overall consideration would be to consider the debt issuances on a portfolio level. That is, since Fall 2001, one should analyze whether PGE's incremental cost of debt has been above, equal to, or below the cost of debt for similarly rated electric utilities. If Staff's belief is correct that Enron had a negative effect on PGE's cost of debt, PGE's incremental cost of debt on a portfolio basis should be higher than the market.

Q. Have you analyzed PGE's incremental cost of debt on a portfolio basis?

A. Yes, but only qualitatively by considering how PGE's all-in cost of debt compared to market indices for similarly rated utilities.

Q. Please explain your analysis.

A. In our direct testimony, we provided a comparison of PGE's long-term debt issuances since 2001 to Moody's and S&P's Utility Indices. Pages 88-91 of the work papers accompanying our direct testimony provide the numerical data used for the graphs in PGE Exhibit 1105.

We reproduce the relevant portions below in PGE Exhibit 2014 and compare the indices to PGE's all-in cost for the six issues.

Q. What did you find?

A. As expected, we found that the cost of the six issuances between 2001 and 2003 was either close to the BBB/Baa index or below. In fact, PGE's debt issuance costs at times were lower than the A/Aa issuances. Thus, on a portfolio basis, PGE's incremental long-term debt costs have been below the market for similarly rated issues.

Q. Staff argues that the reason why PGE's bond rating fell was due to the Enron bankruptcy. Do you agree?

A. The Enron bankruptcy was a factor when Moody's and S&P downgraded PGE's secured long-term bonds in Fall 2001. As we discuss below, the effect was primarily on short-term debt because PGE did not issue any long-term debt until October 2002, after we issued the "Golden Share" of preferred stock. Other parties imply that the downgrade was entirely due to Enron's bankruptcy, ignoring the financial and wholesale energy difficulties faced by electric utilities. In addition, we note that during 2001 and 2002, there were 420 downgrade rating actions taken by the three major rating agencies. The more appropriate question is whether PGE would have been able to maintain its debt ratings even if we were not part of Enron.

Q. Would PGE have been able to maintain its bond rating?

A. It is highly unlikely, given the difficult environment faced by electric utilities, especially those in the West. PGE Exhibit 2010 is a January 2003 research report from S&P that discusses the major rating factors when S&P rated PGE BBB+. S&P listed four strengths and four weaknesses, none of which included the Enron bankruptcy. The report states that "PGE is now rated primarily on its stand-alone credit quality."

B. Staff "Corrections" Are Inappropriate

1. Internal Rate of Return

Q. What was Staff's first "correction" to PGE's calculation of long-term debt?

A. Staff's first correction was to recalculate the internal rate of return (IRR) for each of the debt issuances because the internal rate of return calculated by PGE was different than Staff's.

Q. Do you agree with this correction?

A. Not really. The methods used by Staff and by us are slightly different, but the IRR difference is insignificant. Table 3 below shows Staff's and PGE's internal rate of returns for various long-term debt issues. The differences between the IRR calculations are very small, approximately ½ basis point overall. We don't understand why Staff believed it was important to discuss.

Table 3

Internal Rate of Return Calculated by:

Issue	PGE	Staff	**Difference**
MTN 9.31%	9.399%	9.3986%	-0.0004
Notes 7.875%	8.128%	8.1468%	0.0188
PCB Boardman 98A	5.544%	5.5742%	0.0302
PCB Colstrip 98A	5.336%	5.3278%	-0.0082
PCB Colstrip 98B	5.620%	5.6106%	-0.0094
PCB Trojan 85A	5.058%	4.9608%	-0.0972
PCB Trojan 85B	5.046%	4.9534%	-0.0926
PCB Trojan 90A	5.537%	5.5358%	-0.0012
PCB Trojan 90B	7.412%	7.4123%	0.0003
PCB Coyote 96 Float	3.671%	3.6395%	-0.0315

Q. What was Staff's second correction?

A. Staff's second correction concerns PGE's forecasted long-term debt issue in July 2007. Staff contends that the internal rate of return on the debt should be calculated using the end-of-year balance of $100 million rather than the average monthly balance of $54 million and that PGE should use a rate consistent with a 10-year maturity.

Q. Do you agree with Staff's corrections on the cost of debt for the $100 million issue?

A. No. The issuance costs are one-time fees that would be paid when the debt is issued, whether it is January or December. Both Staff and PGE include these fees in the embedded cost of the issue through calculation of an IRR that includes the coupon payments, the issuance costs, and any call premium, if appropriate, from any long-term debt that was redeemed with this bond's proceeds. This embedded rate is then applied to the weighted average amount of the bond outstanding during the year. For example, if the embedded rate is 7% and the $100 million bond is issued in July, then the weighted amount outstanding for the year would be calculated using zero for each month from January through June and $100 million from July through December. Assuming the bond is issued on July 1, the weighted amount outstanding would be $50 million. What Staff did was to use the full amount ($100 million), implying that the bond would be outstanding <u>throughout</u> 2007. Indeed, we expect to issue the bond in July, not January, 2007, leading to a weighted average of $54 million. Staff's "correction" is incorrect and inconsistent with how both Staff and PGE treat outstanding long-term debt.

Q. What maturity does Staff assume for the 2007 $100 million issuance?

A. Although Staff claims that they didn't set a maturity on the 2007 $100 million issue, their calculation for the bond costs reveals that they assume a 10-year maturity on the debt.

Q. Do you agree with this maturity assumption?

A. No. As we stated in our direct testimony, PGE plans to issue 30-year debt, not 10-year. We plan to issue 30-year debt because we want to stagger the maturity dates of our long-term debt and lengthen the average maturity of PGE's debt to more closely match our assets' lives. By staggering the maturity dates, PGE makes strategic financing decisions to ensure significant amounts of debt do not become due at the same time. This avoids potential refinancing liquidity problems, which could lead to higher interest costs. Although Staff states that the "Commission is setting a price for incremental debt, not a maturity schedule" (Staff Exhibit 1200, page 6, lines 16-17), Staff is essentially setting a maturity schedule for future debt issuances through their use of 10-year debt costs. And in doing so, Staff did not take into account PGE's need to stagger its maturity dates as part of an overall financing strategy (Conway Deposition, page 20).

2. PGE 13.5% Redemption in 1988

Q. Why does Staff contend that PGE should not recover its costs related to the 13.5% reacquired debt?

A. Staff argues that PGE should not recover these costs for two main reasons. First, "there is no reliable evidence that customers benefited from the early redemption of the debt securities." (Staff Exhibit 1200, page 4, lines 12-13). Second, Commission policy is to not allow recovery of unamortized debt costs unless the costs are specifically tied to another debt issue.

Q. Do you agree with Staff's position?

A. No. Staff is asking for a cost-effectiveness study that we performed over 18 years ago. We do not keep detailed financial analyses for such a historical period. In spite of the unavailability of the financial analysis, we did explain how the early redemption was cost effective. In PGE's Response to OPUC Data Request No. 190, we explained that "because the rate for debt issued has been less than 13.50% throughout the period since the redemption of this issue, this particular redemption is presumably cost effective." This demonstrates a clear benefit to customers from the early redemption of the debt.

In addition, PGE's 1988 SEC Form 10-K provides additional information regarding the early redemption of the 13½% debt issuance. PGE redeemed the $75 million 13½% FMBs in April 1988 with "short-term" borrowings. PGE was able to avoid issuing new long-term bonds because of our strong cash flow, the liquidation of our investment in marketable securities, and issuing preferred stock. We then used part of these funds to redeem the short-term debt. Given this, it is hard to believe that the early redemption of the $75 million 13½% was not cost effective.

Q. PGE did not use the proceeds from a long-term debt issuance to redeem the $75 million 13½% debt. Should PGE still be able to recover the unamortized debt costs associated with the redeemed debt?

A. Yes. PGE should be allowed to recover all prudently incurred costs associated with its debt issuances and redemptions, including the 13½% issue. At issue here is not whether PGE incurred the associated costs when we issued and redeemed debt. We did. Staff does not dispute this. Staff argues that, because we did not issue long-term debt, we therefore should not be allowed to collect prudently incurred costs, even though customers benefit from our actions. This is not reasonable and represents poor regulatory policy. The logical result of this policy is that utilities will be less inclined to redeem debt when it is cost-effective to do so unless they are able to issue long-term debt at the same time. It may be more cost-effective for the utility to redeem the long-term debt with cash on hand or with short-term debt. But, the utility will not be compensated for its previously incurred costs unless it issues additional long-term debt.

C. PGE's Cost of Debt Is Not Directly Related to Enron

Q. Staff alleges that there was a negative and significant "Enron effect" on PGE's cost of debt from 2001 through 2003. Do you agree?

A. No, not completely. We agree that Enron's bankruptcy did affect PGE's ability to borrow in the markets, but any impact on access to capital was primarily limited to the Fall 2001 through Summer 2002 period. For example, as we noted in our direct testimony, PGE was able to place a 366-day debt issue at favorable rates in December 2001, which was when Enron Corp. filed for bankruptcy. Although PGE's access to the markets was limited during this period, after PGE issued the "Golden Share" of preferred stock in September 2002, its access to the markets returned to normal.

Q. What evidence do you have that supports the "Enron effect" being limited primarily to the short-term debt market and to the Fall 2001 through Summer 2002 period.

A. First, during Fall 2001, PGE had difficulty accessing the short-term debt market but we were able to place a 366-day debt issue, as noted above. In June 2002, we decided to renew a revolver or credit line with several banks. At that time, we were able to secure only a $72 million revolver from three banks. However, just one year later, our request for a $150 million revolver was oversubscribed. By May 2003, any Enron effect on PGE's ability to raise capital in the short-term market had largely evaporated.

Q. So, did any of the "Enron bankruptcy effect" carry over into PGE's long-term bonds?

A. The evidence suggests not. The effect would be very difficult to quantify because there were other factors that influenced the financial markets. It is important to note that the financial and wholesale energy markets for electric utilities deteriorated significantly during the 2001-2003 period. As we discussed in our direct testimony, the average S&P bond rating for electric utilities during this period declined from A- to BBB, in line with PGE's downgrade[2]. Given PGE's exposure to the wholesale energy market, it is surprising that PGE's bond rating did not fall even farther.

The difficult task here is to sort out the "Enron effect" from the financial and wholesale energy markets effects. If the financial and wholesale markets had been normal, then one could conclude that most of the increased debt cost may have been due to Enron's bankruptcy. However, given the significant deterioration of the financial and wholesale energy markets, we would conclude that most of the effect was due to the markets and not Enron's bankruptcy.

Q. Doesn't Staff adjust PGE's issuance costs and coupon rates for long-term debt issued in 2002 and 2003 for an alleged "Enron effect"?

A. Yes. However, as we discuss below, Staff's analysis does not consider the impact of the significant – and unrelated – deterioration of the financial and wholesale energy markets. In addition, Staff does not properly adjust PGE's cost of debt for bond insurance that PGE and other electric utilities bought. Finally, Staff's analysis inappropriately compares PGE to PacifiCorp and NW Natural, implying that these three companies somehow had the same

[2] PGE Exhibit 1104 shows that the three major rating agencies took downgrade actions on 150 utilities in 2001, 279 in 2002, and 216 in 2003. Corresponding upgrade actions during this period were 57 in 2001, 19 in 2002 and 35 in 2003.

level of risk and exposure to the financial and wholesale energy markets during the 2001 through 2003 period.

Q. What were the adjustments Staff made to PGE debt issuances in the 2002-2003 period?

A. Table 4 below lists the proposed adjustments by Staff. In general, Staff proposed adjustments to all six of PGE's debt issuances from January 2002 through August 2003.

Table 4

Month/Year	Issue	Effective All-In Debt Rate	Amount Issued ($000's)	Proposed Adjustment(s)
October 2002	FMB 8.125%	8.421%	$150,000	(see FMBs 6.31% and 6.26%)
October 2002	FMB 5.6675%	7.420%	$100,000	Remove $12 million issuance cost
April 2003	FMB 5.279%	6.434%	$50,000	Remove $4 million issuance cost
August 2003	FMB 5.625%	6.266%	$50,000	Use PacifiCorp as proxy for PGE coupon rate
August 2003	FMB 6.750%	7.220%	$50,000	Use PacifiCorp as proxy for PGE coupon rate
August 2003	FMB 6.875%	7.282%	$50,000	Use PacifiCorp as proxy for PGE coupon rate
April 2006	FMB 6.31%	6.704%	$175,000	Remove $7.74 million call premium
April 2006	FMB 6.26%	6.753%	$100,000	Remove $5.16 million call premium

These adjustments lower PGE's cost of debt from 6.826% to 6.30%. The adjustments can be placed into three categories:

- remove the issuance costs for two issues: the 5.6675% and 5.279% issuances issued October 2002 and April 2003;
- remove the call premium resulting from the May 2006 refunding of the 8.125% series issued October 2002; and
- lower the coupon rate on the August 2003 PGE issue, based on the difference between PacifiCorp's S&P long-term debt rating (A-) and PGE's rating (BBB+).

We discuss each of these proposed adjustments below.

<u>1. FMB 5.6675% and 5.279% Issues (Ambac)</u>

Q. Please explain the Ambac securities.

A. These two securities are two long-term bond issuances that are "insurance wrapped offerings" placed with Ambac. As Staff described in their April 2002 memo (UF 4190, OPUC Order No. 02-477),

> The [PGE] FMBs will be sold by private placement to Ambac Conduit Funding, LLC (Purchaser or Ambac). The Company has indicated that the Purchaser is rated AAA. Ambac will use the proceeds from the sale of its bonds to the public to finance the purchase of the Company's FMBs. Ambac will share with the Company a portion of the difference between the interest rate on its bonds and the rate the Company pays for the FMBs.

Q. What does "insurance wrapped" mean?

A. "Insurance wrapped" bonds occur when insurance companies offer to guarantee payment of interest and principle if the underlying debtor fails to pay. The insurance company, such as Ambac, offers to insure the bonds for a negotiated upfront fee or insurance cost. The bonds are then marketed with a AAA guarantee behind the bonds, which lowers the interest rate because the bonds are sold on the insurer's credit rating. If the "all-in" costs of the bonds, taking into account the coupon rate and insurance costs, are lower than what would be available to the company issuing the bonds, the company will choose to utilize the insurance wrap.

Q. Were PGE's all-in costs for these two securities reasonable?

A. Yes. As noted in Table 4, the all-in costs for the two securities were approximately 7.4% and 6.4%, lower than what PGE would have been able to issue in the market by itself.

Q. Should Staff agree that the all-in costs are reasonable for these two issues?

A. Yes. As Staff notes in their memo from UF 4190 (OPUC Order No. 02-477) regarding the second (5.279%) Ambac issue:

> "*The rates and issuance expenses are within a reasonable range.* The interest rate spreads generally appear to be somewhat high, though given the financial pressures that the Company has faced since the Enron bankruptcy filing, such would be anticipated and are in line with recent Commission financing decisions." *(emphasis added)*

At the time that Staff wrote their memo, Staff agreed that the rates were reasonable and that the spreads were in line with recent Commission financing decisions.

Q. What about the first (5.6675%) Ambac issue in October 2002?

A. Staff's recommendation for this issue (UF 4187, OPUC Order No. 02-292) stated:

> "*The issuance and underwriting costs appear reasonable*, assuming that the final interest rate reflects the strong credit-worthiness that should be afforded Ambac, based on the AAA rating as represented by PGE. Even though the final, all-in cost of debt may be ideally near the 7.5 to 8.0 percent range, there is concern that the all-in cost may be somewhat higher than those approved under recent Commission Orders for similar issues." *(emphasis added)*

Staff agrees that the issuance and underwriting costs appear reasonable. In addition, the actual all-in cost for this first Ambac issue was <u>less</u> than the expected range Staff thought was ideal. And yet, Staff now says that the <u>entire</u> insurance/issuance cost should be removed.

Q. Did Staff make other adjustments to the first Ambac issue?

A. Yes. Staff attempted to re-price the bonds based on spreads from a different period of time for a gas distribution company. Such a re-pricing assumes that PGE could issue long-term debt at the same rates as NW Natural. There are significant differences in the risk profiles of NW Natural and PGE, such as NW Natural's ability to recover nearly all energy cost variations through its PGA mechanism and the absence of a similar mechanism in the case of PGE. Yet, Staff's analysis assumes away all differences. Further, Staff's analysis uses the spreads from January 2003, assuming that these spreads were valid in October 2002.

However, as shown in PGE Exhibit 1105, spreads for A and BBB rated electric utilities narrowed considerably between October 2002 and January 2003.

Q. Staff also states that interest rates were stable at the time between the two issuances (i.e., October 2002 and April 2003). Is this correct?

A. No. The initial Treasuries rates and the rates in April 2003 were fairly close; approximately 5-10 basis points different. However, long-term Treasuries rose in November 2002, fell, rose again in December, and then rose and fell through April 2003. In addition, credit spreads for electric utilities were widest in October and had declined significantly by April 2003, as shown in PGE Exhibit 1105.

Q. Why is it important to consider both benchmark interest rates and spreads?

A. These two components are what make up the coupon rate on a particular bond. Although interest rates may have been "relatively stable" (Staff Exhibit 1200, page 16, line 12), credit spreads were not. Coupon rates therefore would have been different over this time period due to the changes in the different industries and/or in the spreads.

2. FMB 8.125% Call Premium

Q. What adjustment did Staff make to the 8.125% October 2002 debt issue?

A. Technically, Staff made no adjustment because PGE redeemed this issue in April 2006. However, Staff did adjust out the $13 million call premium associated with the early redemption, which would imply that PGE should have issued the 8.125% debt at only 5.456% in October 2002, a very low rate.

Q. Is Staff's adjustment realistic?

A. No. Again, Staff has neglected to consider the significant deterioration of the financial and wholesale energy markets for electric utilities in 2002, as discussed more fully above. As we have shown in our direct testimony, the 8.125% issue was very close to or under the rate received by other Baa/BBB electric utilities. Indeed, other PGE long-term debt issues were even below those issued by Aa/A utilities.

3. August 2003 debt issues (5.625%, 6.750%, and 6.875%)

Q. What adjustments did Staff make to the three August 2003 long-term debt issues?

A. Staff adjusted PGE's actual debt issues by 27½ basis points using a hypothetical comparison with PacifiCorp.

Q. Is it appropriate for Staff to make an adjustment to PGE's debt issuances based on a comparison of a PacifiCorp debt issuance?

A. No.

Q. Please explain.

A. Staff adjusted these three PGE issuances based on the fact that PGE had issued debt one month prior to PacifiCorp at a higher cost. This is an overly simplistic analysis for several reasons. First, interest rates for both Baa and A rated bonds declined by approximately 18 basis points from August 2003 to September 2003, as shown in PGE Exhibit 1105. In particular, 10-year Treasuries fell from 4.45% in August 2003 to 3.96% in September 2003, or approximately 50 basis points. Thus, according to Staff's reasoning, one would expect the PacifiCorp bonds to carry an interest rate at least 50 basis points lower than PGE's issue.

Second, the difference in utility yields (all-in) between Baa and A rated bonds was still fairly volatile during the second half of 2003, increasing from the low teens to 30 basis points between June and August 2003. Staff's analysis did not take into account what effect the volatility might have on investors.

Third, very simply, PacifiCorp is not PGE and PGE is not PacifiCorp. Even if the two companies have the same bond rating, they will likely not have the same interest rate if they issue bonds a month apart. Investors consider several factors, as we have noted in our direct testimony, which may make investment in one company preferable to the other.

Finally, Staff did not consider what, if any, expectations investors had that changed during the August and September 2003 time frame. Clearly, the widening credit spread was caused by something.

Q. Was there an error in Staff's adjustment to the August debt issuances?

A. Yes. Even if we accept Staff's simplistic analysis, their result, when corrected, is so small that it is insignificant. When Staff calculated the difference between PGE and PacifiCorp's coupon rates of 5.45 % and 5.625 %, they used 27½ basis points. However, the difference is actually only 17½ basis points. Seventeen basis points is far less than the change in 10-year Treasuries between August and September.

C. Staff Mischaracterizes the 'Enron Effect'

Q. What evidence does Staff attempt to provide that "PGE's cost of capital and cost of debt was negatively affected by Enron issues"?

A. Staff provides excerpts from several Commission orders in financing dockets from the period October 2001 through May 2003. These orders show that PGE requested increased spreads and was having difficulties apparently due to both the deterioration of the financial and wholesale electric power markets and Enron's bankruptcy. However, Staff focuses only on the Enron bankruptcy as a cause for PGE's financing difficulties and thus gives that factor exclusive weight in their analysis.

Q. What mischaracterizations did Staff make regarding the OPUC Orders and PGE's SEC Form 10-K?

A. First, although Staff cites several Commission orders, PGE did not issue long-term debt under any of these orders, with the exception of OPUC Order Nos. 02-477 and 02-292. In addition, Staff quotes from the Appendix to Order No. 02-292 that we requested the financing through Ambac as an "interim solution." This is, however, Staff's characterization of this transaction and does not appear in PGE's application in UF 4187.

Second, Staff's reference to PGE's SEC Form 10-Ks is misplaced. The excerpt from the 2002 10-K states "PGE has experienced higher interest rates for *commercial paper* and other *short-term borrowings*." (Staff Exhibit 1200, page 14, lines 7-8) (*emphasis added*). As we have already discussed, PGE did have difficulty with short-term debt financings, which eased over time. Nevertheless, the fact remains that short-term debt is not included in PGE's 2007 test year.

D. The Ring Fencing Did Work

Q. Didn't the Commission establish a financial ring fence around PGE at the time of the Enron merger?

A. Yes. Several of the conditions in UM 814 were put in place to fence PGE off financially from Enron in the event that some financial disaster occurred at Enron. These ring-fencing provisions were viewed favorably by the credit rating agencies and did insulate PGE from the financial effects of Enron's bankruptcy. In addition to the ring fencing, PGE issued a "Golden Share" that further insulated PGE from Enron.

1. Ring Fencing

Q. Did Staff comment on the effectiveness of the ring-fencing mechanism?

A. Yes. Staff "concluded the ring fencing implemented by this Commission did not fully insulate PGE from the Enron situation." (Staff Exhibit 1200, page 15, lines 7-8). As we have stated previously, we would agree with Staff in that Enron's bankruptcy affected PGE's ability to access the short-term market and conceivably may have had some effect on PGE's ability to access the long-term debt market. However, PGE was able to issue long-term debt that was comparable in cost to other similarly rated electric utilities that issued comparable size debt at a similar time.

Q. Has Staff previously commented on the ring fencing provisions?

A. Yes. Staff witness Conway made a presentation at the 2004 Society for Utility and Regulatory Financial Analysts meeting regarding Oregon's ring fencing. Interestingly, and in contrast to his statement mentioned above in this proceeding, Mr. Conway notes in his presentation slides that "Oregon has been recognized by rating agencies for <u>successful</u> ring-fencing activities" (*emphasis added*). He additionally quoted Standard & Poor's discussion of credit enhancement that "[t]he two strongest means of insulation are through regulatory or legal barriers" and further notes that "[a]ny action state regulators take that provides support for a utility and/or isolates it…from a parent company will be positive for credit." If Mr. Conway's 2004 presentation is to be believed, there is no basis for Staff's proposed adjustment in this proceeding. Either the ring-fencing provisions were adequate, and PGE was insulated from the effects of the Enron bankruptcy (and, in turn, no higher financing costs were incurred), or they were not.

<u>2. The Golden Share</u>

Q. Did PGE take any additional measures to insulate itself from the Enron bankruptcy?

A. Yes. OPUC Order No. 02-674 authorized the issuance of one share of preferred stock to a neutral third party, otherwise known as the "Golden Share." As discussed in PGE/1100, Hager-Valach pages 13-14:

> The Golden Share is one share of special preferred stock. It is held by an independent third party, not by PGE or by Enron. The owner of the Golden Share must submit an affirmative vote for PGE to be able to file for voluntary bankruptcy. Also, it provides additional protection to bondholders. This mechanism was beneficial in allowing PGE to more easily obtain financing. The Golden Share provided additional ring-fencing assurance to Standard and Poor's and other rating agencies, helping to insulate PGE from the effects of Enron's bankruptcy and to stabilize PGE's credit ratings. As a result of this and other factors, PGE was able to issue long-term debt at competitive rates.

E. Conclusions on PGE's Long-Term Debt

Q. What conclusions do you have regarding PGE's long-term cost of debt?

A. We conclude that Staff's "Enron Effect" was minimal, given the volatility of the financial and wholesale energy markets. We also conclude that Staff's corrections to PGE's long-term debt are inappropriate.

IV. Overall Concerns Regarding Staff's Cost of Capital Analysis

Q. What are your overall concerns with Staff's analysis regarding PGE's cost of capital?

A. Our discussion of Staff's cost of capital analysis covers two major areas:

- First, Staff's results are extreme when compared with recently determined ROEs from around the country and with the ROE decisions from the Commission.
- Second, Staff's ROE analysis relies on a single methodology – the DCF – and, in applying that methodology, Staff committed numerous errors in theory and application. Our testimony discusses nine such errors.

A. Staff's Results Are Unreasonably Low

Q. Why do you consider Staff's cost of capital results to be unreasonably low?

A. Staff's cost of capital results can be shown to be unreasonably low for several reasons. First, they would fail to preserve PGE's financial integrity. Using Staff's recommended capital structure, cost of debt, and required return on equity, we find that PGE's financial ratios would be towards the bottom of Standard & Poor's (S&P's) benchmark guidelines for a "BBB+"-rated utility. Second, Staff's recommended 48.5% equity ratio removes significant flexibility from PGE's financing options. Further, in the event PGE suffers earnings losses or other financial setbacks, PGE would likely fall below the Commission's required 48% equity ratio. Third, Staff's recommended required return on equity is lower than any of its recommendations in the last 18 months, although interest rates have, in general, been rising during the period. Staff clearly failed to consider the return required by enterprises with corresponding risks, for Staff's recommended return would place PGE far below the ROEs found necessary for investors in the electric utility industry.

1. Staff's Recommendations Push PGE Closer to Non-Investment Grade

Q. Did Staff calculate the effect of its recommendations on capital structure and ROE for PGE on PGE's financial ratios?

A. No.

Q. Should they have calculated these ratios?

A. Yes. PGE calculated these ratios when it forecasted its 2007 test year and they were supplied as part of our work papers. Normally, if there are small adjustments to the test year, one does not necessarily need to recalculate the ratios. However, given the magnitude of Staff's recommended reductions in PGE's equity ratio and required ROE, it is necessary to recalculate the S&P ratios to determine if the recommendations allow PGE to maintain its financial integrity and ability to attract capital on reasonable terms.

Q. Did Mr. Gorman recalculate PGE's financial ratios using his recommendations?

A. Yes, he did.

Q. Why are PGE's financial ratios important?

A. Credit rating agencies use these financial ratios when performing their bond analyses. For example, S&P uses its benchmark ratios as a basis to determine the bond ratings of companies. If these ratios change significantly as a result of a regulatory decision, then S&P has reason to look at the new ratios and determine if there is a need to change a company's bond rating.

Q. Do credit rating agencies publish their benchmark financial ratios for utilities?

A. S&P is the only one of the three major credit rating agencies that publishes its financial ratio benchmarks. Hence, our analysis focuses on the S&P guidelines even though we have discussed our financial ratios and numbers with all three of the credit rating agencies.

Q. Could the capital structure and ROE recommended by Staff affect PGE's bond rating?

A. Conceivably, yes. PGE's business profile from S&P is "5." One of the benchmarks used is "Total Debt/Total Capital." For a "BBB"-rated utility, this should be between 50%-60% (Staff Exhibit 1003, page 128). For an "A"-rated utility this ratio should be between 42%-50%. PGE is rated BBB+ by S&P which implies that its debt ratio should be between 50% and 53%.

Q. What is Staff's recommended capital structure?

A. Staff recommends 48.50% equity and 51.50% debt. This debt calculation, however, does not take account of the use of "debt equivalents," or imputed debt, by S&P in its analysis.

Q. Does Staff consider imputed debt when recommending its capital structure for PGE?

A. No. In fact, Mr. Morgan states that he is not familiar with the fact that S&P requires a greater amount of equity on a company's balance sheet to offset the effect of imputed debt (Morgan Deposition, p. 55, lines 5-9).

Q. What is imputed debt?

A. For electric utilities, imputed debt is primarily related to purchased power obligations. The credit rating agencies calculate an additional amount of "imputed" debt that they then add to the company's actual debt and recalculate the financial ratios. The credit rating agencies consider these ratios when they evaluate a company's bond rating.

Q. What is the effect of imputed debt on the credit rating agencies' evaluation of PGE?

A. The amount of imputed debt from long-term purchased power contracts and operating leases in 2007 is projected to be approximately $250 million. This adds approximately 5.6% of additional debt to PGE's balance sheet.

Q. Did you calculate the financial ratios using Staff's recommendations?

A. Yes. We found that Staff's recommendations, if adopted, would push PGE's financial ratios to the edge of the BBB+ range and closer to a rating downgrade.

Q. How did you determine that Staff's recommendations would push PGE's financial ratios closer to a downgrade?

A. We updated our financial model to include Staff's recommended required return on equity, cost of debt, and capital structure. We also included the changes in expenses due to the stipulations regarding O&M/A&G and the depreciation study (UM 1233). We then ran the financial model for 2007. We also ran our financial model with our recommended cost of capital and included the two stipulations. Our results are shown in PGE Exhibit 2015. Table 5 below reproduces the S&P financial ratios for both 2007 results as well as S&P's benchmark guidelines for a "BBB"-rated utility with a business profile of "5".

Table 5
S&P Financial Ratios Using Staff & PGE Recommendations
(Before Imputed Debt)

Ratio	S&P Benchmark	2007 Forecast Using PGE CoC	Staff CoC
Total Debt/Total Capital	60%-50%	44.64%	45.72%
FFO/Interest Coverage	2.8-3.8	4.70	4.31
FFO/Average Total Debt	15.0-22.0	25.76	22.89

If we add the imputed debt to the capital structure, PGE's debt ratio would be over 50% on an actuals basis. If we use Staff's recommended debt ratio of 51.5%, PGE would have a debt ratio of 57.1%, close to BBB- range.

2. Staff's Recommended Capital Structure Would Limit PGE's Flexibility

Q. Do you agree with Staff's recommendation that PGE's capital structure be set for ratemaking purposes at 48.5% common equity and 51.5% long-term debt?

A. No. If the Commission adopts Staff's recommendation, then the Commission has told us that the appropriate capital structure is one with 48.5% common equity. PGE would have a disincentive to maintain an equity ratio above this level. If PGE did maintain its equity ratio above 48.5%, we would fail to recover the capital costs associated with a higher equity ratio. So, we would have an incentive to reduce our equity ratio to this level sooner rather than later.

Q. Staff states that "if PGE employs less debt and more equity in its capital structure than the sample companies …, all else equal, PGE is a less risky investment than suggested by the model." Do you agree with Staff's conclusion?

A. Yes, all else being equal. But Staff has dismissed the reasons why PGE is not a less risky investment. As we discussed in our direct testimony, we believe we need to maintain the higher equity ratio for several reasons, including:

business reasons, which include that the equity will enable PGE to:

- maintain its financial strength, flexibility, and adequate liquidity,
- maintain reliable and economical access to the capital markets,
- minimize the overall cost of capital to customers and shareholders, and
- offset debt equivalence of purchased power contracts.

<u>specific circumstances</u>, which include that:

- we must comply with Condition 5 of OPUC Order No. 05-1250, which requires PGE to maintain an equity capital ratio of at least 48%, and Condition 6(c) of the same Order, which requires PGE to maintain at least $40 million in additional equity beyond the 48% until 30 days after the tariffs for the next general rate case are approved.
- PGE must be able to maintain liquidity for unexpected margin calls as wholesale prices fluctuate and for unresolved issues including litigation and SB 408.
- PGE has high capital expenditures associated with hydro relicensing, beginning in 2007 and increasing in the following years.
- PGE is exploring new wind ownership or purchase in the near future and has proposed an AMI (advanced metering infrastructure) system.
- PGE must be able to offer assurance to its equity and bond investors of sufficient cash flow, including sufficient equity to offset debt equivalence imputed by credit rating agencies.
- The regulated capital structure does not include our current short-term debt or revolvers, which we have reduced since 2001.

To these we would add one more reason for our higher equity ratio: PGE must be able to maintain an investment grade unsecured bond rating to cost effectively access wholesale energy markets.

Q. Have any of these reasons or circumstances changed since the filing of direct testimony?

A. No. In fact, the current status of SB 408 and the recent State Supreme Court ruling, as discussed above, provide further reasons for PGE to maintain a higher equity ratio.

Q. Are there additional reasons that PGE is not a less risky investment?

A. Yes, there are several. First, PGE does not have a power cost adjustment (PCA) mechanism. As noted in our direct testimony, our recommended RROE assumes that the NVPC regulatory framework that Ms. Lesh and Mr. Niman proposed, which includes a PCA, will be adopted. Without a PCA, PGE would indeed be more risky. Second, PGE needs the additional equity to maintain its access to the short-term energy markets in the event that we must supply collateral for our purchases.

Q. Do you agree with Staff's statement that "[a]ssuming a capital structure that is different than the Company's actual capital structure does not impact the ability of the Company to manage its capital structure?"

A. No. We would agree that the regulated capital structure will most likely be different from a company's actual structure, given regulatory lag. However, the capital structure determined by the Commission essentially tells the company what the Commission wants the company's capital structure to be. By imposing a 48.5% equity ratio, the Commission would be telling PGE that it would be prudent to allow its equity ratio to decline to this level because PGE will not be compensated for any amount above this level. Such a decision would also signal to investors that the Commission will not compensate for the risks that PGE has identified and therefore, investors would be less likely to purchase securities from PGE. Thus, Staff's suggestion that PGE would not be harmed by such a low equity ratio is incorrect.

Q. Does Staff's recommended capital structure reduce PGE's financing flexibility?

A. Yes. If PGE reduces its equity ratio to Staff's recommended level, then we would not be able to issue long-term debt with as much flexibility as we currently have. In order to maintain the 48.5% equity ratio, we would essentially have to issue equal amounts of common stock and long-term debt. Any common stock issuances above the 48.5% equity ratio would fail to be compensated at the required return. If we issue just long-term debt, our equity ratio would fall below the required 48% threshold.

3. Staff's Recommended Required Return on Equity Is Extremely Low

Q. Staff's recommended RROE is 9.3%. How does their recommendation compare to what investors have seen adopted during the last 18 months?

A. Staff's recommended RROE is significantly lower than any adopted authorized ROE by a state regulatory commission over the last 18 months, as shown in PGE Exhibit 2005.

Q. What impact would Staff's recommended RROE have upon investors?

A. All else equal, investors would likely purchase securities of other electric utilities since they have higher authorized ROEs, especially given the significant 30-45 basis points minimum difference between Staff's recommendation and those adopted elsewhere. Thus, if PGE issued common stock, it would have to do so at a lower price than otherwise, causing it to issue more common stock and potentially pay increased dividends in order to maintain its relative attractiveness to investors.

B. Staff's ROE Analysis Is Narrow and Contains Numerous Errors in Theory and Application

Q. What issues or concerns do you have with Staff's ROE analysis?

A. We have numerous issues with respect to Staff's ROE analysis, including the following:

- Staff only uses one method, the DCF model, to evaluate PGE's required ROE.
- Staff made no reference to the standards of setting just and reasonable rates required by *Hope, Bluefield*, and ORS 756.040.
- Staff did not follow their own criteria in the selection process for their sample group of companies.
- After performing their DCF analysis on their sample group of companies, Staff failed to make any adjustments to reflect PGE-specific risks.
- Staff considers only Oregon regulatory decisions and policy and does not attempt to evaluate its analysis alongside those used in other regulatory environments.
- Staff's DCF analysis inappropriately relies upon a one-day spot price to calculate the dividend yield component.
- Staff repeatedly refers to "evidence" that they relied on in their analysis but when asked to produce that evidence, Staff responded that in most cases the "evidence" consisted of either their judgment or their own expertise.
- Staff failed to consider the capital structure requirements imposed by existing Commission orders.
- Although Staff claimed to reject use of historical GDP growth rates in the DCF model, they consider historical growth rates in their analysis.
- Staff incorrectly evaluates the impact of institutional ownership in their DCF analysis.

1. Use of One Method to Determine Cost of Equity

Q. Staff uses only one method to calculate PGE's required ROE. Do other regulatory commissions use just a single method?

A. No. Most state commissions consider two or more methods. PGE Exhibit 2011 is a summary of a 2001-2002 survey PGE performed regarding the various methods used by state regulatory commissions to determine required ROEs for companies within their jurisdiction[4]. At that time, most regulatory commissions were using both a DCF model and a risk premium model, which would include CAPM. Different commissions used different forms of the DCF and risk premium models, but the majority used more than one method to determine a company's required ROE.

Q. Is there a potential problem with using just one method to estimate required ROE?

A. Yes. As Dr. Roger Morin notes in his text,

> "It is dangerous and inappropriate to rely on only one methodology in determining the cost of equity. For instance, by relying solely on the DCF model at a time when the fundamental assumptions underlying the DCF model are tenuous, a regulatory body greatly limits its flexibility and increases the risk of authorizing unreasonable rates of return. The results from one method are likely to contain a high degree of measurement error. The regulator's hands should not be bound to one methodology of estimated equity costs, nor should the regulator ignore relevant evidence and back itself into a corner."
>
> (Morin, Roger A., Regulatory Finance, Public Utilities Reports, Inc., 1994 page 28).

One should not rely solely on the results of one financial model. Doing so ignores the real world and financial theory that has been formalized in risk premium models. Dr. Zepp

[4] PGE is in the process of updating the survey. The survey is not complete but our results, as of August 31, are included in our work papers.

discusses this issue further in his rebuttal testimony, and offers additional methodologies for the Commission's consideration.

Q. Are you suggesting that the fundamental assumptions underlying the DCF model may be "tenuous," as referred to in Dr. Morin's book referenced above?

A. No, we would not say the fundamental assumptions are necessarily "tenuous" given the circumstances of the current economic and financial environment. These circumstances do suggest, however, that the DCF results should be corroborated with the results produced by other methodologies. We have not performed an analysis on the DCF assumptions, but questions with the DCF model arise when (1) regulatory commissions are authorizing ROEs in a range (10%-11%) which exceeds the range produced by sole reliance on the DCF model, and (2) other methods yield a much higher result. In other words, the difference between the DCF estimates and other methods is quite significant, and it would appear that other regulatory commissions have placed less emphasis on the DCF results.

2. Standards of *Hope, Bluefield*, and ORS 756.040

Q. The Oregon Public Utility Commission is charged with setting just and reasonable rates for utilities based on the standards set forth in *Hope, Bluefield*, and ORS 756.040. Were any of these standards addressed in Staff's testimony or exhibits?

A. No, at least not directly. Nowhere in Staff testimony is there any reference to the Constitutional standards or the governing Oregon statute. (Staff Exhibit 1003, page 34 includes a quote from *Bluefield*, but the cited excerpt focuses on a very limited aspect of the constitutional requirement.)

Q. What are the standards set forth under those three authorities?

A. *Bluefield* established the principle that a utility is entitled to earn a return comparable to that earned by companies with similar risks and uncertainties, generally referred to as the "comparable earnings" requirement (*Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, 1923). In the *Hope* decision, the Supreme Court confirmed the principles established in *Bluefield*, and added "financial integrity" and "capital attraction" requirements (*Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 1944). From these two cases, three "tests" emerged to assess the reasonableness of allowed return: (1) the standard of capital attraction (2) the standard of comparable earnings and (3) allowance of the utility to maintain financial integrity. Under the standards of *Hope*, "the return on equity must be commensurate with returns on investments in other enterprises having corresponding risks" (*Id.*).

Q. What do these decisions imply regarding regulation?

A. The regulatory principles from these decisions indicate that rates should be based on prudently incurred costs of service and those costs of service include a fair rate of return and recovery of investments made to provide regulated service. The regulatory bargain between utilities and commissions depends on investors having a reasonable opportunity to earn a fair rate of return.

Q. Has the State of Oregon provided any guidelines regarding cost of capital?

A. Yes. ORS 756.040 reflects the principles in the *Hope* and *Bluefield* decisions. It states, in part:

> The commission shall balance the interests of the utility investor and the consumer in establishing fair and reasonable rates. Rates are fair and reasonable for the purposes of this subsection if the rates provide adequate revenue both for operating expenses of the public utility or telecommunications utility and for capital costs of the utility, with a return to the equity holder that is:

> a. Commensurate with the return on investments in other enterprises having corresponding risks; and
> b. Sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital.

Q. What are the implications on Staff's recommended cost of equity for PGE by not considering these standards?

A. Staff's testimony contains no analysis which indicates how these requirements have been satisfied under Staff's recommendations. Without this analysis, Staff cannot represent that its recommended cost of equity for PGE would allow PGE to have a reasonable opportunity to earn a fair rate of return based on a comparison of PGE to other companies having corresponding risks.

3. Problems with the Selection Process for Staff's Sample Group of Companies

Q. How did Staff select its PGE comparable sample?

A. Staff claimed that they used a three-step process. First, they excluded companies that have "a large amount of revenues, assets, or earnings focused on unregulated operations." Second, they selected companies that were rated by S&P as BBB or higher. Third, they used "final judgment pertaining to the anticipated future state of the companies' business."

Q. Did Staff follow their own criteria during their selection process?

A. No. It appears that Staff included companies with large amounts of revenues from unregulated operations and they used bond ratings for the holding company instead of the appropriate utility operating company.

We asked Staff to define what "a large amount of revenues, assets, or earnings" meant. Staff's response was that large "refers to an amount that would have limited a company's usefulness as a proxy to apply to PGE's rate-regulated property." In other words, Staff used their judgment to determine what "large" meant. We note that Staff included WPS Resources, which has 78% of its revenues from unregulated and other operations (Staff Exhibit 1003, page 111). To us, this proportion of non-utility revenues would seem to warrant the exclusion of WPS Resources.

We examined the S&P bond ratings put forth by Staff for its 14-company sample. We found that Empire District Electric was downgraded to BBB- May 17, 2006 and therefore, Empire District Electric should not be in the Staff sample.

Q. Are there other problems with Staff's sample selection process?

A. Yes, there are several additional problems with Staff's sample selection process.

- As discussed in Dr. Zepp's testimony, Staff's sample selection process resulted in a sample group of companies that has a less riskier business profile than PGE (a business profile of 3.9 versus PGE's 5.0).
- As discussed in Dr. Zepp's testimony, Staff's sample selection process resulted in a sample group of companies that has an average bond rating that is higher than PGE's ("A" versus PGE's "BBB+").
- As discussed in Dr. Zepp's testimony, Staff's sample selection process resulted in a sample group of companies that purchases only 35% of its power, versus PGE's 49% reliance on purchased power. Staff did not consider the percentage of purchased power a company may have in developing their sample group of companies (Morgan Deposition, p. 35, lines 18-24). The level of purchased power will indicate how "long" or "short" a utility may be, and thus the level of risk of variable power costs. The greater reliance on purchased power and exposure to the wholesale energy market, the more risky a utility can be.

- As discussed in Dr. Zepp's testimony, Staff did not consider the impact of a utility cutting its dividend when they developed their sample group of companies (Morgan Deposition, p. 32, lines 1-6). This is an important factor to consider in sample selection because dividend cuts can reduce the attractiveness of a utility and reduce its share price. These two factors, a lower dividend and lower share price, when using the DCF model, result in lower growth rates.
- Staff did not consider other commonly used financial filters such as earnings volatility, ROE volatility, and the stability of dividends or growth (See *generally* Morin pp. 201-230). Staff did not consider earnings or dividend growth (OPUC Response to PGE Data Request No. 033). By including companies that have negative earnings and/or dividend growth, Staff biases the growth average downward. They assume that rational investors would purchase stock in companies whose growth is expected to be negative. It is unreasonable for an investor to expect negative earnings growth in the long term.
- Staff's sample group includes three utility companies that operate in deregulated environments, which essentially means they are transmission and distribution (or "poles and wires") only companies and are not subject to purchase power and generation risk. Staff did not consider the differing risk profiles of transmission and distribution only companies versus vertically integrated companies in developing their sample group (Morgan Deposition, p. 32, lines 20-25). These transmission and distribution companies tend to experience little, if any, power supply or purchased power risk. Thus, they are inherently less risky and have lower required ROEs. Including these companies as

comparables reduces the overall required ROE estimate. In fact, Mr. Morgan acknowledged that "the risk profile is likely different" between a vertically integrated utility and a transmission and distribution only company (Morgan Deposition, p. 32, lines 23-24).

Q. According to the above discussion, is Staff's sample representative for PGE in terms of choosing companies that have commensurate risks?

A. No. From the points set out above, it is evident that Staff did not consider several risk factors when determining the sample for its analysis for the recommended ROE for PGE.

Q. What are the implications of choosing a sample that does not consider risks commensurate with PGE in determining PGE's ROE?

A. This gives Staff an invalid starting point in its DCF analysis. The error is compounded by Staff's failure, after performing a DCF calculation for their sample group of companies, to address PGE-specific risks, as discussed in the following section.

4. Staff failed to make any adjustments to reflect PGE-specific risks following their DCF analysis of the sample group of companies.

Q. Following Staff's DCF analysis of their sample group of companies, did they make any adjustment for PGE-specific risks that would not have been reflected in the analysis of the sample group?

A. Staff's testimony contains no such analysis. In particular:

- Staff did not consider whether it would be appropriate to take account of the fact that unlike many of the companies in Staff's sample group, PGE does not have a power cost recovery mechanism. It is well accepted that having a power cost recovery mechanism reduces a company's risk. Staff included some companies that have a PCA. These are obviously not comparable to PGE since PGE does not currently have a PCA and, if PGE's proposed PCA mechanism is not approved in this proceeding, an upward adjustment would seem to be warranted to Staff's ROE recommendation.

- Staff did not consider whether a different generation mix between companies can create large disparities in cost of equity analysis. For example, a company with 84% coal generation, such as American Electric Power, has less risk than PGE, which has a high reliance on hydroelectric generation and purchased power, both of which can be volatile. Given PGE's reliance on purchased power and hydro generation to a higher degree than Staff's sample group, an upward adjustment to ROE would seem to be warranted.
- Staff did not make an adjustment for the increased risk associated with operating in Oregon's regulatory and legal environment, such as consideration of the impacts of SB 408 (Morgan Deposition, p. 52). As discussed below, Staff's analysis of this issue assumes, without foundation, that the regulatory environment is perceived as favorable.
- Staff did not consider the risk Oregon utilities face in terms of financing construction of necessary generation and not collecting any costs related to such construction until the Commission deems the utility property used and useful (ORS 757.355). Wisconsin, which includes Alliant Energy in Mr. Morgan's sample, for example, allows utilities to file for pre-approval of a new generating facility, which would reduce regulatory risk.

- Staff did not consider the risk PGE faces with respect to operating within the City of Portland, where the City is claiming authority to set PGE's retail rates (PGE Exhibit 1100, page 41) and threatens from time to time to assert its condemnation authority over PGE property within Portland's city limits.

Q. Why did Staff not address PGE specific risks in its analysis of PGE's recommended ROE?

A. Staff relies on Modern Portfolio Theory to justify its recommended ROE.

Q. What is Modern Portfolio Theory?

A. According to Staff, Modern Portfolio Theory "relates to an investment approach whereby investors construct a grouping of investments. The proper portfolio would offer maximum expected returns for a given level of risk tolerance. The theory assumes that investors like investment returns, but dislike the risk, or volatility associated with those returns." (Staff Exhibit 1003, page 31). Staff continues the explanation stating "[investors] can reduce their overall exposure to each investment of 'business specific' risk that would affect them if they were not well diversified." (*Id*.). Generally, this theory states that investors will choose different stocks to create a portfolio that will reduce the diversifiable, or company specific, risks.

Q. Is this an appropriate theory to apply when estimating the required ROE for an individual utility for ratemaking purposes?

A. No. The Modern Portfolio Theory, as applied by Staff in this proceeding, would fail to produce an allowed ROE that meets the constitutional requirements of *Hope* and *Bluefield,* and the statutory standard of ORS 756.040. Under Staff's application of the Modern Portfolio Theory, the risks associated with investing in PGE need not be compensated if investors can simply diversify them away. The effect is to disregard the clear Constitutional and statutory requirements that it is the risks of investing in PGE that must be compensated. The result is that PGE will be granted an inadequate return, and its investors will be punished to the extent these risks are not recognized and compensated.

<u>5. Staff considers only Oregon Regulation</u>

Q. Did Staff consider Oregon's regulatory climate in their testimony?

A. Yes. Staff witness Morgan claims that the regulatory environment in Oregon is "favorable" in that "it responds quickly to changing market conditions that affect its regulated enterprises" (Staff Exhibit 1003, page 35). However, when asked to substantiate the basis for this statement, Mr. Morgan did not supply any work papers or other documents to show that Oregon is rated favorably; he stated only that his belief is based on conversations that he has had with rating agencies. As we note later, Regulatory Research Associates (RRA) recently downgraded Oregon from Average 1 to Average 2, citing the impact of SB 408 in particular (PGE Exhibit 2012).

Q. Does Staff consider the regulatory environment or treatment of utilities in other jurisdictions?

A. No. Staff appears to focus solely on the policy and decisions of the Oregon Public Utility Commission.

Q. Should Staff have considered regulatory climate when selecting their sample?

A. Yes. Investors consider regulatory climate as one of the factors in their decision. Staff agrees that strong regulatory support is viewed favorably in the market; according to Staff Exhibit 1003, page 30:

> "The rating will last as long as rating agencies have confidence in the regulatory climate in which the Company operates."

Notwithstanding this acknowledgement of the importance of regulatory climate on the evaluation by investors, Staff did not consider either the regulatory climate in other jurisdictions or the recent downgrade in Oregon's rating.

Q. What would be the effect on investors if Oregon's regulatory climate declines?

A. All else equal, investors would prefer to purchase and own securities of utilities that operate in, and are regulated by other, more favorable regulatory jurisdictions. Investors would expect companies in these jurisdictions to have less downward earnings volatility. On this point, we refer to the authorities cited by Mr. Morgan on pages 35-36 of Staff Exhibit 1003.

6. Staff's use of spot prices in its DCF analysis

Q. Staff uses one-day spot prices in its DCF analysis. Does either PGE or ICNU-CUB use one-day spot prices?

A. No. Both Dr. Zepp and we use closing or spot prices measured over a period of time. Mr. Gorman, for his part, averages the closing prices over a 13-week period, which is fairly common (ICNU-CUB Exhibit 300, page 17). We all find that one-day spot prices are too volatile and/or inconsistent with other data that we use for estimating a utility's required ROE.

Q. Have recent daily stock prices for electric utilities been volatile?

A. Yes. This is readily apparent by comparing the two dates that Staff selected for its analyses for PacifiCorp (Docket UE 179) and PGE. Staff used the same 14-company sample for both PacifiCorp and PGE in conducting their DCF analyses; the only difference was the time that elapsed between the date Staff used for its analysis in PacifiCorp (June 28) and the date used by Staff for its analysis in this docket (August 8). Between June 28th and August 8th, the stock prices of almost all the electric utilities in Staff's sample rose as shown in PGE Exhibit 2016. Over this six-week period, individual electric utility stock prices rose anywhere from 3.2% to 12.8%. Indeed, during this period, individual stock prices varied from -1.8% to 12.8%, from their closing prices on June 28. Depending on which day Staff chose to perform their DCF analysis, their results for PGE would differ significantly from those for PacifiCorp, which would contradict their belief that both PGE and PacifiCorp have the same risk. Indeed, the run up in stock prices contributed to their 20 basis points lower ROE recommendation for PGE than for PacifiCorp, using the same sample companies.

Q. Staff uses one-day stock prices and once-a-quarter forecasts or estimates in their DCF model. Is it appropriate to mix temporal data in this manner?

A. No, for the reasons discussed in Dr. Zepp's testimony.

Q. Why don't the analyses performed by the Company and by Mr. Gorman suffer from the same deficiency as Staff's?

A. As we noted above, we use a time period, not a spot price, and this time period roughly matches the period over which investors' growth expectations are estimated. We use the high, low, and close over a period of 3-6 months, Dr. Zepp uses high and low stock prices during the previous 3 months and Mr. Gorman averages his stock prices over a 13-week period.

<u>7. Staff's "evidence" is really its judgment</u>

Q. Regarding your fourth concern, Staff makes several references in its testimony and exhibits to "evidence" upon which they relied in making their determination. Did Staff provide such evidence?

A. No. PGE asked several data requests of Staff requesting the evidence or literature upon which they stated that they relied. In most cases, Staff's reply was that they were either unaware of such evidence and therefore could not provide such evidence, or that the evidence consisted solely of Staff's judgment. PGE Exhibit 2023 provides several examples where Staff states in their testimony that they had evidence or supporting documentation when, in fact, they relied on their own judgment. For example, Staff stated that there was "a lot of evidence" that risk premiums may be time varying. However, when PGE asked Staff to produce this evidence, Staff responded that the evidence was "Mr. Morgan's knowledge and was not based on contemporaneous analysis of the literature."

Q. Why is Staff's substitution of their judgment for evidence or literature a concern?

A. By portraying Staff's analysis in this manner, Staff created the misimpression that its analysis was supported by additional documentation or financial literature. By citing evidence, Staff implies that there is third-party support for their statements or conclusions. In fact, though, 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.

8. Staff's failure to consider Commission-imposed capital structure requirements

Q. Did Staff consider Order No. 05-1250 from UF 4218/UM1206 regarding the distribution of PGE's stock?

A. No, it does not appear Staff considered this Order.

Q. Did Staff consider Condition 5 of Order No. 05-1250 requiring PGE to maintain at least 48% equity until at least 60% of PGE stock has been distributed from the Disputed Claims Reserve?

A. No, it does not appear that Staff considered this or made an adjustment for this.

Q. Are there other issues that Staff did not consider?

A. Yes, as mentioned in our direct testimony (PGE Exhibit 1100, page 44), PGE must maintain a higher equity ratio for the reasons mentioned above as well as to support capital expenditures for projects such as wind development and hydro relicensing. Another factor justifying a higher equity ratio is the maintenance of investment grade ratings on our unsecured debt in order to maintain our access to wholesale energy markets. Also there are the possibilities of margin calls on power contracts, which becomes a higher possibility with fluctuating power prices or if PGE were to be downgraded. We must be able to have sufficient liquidity to construct our capital projects as well as provide bond and equity holders sufficient confidence in our cash flow.

Finally, *Hope, Bluefield*, and ORS 756.040 require that a company be granted a sufficient overall return to enable it to maintain its financial integrity and attract capital on reasonable terms. This standard is applicable as well in evaluating the recommended capital structure.

Given the above discussion of PGE's need to maintain a higher equity ratio, Staff's recommendation of 48.5% equity is insufficient.

9. Staff's use of historical GDP growth rates in its DCF analysis

Q. Staff recommends against using historical GDP growth rate as a proxy for determining the terminal growth rate in the DCF model (Staff Exhibit 1000, page 17). Does Staff consider any historical growth rates in its analysis?

A. Yes. In fact, Staff states that "[c]onsistent with Staff's past approach to the DCF method, I viewed past dividend growth" (Staff Exhibit 1000, page 9). In addition, Staff analyzed historical book value growth and historical earnings per share.

Q. What was Staff's estimate of historical growth?

A. Staff states that "[o]ver the past fifteen years, the comparable electric companies have achieved a median growth in book value, earnings per share, and dividends of less than 3.0 percent" (Staff Exhibit 1000, page 13). However, we could not reproduce their estimates. Staff did not provide the full fifteen years in their work papers and provided only 5- and 10-year information in their testimony (Staff Exhibit 1000, pages 15-16).

Q. Do Staff's 5- and 10-year historic growth rate tables support Staff's estimates?

A. Yes. The two tables show that the median historic growth rates were less than 3%. However, we were unable to reproduce the estimates for the 5- and 10-year historical growth rates in their tables. Even if we accept the estimates in their two tables, we would be perplexed as to why an investor would choose to invest in utilities that have shown consistent negative growth, if the investor is using the historic growth rate for "guidance," as Staff recommends. Including such companies would suggest that the investor would inexplicably purchase companies that expect negative growth. Finally, we note that the 5- and 10-year historical growth rates for individual companies range from -12.00% to 9.50%.

<u>10. Staff's incorrect evaluation of the impact of institutional ownership</u>

Q. Staff states that institutional investors make up the "lion's share" of ownership in public utilities. Do you agree that this type of ownership can create "stability" as Staff suggests?

A. No, we do not agree. As Staff notes, the effect of such ownership depends on the type of institution that owns the shares. While "pension" companies may be more stable on average than other investors, they, too, are pursuing total return. Thus, if they perceive that PGE will not receive a fair return, they will sell their investment. In addition, we wouldn't say that mutual fund companies are necessarily more stable. Mutual fund companies are not long-run investors. These funds must report annual returns to their owners and if a utility's shares are not performing, the fund will sell the shares just as readily as any other investor. In addition, "firms" include hedge funds and other highly volatile investment groups, which typically have a high turn over of their stock portfolios, tending to increase volatility.

Q. Is PGE's outstanding stock owned by "large institutional investors"?

A. Yes. Apart from the Disputed Claims Reserve for Enron creditors, we don't know the specifics regarding each of the owners of PGE's outstanding common stock. However, we do know that the largest owner is Harbinger, a hedge fund, which owns approximately 7%. Harbinger's investment in PGE has been discussed for many months among the OPUC, Harbinger, and other parties and is still unresolved. Under ORS 757.511, an entity owning greater than 5% in a utility suggests an ability to exercise substantial influence over the utility, which seems inconsistent with Staff's observations that institutional ownership represents an attractive source of stability for a utility.

V. Specific Rebuttal to Staff's Testimony

Q. What specific areas do you rebut regarding Staff's testimony?

A. We rebut two areas. First, we rebut Staff's criticism regarding the arithmetic historical average. Second, we rebut Staff's analysis of our Risk Positioning model.

A. Arithmetic vs. Geometric Averages

Q. Staff criticizes your use of the historical arithmetic average instead of the geometric average as the appropriate method to use as a forecast. Is the historical arithmetic average the appropriate method to use?

A. Yes. This is an ongoing debate and is not likely to be settled any time soon. It is generally agreed that the geometric annual average provides the most useful measure of growth that occurred over a period in the past. But that is not the issue here. Basically, the important question is which average is the best estimate for the next period – the arithmetic or the geometric? The geometric average considers the average return if you made your investment at the beginning of the historical period and if you held your investment for the entire period and if the returns were exactly the same in each and every year during the period. If any one of these is not valid for your future investment, then the geometric average isn't appropriate.

The arithmetic average considers the average of annual returns over the period and assumes that you hold your investment for one year. In our case, we are trying to forecast the next period's (i.e., next year) return. In this case, the arithmetic average is the appropriate one because we are trying to estimate the average for one year, not for a much longer period.

B. Our Risk Positioning Model Is Correct

<u>1. Staff's theoretical concerns are unfounded.</u>

Q. Staff has several "theoretical" criticisms regarding the Risk Positioning model. Did you evaluate these concerns?

A. Yes, we did. We found that some of Staff's concerns regarding our Risk Positioning model were without any basis. However, where Staff suggested a modification to the model that we could readily perform, we did so and found that our results did not change significantly. Finally, regarding Staff's example using a random number generator, we correct Staff's error and find that their model generates an R^2 of zero, or no correlation, as we would expect.

<u>The Risk Positioning model is common across jurisdictions and witnesses</u>

Q. Staff claims that your model is "unique" to you. Is Staff correct?

A. No. The Risk Positioning model has been used in several jurisdictions, including FERC and Texas. In addition, Dr. Zepp has participated in numerous electric and water utility cases in which he, consumer advocates, and/or other parties presented variations of the model. Finally, Dr. Hadaway, PacifiCorp's witness in UE 179, presented a variant of our Risk Positioning model in his direct testimony, which Staff also called "unique." Thus, the Risk Positioning is not unique with respect to jurisdiction or to witness. Staff is simply incorrect – the model has been used by several witnesses in several jurisdictions.

Q. Are these Risk Positioning or Risk Premium models different?

A. Yes. The models are different just as witnesses use different DCF models. But, to say that the Risk Positioning model is "unique" to us is to say that the DCF model is "unique" to Staff. Neither is true. The model is not unique.

Q. Staff further states that the Risk Positioning model has not been "subjected to peer-review." Are they correct?

A. As we discuss above, the model has been used in several jurisdictions and by several witnesses. However, to our knowledge, the Risk Positioning model has not been submitted to a peer-reviewed journal for publication, if that is what Staff means by "peer-reviewed."

Q. Have Staff's models been submitted for "peer-review"?

A. No. Although other forms of the DCF and Risk Premium models have been discussed and reviewed in the literature, neither Staff's specific models, Mr. Gorman's specific models, nor our specific models have been submitted for peer review.

Q. Staff states that you use authorized ROEs as a surrogate for expected returns. Is this correct?

A. No. The risk positioning model postulates that authorized ROE decisions by regulatory commissions are influenced by interest rates. When interest rates are high, we would expect higher authorized returns, all else equal. Conversely, if interest rates are low, we would expect lower authorized returns. The model does not attempt to estimate expected returns, but rather what investors might expect from a commission for an authorized ROE. The risk premium in this model is the premium investors would expect over 7-year Treasuries to compensate them (in the form of an authorized ROE) for the common equity risk.

Q. Staff alleges that "published risk premium literature" use simple differences and do not rely on regression analysis. Is this true?

A. We asked Staff to provide the evidence supporting this statement and Staff responded that the statement is based on their experience. In other words, Staff has no support for their statement. PGE's model follows standard regression theory and practice.

Q. Staff criticizes your model by stating that risk premiums may be time varying. Is this true?

A. They may or may not. A simple internet search on Google or similar search engine would find numerous articles on the risk premium and whether it is constant over time. The question is unsettled. We recognize that the period we use in our regression analysis is approximately 20 years and that interest rates change significantly over this period. However, our model would capture the changes in risk premiums, albeit not perfectly.

Q. Staff claims that your model is circular and quotes Dr. Morin to support their claim. Is your model circular?

A. No. First, the Risk Positioning model does not tell any commission what authorized ROE to grant any more than the DCF or CAPM or any other model tells the commissions. The models provide guidance, they do not dictate. Thus, all commissions could adopt the Risk Positioning model and still be able to "update ROE" and use current information.

Q. Staff uses a quote from Dr. Morin's book, Regulatory Finance – Utilities Cost of Capital to support their circularity claim. Does the quote support Staff?

A. No. Staff has taken the quote out of context. On page 395 of Dr. Morin's text, he is discussing Comparative Earnings models. Earlier in that section, Dr. Morin explains that the Comparable Earnings model or method "stems from a particular interpretation of the *Hope* language that states that returns are to be defined as book rates of return on equity

(ROE) of other comparable firms." Dr. Morin explains the risk comparability of companies that should be in the Comparable Earnings sample and he states:

> "In defining a population of comparable-risk companies, care must be taken not to include other utilities in the sample, since the rate of return on other utilities depends on the allowed rate of return. The book return on equity for regulated firms is not determined by competitive forces but instead reflects the past actions of regulatory commissions. It would be hopelessly circular to set a fair return based on the past actions of other regulators, much like observing a series of duplicate images in multiple mirrors. The rates of return earned by other regulated utilities may very well have been reasonable under historical conditions, but they are still subject to tests of reasonableness under current and prospective conditions." (Morin, page 395)

In the section that Staff quotes, Dr. Morin is explaining his fifth criteria for sample selection when using the Comparable Earnings method. He explains that the sample should include non-regulated industrials so as to avoid circularity problems. Thus, Staff's quote is valid only for Comparable Earnings models, which neither of us uses.

Q. Staff states that because the model spans the period when "interest rates were the highest in history," that the model would likely have a "lagging effect" and "demonstrate that the average ROE is lower" than what the regression analysis would indicate. Do you agree?

A. No. Staff's argument regarding high interest rate is specious. We use data from 1983 through the present, when interest rates were the highest, lowest, and somewhere in-between. Nevertheless, to address Staff's concerns regarding high inflation and interest rates, we re-estimated our Risk Positioning model using data beginning in 1990. Our results are in PGE Exhibit 2019. We found that our implied ROEs using data from 1990 through 2005 were slightly higher than in our original analysis. In other words, excluding the period of high inflation and interest rates raises the implied ROEs. Based on our analysis, we conclude that the Risk Positioning model is valid for the current financial environment.

Q. Would the model have a "lagging effect"?

A. We're not sure what Staff means by that phrase. The model does postulate that commissioners consider interest rates and we considered both 1-month and 7-month lags to reflect how recent the financial information might be in the commissions decisions. Again, the model is intended to provide only guidance to the commission, and does not attempt to tell the commissions what authorized ROE must be granted.

Q. Staff states that use of interest rates from the 1980s in the Risk Positioning model suggests that those interest rates will recur in the future. Are they correct?

A. No. The model uses data from 1983 through the present and includes appropriate interest rates during that period. The model does not, and cannot, forecast interest rates. Staff has misunderstood the model.

"Omitted variables" is a red herring.

Q. Staff states that the Risk Positioning model does not consider other variables that "may be directly relevant." Are they correct?

A. Perhaps. The Risk Positioning model is very simple. It postulates a relationship between interest rates and authorized ROEs. Other variables such as leverage and overall rate base are not directly included in the model that uses interest rates (as measured by Treasuries). However, to some extent, we would expect that our Corporate Bond Risk Positioning model would include the leverage and overall rate base effects. We note that our simple model includes the most important factor, interest rates, and that our results are quite good for a pooled-cross sectional regression. Our model has the expected signs on our coefficients and significant t-statistics. Finally, our model makes intuitive sense.

Q. Staff states that you omitted the impact of the tax cut enacted in 2003 in the Risk Positioning model. Should you have included such a variable?

A. No. Investors would have included the effect of the tax cut on dividends back in 2003 and possibly before. In fact, a Lehman Brothers report provided in Staff Exhibit 1003, page 177 published June 4, 2003 states they "believe the enacted dividend tax reduction is now fully incorporated into utility valuations." We agree with Staff that the tax cut might have affected required returns and this effect, if any, would already be included in our regression. However, Staff did not quantify how much of an impact this might have on common stock prices.

2. The Risk Positioning Model is correctly specified.

Q. Staff alleges that your risk premium model is misspecified. Are they correct?

A. By misspecified, we presume Staff is referring to omitted variables. Our answer is no. Staff is under the mistaken belief that any model should contain all possible explanatory factors. As Staff well knows, all models are misspecified, to some degree including the DCF model. The real question is how well does the model explain.

We agree that other factors affect a Commission's determination of any ROE; we did not specify these and do not believe we need to based on the premise of our models. Staff refers to capital structure, rate base disallowances, inflation rates (Staff Exhibit 1000, page 23, lines 24-25), Ballot Measure 9, SB 408, a new wholesale power environment and hydro risks as possible missing relevant variables (Staff Exhibit 1100, page 21, line 22 in reference to Hager-Valach testimony). However, as addressed above, we attempt to find the required historically sustainable risk premium that an investor would expect, given the expected level of Treasuries and/or Corporate Bonds.

Q. Staff claims that omitting variables creates bias. Isn't this a concern?

A. Bias is a concern, but adding variables may create more bias by <u>over</u> specifying the model. The following excerpt sheds light on the omitted variable concern from the view of over-specification.

> "The only thing that can be said for certain is that unless we find ourselves in the precise situation described by textbooks, we cannot know the effect of including an additional relevant variable on the bias of a coefficient of interest. The addition may increase or decrease the bias, and we cannot know for sure which is the case in any particular situation" (<u>The Phantom Menace: Omitted Variable Bias in Econometric Research</u>, Kevin Clarke, 2005).

Therefore, we must show prudence before adding variables to the model at random without a strong theoretical background for such an addition. Staff's suggestion to add several additional explanatory variables indicates a misunderstanding of the purpose and goals of our model.

Q. Did Staff attempt to quantify the alleged bias in your Risk Positioning Model?

A. No. Staff's argument is entirely theoretical. They do not know if adding another factor would reduce or increase the bias.

Q. Did Staff attempt to modify your Risk Positioning model by adding some of their suggested factors as explanatory variables?

A. No.

<u>3. Staff's Analysis Fails to Support Their Critique of the Company's Model.</u>

Q. Staff claims that because you have Treasuries on both sides of your equation, your reasoning is "circular" and the results fallacious. Are Staff's claims correct?

A. No. Staff's claims are incorrect and their analysis using random numbers actually demonstrates the opposite of what they were attempting to show.

Q. Please explain the Risk Positioning model.

A. We began with the simple theory that authorized ROEs are correlated to the interest rate. In order to test this theory, we ran an Ordinary Least Squares (OLS) regression as follows:

$$\text{Authorized ROE} = \alpha + \beta^*(\text{Interest rate proxy}) \qquad (1)$$

The results (available in PGE Exhibit 2017) of this regression showed that β did not equal zero (i.e., a correlation did exist) and that the R^2 value, a generally accepted measure of fit, was high.

However, the purpose of the model was to uncover the long-term or "steady-state" risk premium. The risk premium is the amount in addition to a risk-free rate that investors would expect in a Commission decision regarding authorized ROE. Therefore, we subtracted the interest rate proxy from both sides of the equation. As in basic algebra, this maintains the fortitude of the equation. The result was:

$$(\text{AROE} - \text{Interest rate proxy}) = \alpha + (\beta\text{-}1)^*(\text{Interest rate}) \qquad (2)$$

or simply

$$\text{Risk Premium} = a + b^*(\text{Interest rate}) \qquad (3)$$

We note that in equation (3) above, b = (β-1). This is consistent with the model's findings, as shown in PGE Exhibit 2017 and in work papers.

Q. So, does this mean that either form of the equation could be used to estimate the Risk Positioning model?

A. Yes. In theory, either form could be used. We chose the form in equation (3) because it explicitly models the risk premium.

Q. Have you estimated the other form, that in equation (1)?

A. Yes. Our results show the expected change in the coefficients.

Q. Didn't Staff attempt to show that your model was fallacious by using random numbers instead of authorized ROEs and interest rates?

A. Yes, Staff did produce such a model but the results show the opposite of what Staff concluded.

Q. Please briefly explain Staff's model.

A. Staff regressed two random variables against one another, as well as the difference of two random variables on one of the random variables. Their results in the second regression suggest a correlation and, therefore, they claim that this is evidence that PGE's risk premium model is invalid. Staff's results are shown in Staff Exhibit 1102.

Q. What does Staff's Exhibit 1102 show?

A. Staff Exhibit 1102 purports to show that for the random model estimated using the form in equation (3) above, the results are "highly significant." In other words, the R^2 and R^2-adjusted are significantly above 0, in the range of .45 to .70. However, using the other, equivalent form of the model in equation (1), the results are <u>insignificant</u>, the R^2 and the R^2-adjusted are close to or less than 0. In other words, the results from Staff's first form of the model, show no correlation between the random numbers, which is what we would expect. Thus, Staff has demonstrated that using random numbers in the equation generates no correlation. PGE Exhibit 2018 is a summary of the R^2, showing zero correlation for Staff's random number regression. Our technical appendix demonstrates why the two forms of the equation are interchangeable and explains the different R^2 in Staff's models.

Q. Does Staff's model confirm your Risk Positioning model?

A. Yes. As we discussed above, when we regressed our model using both equations, the end results were exactly the same, although the statistics were different. As shown in PGE Exhibit 2017, our implied ROE is 11.336% for both equations. Both sets of coefficients are significant. This demonstrates not only that there is a correlation between authorized ROEs and interest rates, but that the risk premium form of the model is valid as well.

4. Staff's minor concerns are either irrelevant or easily resolved.

Q. Staff states that they are "troubled" that you did not run "basic statistical tests" to check for common problems in cross-sectional and pooled analysis. Should they be "troubled"?

A. No. Staff is under the mistaken belief that we have a full cross-sectional time series data set. We do not. We have some cross-sectional data, but not for all the jurisdictions in any month. We have some time series data, but not consistently for any jurisdiction. Our data set is a pooled cross-sectional one, but only in the sense that it contains some cross-sectional data and some data over time.

Q. Should you have performed the statistical tests for a cross-sectional analysis?

A. No. There is no logical grouping for the data. We could have performed the appropriate tests for each month, but each month does not have enough data with which to either estimate the model or to perform the test.

Q. Should you have performed the statistical tests for a time series analysis?

A. No. Again, there is no logical grouping for the data. We could have performed such a test for each jurisdiction over time, but each jurisdiction only has a few data points with which we could estimate the model or perform the test. In addition, these data points are not consecutive over the months so the likelihood that there is correlation across the months is extremely low.

Q. Staff is concerned that you were "unable to produce any analysis" to justify your use of a 1-month or 8-month lag. Why were you unable to supply the analysis?

A. We performed the analysis over 7 years ago. We did not believe that we needed to update our analysis. However, to address Staff's concerns, we decided to update our analysis.

Q. What analysis did you use to determine the appropriate lag(s)?

A. We used the Akaike Information Criteria (AIC) and Schwarz/Bayesian Information Criteria (BIC) tests to determine the appropriate lag to use. These tests use a balancing system to determine the appropriate number of variables for a model. While a model with many variables will fit the data extremely well, it has little forecasting use. Conversely, a model with almost no variables has easy forecasting ability but low accuracy. AIC and BIC balance these two effects to maximize a model's usefulness. The measure is inverted: a lower AIC or BIC means a better result.

Q. What were the results of this testing?

A. The results for testing with a single variable were analogous to fitting using R^2 or an adjusted R^2. Since there is only a single variable, the tests will "choose" the variable which best fits the data. Here, a seven-month lag fit the data best, followed closely by an eight-month lag. The results coincide well with our existing theory. We do note that while one-month lag has the lowest R^2, the difference between the one-month and the seven-month models is small.

We also tested for multiple lags, such as a combination of one-and seven-month lags. Using a multiple-lag model, the AIC and BIC results will differ from simply relying on R^2.

However, the downside of models which rely on multiple lags is that for forecasting purposes one must either project all changes (likely by trending) or assume constancy. For our purposes, we adopted the model using lags between one and twelve months which minimized AIC and BIC. We then assumed constant rates on future corporate and treasury bonds in order to estimate ROE. This calculation is shown in our work papers.

Q. Staff questions the accuracy of your entire data set because they found two observations out of nearly 500 that were incorrect. Is this reasonable?

A. No. Staff admits that they only performed a "cursory" review of the data. We don't know if they reviewed any observations other than those for Oregon, although they certainly had the information to do so. Nevertheless, as we noted above, we reviewed the authorized ROE decisions contained in our data set. Like Staff, we found only two observations that required a correction: the two found by Staff for Oregon.

Q. Did your Risk Positioning analysis change when you corrected the two observations?

A. Very slightly. As shown in PGE Exhibit 2019, our estimates for the implied ROE changed at most by one basis point. Correcting the two observations affected the statistics as well by a similar miniscule magnitude.

VI. Specific Rebuttal to Mr. Gorman's Testimony

Q. What is Mr. Gorman's recommendation regarding PGE's capital structure and return on equity?

A. He recommends a 9.9% return on equity with a capital structure consisting of 50% common equity, 49.71% debt and 0.29% preferred stock.

Q. Do you agree with Mr. Gorman's recommendations?

A. No. Although his recommendation for PGE's required return on equity is certainly higher than Staff's recommendation, his RROE and equity ratio recommendations are too low for PGE's current financial environment. We also note that two of his three PGE-specific analyses yielded a required return on equity of 10.4%, far above Staff's recommended 9.3%.

A. Mr. Gorman's Recommended Capital Structure Should be Rejected

Q. Mr. Gorman states that his recommended capital structure will lower the revenue requirement, meet S&P's credit rating financial benchmarks for PGE's current rating, and is more comparable to that of his comparable group. Do you agree with his observations?

A. Yes, in part. Mr. Gorman's recommended capital structure would lower the revenue requirement as would any capital structure that contained more debt than PGE's recommended capital structure, at least in the short term. We would also agree that Mr. Gorman's recommended capital structure might be more comparable to his sample. But, Mr. Gorman has not considered the specific circumstances that lead us to maintain our equity ratio into 2007.

Q. Which specific circumstances cause you to recommend maintaining PGE's current equity ratio into 2007?

A. We listed these circumstances in our direct testimony and summarized them above in Section IV. Mr. Gorman does not believe that PGE needs to maintain an equity ratio higher than his comparable sample, implying that PGE does not have more risk. This is incorrect. For example, PGE's revenue requirement for 2007 is more than 50% net variable power costs. In addition, PGE is required by Commission order to maintain at least 48% equity. And, finally, PGE must maintain its investment grade unsecured rating in order to maintain its access to wholesale energy markets, for unresolved litigation, and SB 408-related issues. Removing the amount of equity that Mr. Gorman suggests would remove the necessary flexibility that is afforded to PGE under its current equity ratio. Indeed, at a 50% long-term debt ratio and a 6% debt imputation due to its purchased power, PGE's debt ratio would reside at 52%, towards the lower end of the BBB+ S&P range.

Q. Mr. Gorman states that the increase in PGE's common equity balance "appears related to Enron's ownership." Do you agree?

A. No. As we stated in our direct testimony, PGE was relieved of its obligation to pay dividends to Enron for a period of time, increasing our liquidity and our common equity and our ability to fund our capital expenditures. However, PGE did pay a $150 million dividend to Enron in 2005. PGE continued with its current common equity level because of the factors that we discussed in our direct testimony, such as the deterioration of the financial and wholesale energy markets for electric utilities. Indeed, PGE's earnings during the 2001-2005 period were substantially below its authorized ROE.

Q. Mr. Gorman states that PGE customers "must be protected from any increase in costs associated with Enron's ownership and bankruptcy." Was there an increase in debt or equity costs as a result of Enron?

A. We discussed this in detail in Section III above. In general, for the period during which Enron owned PGE, we believe the answer is "no." The OPUC required a financial ring-fence around PGE to insulate PGE from Enron. In addition, PGE was able to take advantage of Enron's resources to reduce our costs.

B. Mr. Gorman's Sample Selection

Q. Mr. Gorman lists six criteria that he used when he constructed his sample. Do you agree with his sample selection process?

A. We have no issues with Mr. Gorman's sample selection process. We do, however, disagree with his DCF point estimate of 9.5%. We believe that a range, rather than a point estimate, would have been more appropriate, given PGE's higher risk.

Q. What was the range for Mr. Gorman's comparable sample?

A. The range was 7.38% to 12.58%, which includes the ranges we have for our DCF estimates.

Q. Why do you believe a range would be more appropriate?

A. No sample fully captures the risks associated with PGE. That is, no sample can really represent all of PGE's potential risks, growth, etc. We believe the more appropriate method would be to develop a range, then develop a point estimate based on PGE's unique characteristics compared to the sample.

Q. Do you disagree with Mr. Gorman's range?

A. No.

Q. Mr. Gorman asserts that PGE did not provide any assessment of PGE's risk in relationship to other utilities. Is this correct?

A. No. Mr. Gorman is mistaken. PGE Exhibit 1100, Sections III A and V discuss the business and regulatory risks which PGE faces. These risks are described in those sections and support PGE's need for a higher equity ratio. In addition, we provided PGE Exhibit 1107, which lists different measures of risk for the companies in our three samples, including bond ratings, debt-to-total capital ratios, earnings-to-dividend ratios, average ROE, and the variance in ROE over the previous 5 years.

Q. Mr. Gorman states that you referenced increases in short-term interest rates "in support of a higher return on equity." Is he correct?

A. No. As the question clearly states, our reference on page 17 of our direct testimony was to "financial issues facing utilities today," not return on equity. Mr. Gorman's reference regarding our use of short-term interest rates as a justification for higher required return on equity is incorrect.

Q. Mr. Gorman states that PGE witnesses have "simply failed to properly assess potential changes to return on equity through changes in the market interest rates." Do you agree with this statement?

A. No. First, we again note that his reference to our use of short-term interest rates is incorrect. Second, we did assess long-term, or market, interest rates in our direct testimony. We noted that rising interest rates are a contributing risk to PGE and are one of the factors requiring a higher level of and a required return on common equity.

Q. Mr. Gorman states that the "determination of PGE's cost of capital today should be based primarily on observable and verifiable actual current market costs." Do you agree?

A. Yes, if we were trying to determine PGE's cost of capital today. However, we're trying to determine PGE's cost of capital for the 2007 test year, not 2006.

Q. Mr. Gorman states that his DCF estimates are reasonable given today's "low cost capital market." Do you agree with this?

A. No. As we noted above, we're trying to estimate PGE's cost of capital for 2007, not for 2006. Thus, we disagree that we should be using today's costs to estimate 2007 costs. We use *Global Insight*, a respected financial and economic forecasting group, for our 2007 estimates. We note that the August 2006 *Global Insight* issue projects the 2007 Aa public utility bond yields at 6.81%. This is an increase of 33 basis points since December 2005.

Q. Mr. Gorman suggests that PGE, in its DCF model, assumes high dividend yields in addition to "strong growth projections." Did you explicitly make these assumptions in your DCF model?

A. No. We did not "assume" high dividend yields in our DCF model. Mr. Gorman is referring to "high dividend yields" for the utility industry in general based upon an assumption of high dividend payout ratios. We did not calculate dividend yields for purposes of our DCF modeling. So, whether the dividend yields for PGE's sample companies are "high" is subjective.

Q. Mr. Gorman states that PGE uses "high growth projections," in reference to historical GDP growth, for its long term growth in its DCF model. Why does PGE use historical GDP growth as one of its growth estimates in the DCF model?

A. We used three different types of growth in our DCF model, one of which was historical GDP growth and another was GDP trend growth. Over the long-term, which is centuries long in the DCF model, one does not know whether GNP will continue at its historical growth rate or grow at the trend forecast. We use both historical and trend to help establish our range.

Ibbotson Associates in its 2005 Yearbook, studied returns of large company stocks, small company stocks, long-term corporate bonds, long-term government, intermediate-term government, and U.S. Treasury Bills. They reported both geometric and arithmetic means for the 1926 through 2004 period. The average returns ranged from 7.25% to 8.53%. The results of this study are provided as PGE Exhibit 2009.

C. PGE's Risk Premium/Positioning Models Yield Results Similar to Mr. Gorman's

Q. Mr. Gorman provides a risk premium analysis in the form of CAPM. Do you accept his CAPM analysis?

A. No. Mr. Gorman did not statistically estimate PGE's or any utility's required ROE using a standard CAPM model but rather culled the relevant inputs from various sources and then plugged them into the CAPM equation. Thus, there is no way to statistically verify that his results are appropriate. Further, we do not want to re-litigate the CAPM discussion from UE 115 regarding Beta and CAPM. However, we do note that our risk positioning model is statistically verifiable and that his results are somewhat lower than those we obtained but significantly higher than his DCF estimates, as were our risk positioning results.

Q. Mr. Gorman asserts PGE's risk positioning model should be rejected because you used seven-year Treasury bonds and your results imply a precision that is "flawed and unreliable." Do you agree?

A. No. First, Mr. Gorman's issue with 7-year Treasuries is that he considers them short term rather than long-term. Interestingly, though, he uses 5-year Treasury yields to assess the "reasonableness" of his DCF growth analysis, which is a long-term equity analysis. If 7-year Treasuries are too short for a long-term equity analysis, 5-year Treasuries are definitely too short a term. We did re-estimate our equations using 10-year Treasuries and found similar results.

Second, Mr. Gorman's concern regarding the "precision" implied by the equation is misplaced. We could make the same argument regarding his CAPM or even his DCF estimations – he implies a precision that is "flawed and unreliable." The point is that both models provide an estimate for PGE's required return on equity, from which a range can be derived.

Q. Did you estimate your Risk Positioning model using longer term Treasuries?

A. Yes. To address Mr. Gorman's concerns that we should use longer-term Treasuries, we estimated implied ROEs using 10- and 30-year Treasuries. Our implied ROEs fall by approximately 15 basis points using 10-year Treasuries and 40-45 basis points using 30-year Treasuries. Thus, even using longer term Treasuries, our results are still in the 10.7%-11.2% range.

Q. Mr. Gorman states that your "simplistic" regression analysis ignores the fundamental principle that if inflation expectations decline, interest rates and common equity required returns would also decline. Do you agree?

A. Yes. There is a high correlation between interest rates and inflation expectations. Thus, our risk positioning model includes Mr. Gorman's fundamental principle.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
2001	PGE's Updated Cost of Capital
2002	PGE's Updated DCF Analysis
2003	PGE's Updated Risk Premium Analysis
2004	PGE's Updated Long-term Debt Analysis
2005	Recently Authorized ROEs through August 2006
2006	Different measures of risk
2007	Earning Volatility (Updated NERA study)
2008	Forecasted *Value Line* Equity Ratios
2009	Ibbotson
2010	January 2003 S&P Research Report on PGE
2011	Regulatory Commission Survey on Cost of Equity Estimation Methods
2012	RRA Regulatory Climate Survey
2013	Corrected Staff DCF and Long-Term Debt Estimates
2014	PGE Incremental Long-Term Debt Cost vs. Moody's & S&P's Averages
2015-C	**(Confidential – Provided under separate cover)** S&P Ratios for 2007 using Staff and PGE Recommended Cost of Capital
2016	Utility Stock Prices from June 1, 2006 to August 25, 2006
2017	Equivalence of Risk Positioning Models
2018	Summary R^2 statistics – Staff
2019	Risk Positioning Model - Variations
2020	Staff Responses to PGE Data Requests
2021	Pages from Deposition of Bryan Conway
2022	Pages from Deposition of Thomas Morgan
2023	Examples of Staff's Evidence Being Their Judgement
2024	Updated PGE Samples

APPENDIX A

Risk Positioning

The purpose of this appendix is to offer a mathematical background to support our Risk Positioning model.

Hypothesis testing and coefficients:

Consider the model:

$$[1] \quad Y = \alpha + \beta * X + \varepsilon$$

In order to test whether a correlation exists between Y and X, a "t-test" must be done testing the following set of hypotheses:

Null H_0: $\beta = 0$

Alternative H_1: $\beta \neq 0$

In order to reject the null hypothesis (and thus confirm a correlation), we must use the following test:

$$[2] \quad \frac{\beta}{\text{Standard error of } \beta} = tstatistic$$

To reject the null hypothesis, the t-statistic must be greater than a value predetermined by the number of observations and explanatory variables and the percent confidence you choose. Using a 95% confidence and given our large sample size, our t-statistic generally should be larger than 1.96.

Now consider subtracting X from both sides of equation [1]. Basic algebraic principles state that we can subtract equal values from both sides and maintain the equality. Therefore equation one becomes:

$$[3] \quad Y - X = \alpha + \beta * X + \varepsilon - X$$

Using factoring, this becomes:

[4] $Y - X = \alpha + (\beta - 1)*X + \varepsilon$

Renaming the coefficient on X brings us to:

[5] $Y - X = \alpha + b*X + \varepsilon$

This is the equation estimated in the Risk Positioning model. Note that $b = \beta - 1$, or $b+1 = \beta$.

To test the significance of the explanatory variable in this model, we must still test whether $\beta = 0$. Since $\beta = b + 1$, and we are seeking to test b, we must test the following:

Null Ho: b = -1

Alternative H1: b ≠ -1

The test for this is similar to before:

[6] $$\frac{b-(-1)}{\text{Standard error of } b} = tstatistic$$

Or simply:

[7] $$\frac{b+1}{\text{Standard error of } b} = tstatistic$$

Now, note that $b + 1 = \beta$ from above. Also note that in generating equations [3] through [5], the equality is maintained and thus the standard error does not change. Therefore, equation [7] can be rewritten as:

[8] $$\frac{\beta}{\text{Standard error of } \beta} = tstatistic$$

It is now clear that [8] is the same as [2]. Therefore, one can change the t-test and the two models will remain the same.

Thus we verify our model specification.

Coefficients and Linear Algebra

Consider the model:

[1] $Y = \beta * X + \varepsilon$ footnote 6

where Y is an n-column vector of observations on the dependent (endogenous) variable, X is an n-by-K observation matrix of rank K on the K independent (endogenous) variables, β is a parameter vector, and ε is a disturbance vector.

The least-squares estimator of β is

[2] $b = (X'X)^{-1} X' Y$

which is derived from minimizing the sum of squared residuals—also known as regression by ordinary least squares.

Now consider the modification performed by PGE:

[3] $Y - X = \beta * X + \varepsilon$

Here the estimator for β is, by definition:

[4] $B = (X'X)^{-1} X' (Y - X)$ footnote 7

Algebra allows us to simplify this through distribution:

[5] $B = (X'X)^{-1} X' Y - (X'X)^{-1} (X'X)$

And further:

[6] $B = ((X'X)^{-1} X' Y) - 1$

Thus, it is clear:

$B = b - 1$

This conclusion is supported by empirical evidence. This verifies that the two models differ by a coefficient value, and this value differs from model to model by one.

---

[6] **The simplification of this model which removes the constant term does not affect the outcome; it is merely done to shorten the algebra.**

[7] **Note that the estimator has nominally changed.**

See Griliches, Intriligator. Handbook of Econometrics: Volume 1. North-Holland Publishing Company, New York: 1983

Concerns with R-square values:

The r-square of the two models do not match. How can you say the models are equivalent?

Due to the manner in which R-square is calculated, there is a mismatch.

R-square = 1 – (Sum of Squared Residuals [RSS]) / (Total Sum of Squares [TSS])

Given that:

Total Sum of Squares = Estimated Sum of Squares [ESS] + RSS

The R-square is, in fact:

R-square = 1 – RSS / (ESS + RSS)

The difference between the two models lies in the ESS calculation.

$$ESS = \Sigma\,(y_{estimated} - y_{average})^2$$

where $y_{estimated} = \alpha + \beta * X$

However, ESS is biased due to the method we used. As we showed earlier, the estimated β is off by one as compared between models. Therefore the estimated y values are different and the ESS will differ between models. Therefore, we need a different measure of fit.

Akaike Information Criteria (AIC) is analogous to R-square when applied to single-variable regressions, as seen earlier in testimony page $$. Hence, we can use it as a reasonable proxy for fit. AIC is calculated as follows:

$$AIC = T * \ln(RSS) + 2*K$$

Where T is the number of observations and K is the number of explanatory variables.

The following page demonstrates that, in fact, the two variants of the Risk Positioning model are equivalent from the AIC standpoint.

It can also be seen in workpapers that the residual sum of squares for the two models are equal.

Dependent Variable: Risk Premium

R-Square Selection Method

Number of Observations Read	574
Number of Observations Used	487
Number of Observations with Missing Values	87

Number in Model	R-Square	AIC	Variable in Model
1	0.6099	*-107.4135*	Seven-year Treasuries lagged one month

Dependent Variable: Allowed ROE

R-Square Selection Method

Number of Observations Read	574
Number of Observations Used	487
Number of Observations with Missing Values	87

Number in Model	R-Square	AIC	Variables in Model
1	0.7073	*-107.4135*	Seven-year Treasuries lagged one month

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	$997,280	43.88%	6.83%	3.00%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$1,275,487	56.12%	10.75%	6.03%
Composite Cost of Capital	$2,272,767	100.00%		9.03%

* Represents the Average of the Month End Balances

PGE Multi-Stage DCF Estimates
Terminal Growth: BR+VS

	Combined S&P, Moody's			PGE Comparables			UE 170 Rebuttal PacifiCorp		
	Stock Price			Stock Price			Stock Price		
2006	High	Low	Close	High	Low	Close	High	Low	Close
June	9.87%	10.11%	9.93%	8.73%	8.92%	8.78%	8.74%	8.97%	8.82%
July	9.84%	10.14%	9.89%	8.28%	8.55%	8.32%	8.40%	8.68%	8.45%
August	9.78%	9.99%	9.83%	8.18%	8.37%	8.21%	8.34%	8.55%	8.39%

PGE Multi-Stage DCF Estimates
Terminal Growth: GDP Trend

	Combined S&P, Moody's			PGE Comparables			UE 170 Rebuttal PacifiCorp		
	Stock Price			Stock Price			Stock Price		
2006	High	Low	Close	High	Low	Close	High	Low	Close
June	9.19%	9.47%	9.27%	8.58%	8.83%	8.65%	9.15%	9.43%	9.25%
July	8.99%	9.32%	9.05%	8.36%	8.69%	8.41%	9.00%	9.33%	9.05%
August	8.92%	9.17%	8.99%	8.32%	8.55%	8.36%	8.93%	9.17%	8.99%

PGE Multi-Stage DCF Estimates
Terminal Growth: GDP Historical

	Combined S&P, Moody's			PGE Comparables			UE 170 Rebuttal PacifiCorp		
	Stock Price			Stock Price			Stock Price		
2006	High	Low	Close	High	Low	Close	High	Low	Close
June	11.00%	11.26%	11.06%	10.41%	10.65%	10.48%	10.96%	11.22%	11.05%
July	10.80%	11.12%	10.86%	10.21%	10.52%	10.25%	10.81%	11.12%	10.86%
August	10.74%	10.97%	10.80%	10.16%	10.39%	10.20%	10.74%	10.97%	10.80%

Risk Positioning Method (Data through 7/06)

Using *Global Insight* Forecast*

rate = 5.24

7yr Treasury yields 1983-2006 (1 month lag)

R-Square 0.6095

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.44115	0.13584	62.14	<.0001
yr71	-0.44494	0.01642	-27.11	<.0001

Implied ROE 2007:
11.34966

---

rate = 5.24

7yr Treasury yields 1983-2006 (7 month lag)

R-Square 0.6458

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.16943	0.12469	65.52	<.0001
yr77	-0.42954	0.01461	-29.4	<.0001

Implied ROE 2007:
11.15864

Using August 2006 Interest Rates

rate = 4.83

7yr Treasury yields 1983-2006 (1 month lag)

R-Square 0.6095

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.44115	0.13584	62.14	<.0001
yr71	-0.44494	0.01642	-27.11	<.0001

Implied ROE 2007:
11.12209

---

rate = 4.83

7yr Treasury yields 1983-2006 (7 month lag)

R-Square 0.6458

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.16943	0.12469	65.52	<.0001
yr77	-0.42954	0.01461	-29.4	<.0001

Implied ROE 2007:
10.92475

Using Corporate Bond Rates

		PGE Estimate FMB Bond		rate = 6.75			
		Moody's Baa Utility July 06		rate = 6.61			
Corporate Bonds 1983-2006							
		R-Square	0.6315				

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|		
						Implied ROE 2007:
Intercept	6.43537	0.16851	38.19	<.0001	PGE	10.86965
debtcost	-0.34307	0.01691	-20.28	<.0001	Moodys	10.77768

TOTAL ROE (average) = 11.03375

*Global Insight forecast is an average of 5 and 10-year projected rates for Jan. 2007

Cost of Long-Term Debt

December 31, 2007

(A)	Type (B)	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]
1	FMB	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	10.018%	0.743%
2	FMB	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	5.009%	0.322%
3	FMB	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	5.009%	0.314%
4	FMB	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	5.009%	0.362%
5	FMB	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	5.009%	0.365%
6	Series MTN	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	2.004%	0.188%
7	FMB	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	17.531%	1.175%
7.5	FMB	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	10.018%	0.677%
8	FMB	6.5% Series	15-Jun-07	15-Jun-37	30	6.500%	$54,166,667	$850,000	$0	*19*	$53,316,667	6.565%	98.431%	$54,166,667	$53,316,667	5.426%	0.356%
9	Notes	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	14.952%	1.215%
10	PCB	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	2.364%	0.131%
11	PCB	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	9.797%	0.523%
12	PCB	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	2.104%	0.118%
13	PCB	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	2.024%	0.102%
14	PCB	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	1.673%	0.084%
15	PCB	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	0.962%	0.053%
16	PCB	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	0.511%	0.038%
17	PCB	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	0.581%	0.021%
		Loss on Reacquired Debt							$374,581		($374,581)						
		Total Debt					$998,216,667	$23,595,977	$24,317,169		$950,303,521			$998,216,667	$950,678,102	100.00%	6.789%
		Cost of LT Debt (includes loss from reacquired)															**6.826%**

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 $100 million planned issueance in June 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	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	
Average Monthly Balance	$0	$0	$0	$0	$0	$50,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$54,166,667

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.

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%	
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%	
06/27/2006	Michigan	Upper Peninsula Power	10.75%	Y
		Average	**10.54%**	

* Transmission and Distribution only utilities

Data comes from Regulatory Research Associates

Company Name	Ticker	Tax True-up	PCA	% Puch.	% Coal	% Oil	% Gas	% Nuclear	% Hydro / Other	Finanical Operating Margin %	Fuel Costs % of Revs.	S&P Sec. LT Debt
CH Energy Corp.	CHG	No	Yes - T&D	96%	n.a.	n.a.	n.a.	n.a.	n.a.	12%	69%	n/a
Consolidated Edison, Inc.	ED	No	Yes - T&D	96%	0%	1%	3%	0%	0%	18%		A
Constellation Energy Group Inc.	CEG	No	Yes - T&D	100%	0%	0%	0%	0%	0%	10%		BBB+
Energy East Corporation	EAS	No	Yes - T&D	65%	9%	0%	0%	0%	26%	20%	58%	BBB+
Northeast Utilities	NU	No	Yes - T&D	81%	14%	5%	0%	0%	1%	18%	63%	BBB
NSTAR	NST	No	Yes - T&D	74%	n.a.	n.a.	n.a.	n.a.	n.a.	25%		A+
PEPCO Holdings	POM	No	Yes - T&D	95%	3%	0%	2%	0%	0%	15%	N/A	BBB
PPL Corp	PPL		Yes - T&D	100%	0%	0%	0%	0%	0%	33%	29%	BBB
American Electric Power	AEP	No	Yes	0%	85%	0%	5%	9%	1%	27%	37%	BBB
Cleco	CNL	No	Yes	49%	25%	0%	27%	0%	0%	19%	62%	BBB
DTE Energy Co	DTE	No	Yes	0%	82%	0%	1%	18%	-1%	20%	39%	BBB
Entergy Corp	ETR	No	Yes	26%	10%	1%	14%	48%	0%	26%		BBB
F P L Group Inc.	FPL	No	Yes	15%	4%	12%	29%	15%	25%	24%	52%	A
MGE Energy	MGEE	No	Yes	33%	64%	0%	1%	0%	1%	17%	43%	AA-
NiSource	NI	No	Yes	10%	90%	0%	0%	0%	0%	19%	54%	BBB
OGE Energy	OGE	No	Yes	11%	58%	0%	24%	0%	7%	9%	83%	BBB+
Pinnacle West Capital Corp.	PNW	No	Yes	17%	45%	0%	5%	30%	2%	29%	N/A	BBB-
Puget Sound Energy	PSD	No	Yes	67%	22%	0%	4%	0%	8%	26%	52%	BBB-
Southern Co.	SO	No	Yes	0%	65%	0%	11%	14%	10%	32%	39%	A
Unisource Energy	UNS	No	Yes	0%	99%	0%	0%	0%	0%	28%	45%	n/a
Wisconsin Energy	WEC	No	Yes	3%	68%	0%	0%	27%	2%	25%	43%	BBB+
WPS Resources	WPS	No	Yes	6%	83%	1%	3%	0%	8%	5%	45%	A
Alliant Energy	LNT	No	Yes - WI No - IA	12%	84%	0%	0%	0%	4%	26%	n.r.	BBB+
Avista	AVA	No	Yes - ID Yes - WA No - OR	31%	17%	0%	8%	0%	44%	17%	60%	BB+
FirstEnergy Corp	FE	No	Yes - NJ No - OH	60%	15%	0%	0%	25%	0%	30%	36%	BBB
IDACORP, Inc.	IDA	No	Yes - ID No - OR	9%	49%	0%	0%	0%	41%	26%		BBB+
Vectren	VVC	No	Yes - IN No - OH	0%	99%	0%	1%	0%	1%	18%		A-
Xcel Energy, Inc.	XEL	No	Yes - WI Yes - CO No - NM	3%	64%	0%	17%	17%	0%	20%	53%	BBB
Ameren Corporation	AEE	No	No	0%	87%	0%	0%	10%	2%	28%	44%	BBB+
Empire District Electric Co.	EDE	No	No	25%	51%	0%	22%	0%	1%	27%	43%	BBB-
Portland General Electric	POR	Yes	No	57%	19%	0%	8%	0%	15%	9%	46%	BBB+
Progress Energy	PGN	No	No	0%	43%	7%	10%	30%	10%	22%	43%	BBB
Scana Corp	SCG	No	No	0%	65%	0%	7%	21%	6%	20%	64%	A-
Dominion Resources	D	No	Unknown	16%	42%	0%	5%	32%	5%	22%	58%	BBB

Data Sources:

PCA - Regulatory Research Associates
Generating Sources - Reg. Research. Assc.
Fuel Costs as % of Revenue: ValueLine
Moodys' Secured Long-Term Debt - Operating Company Ratings from Moodys.com
Standard and Poor's Secured Long-Term Debt - Operating Company Ratings for First Mortgage or Secured Debt from standardandpoors.com
n.r. values are not reported by the specified data source
Portland General Electric Oper. Margin and Fuel Cost % come from PGEs 2005 10-K, page #s 21 and 52, respectively

Ratings Key

Moody's Long-Term Rating Definitions:

Moody's long-term obligation ratings are opinions of the relative credit risk of fixed-income obligations with an original maturity of one year or more. They
Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the

Aaa are judged to be of the highest quality, with minimal credit risk.
Aa are judged to be of high quality and are subject to very low credit risk.
A are considered upper-medium grade and are subject to low credit risk.
Baa are subject to moderate credit risk. They are considered medium-grade and as such may possess certain speculative characteristics.
Ba are judged to have speculative elements and are subject to substantial credit risk.
B are considered speculative and are subject to high credit risk.
Caa are judged to be of poor standing and are subject to very high credit risk.
Ca are highly speculative and are likely in, or very near, default, with some prospect of recovery of principal and interest.
C are the lowest rated class of bonds and are typically in default, with little prospect for recovery of principal or interest.

Standard and Poor's Rating Definitions:

Issue credit ratings are based, in varying degrees, on the following considerations:
Likelihood of payment—capacity and willingness of the obligor to meet its financial commitment on an obligation in accordance with the terms of the obligation;
Nature of and provisions of the obligation;
Protection afforded by, and relative position of, the obligation in the event of bankruptcy, reorganization, or other arrangement under the laws of bankruptcy and other
The ratings from 'AA' to 'CCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

AAA - An obligation rated 'AAA' has the highest rating assigned by Standard & Poor's. The obligor's capacity to meet its financial commitment on the obligation is
AA - An obligation rated 'AA' differs from the highest-rated obligations only to a small degree. The obligor's capacity to meet its financial commitment on the
A - An obligation rated 'A' is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-
BBB - An obligation rated 'BBB' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead
BB, B, CCC, CC, and C - Obligations rated 'BB', 'B', 'CCC', 'CC', and 'C' are regarded as having significant speculative characteristics. 'BB' indicates the least degree

Company Name	Ticker	Tax True-up	PCA	% Puch.	% Coal	% Oil	% Gas	% Nuclear	% Hydro / Other	Finanical Operating Margin %	Fuel Costs % of Revs.	Moody's Sec. L-T Debt	S&P Sec. L T Debt
American Electric Power	AEP	No	Yes	0%	85%	0%	5%	9%	1%	27%	37%	A3	A-
Cleco	CNL	No	Yes	49%	25%	0%	27%	0%	0%	19%	62%	A3	
DTE Energy Co	DTE	No	Yes	0%	82%	0%	1%	18%	-1%	20%	39%	A3	BBB+
Entergy Corp	ETR	No	Yes	26%	10%	1%	14%	48%	0%	26%		Baa2	A- / BBB+
CH Energy Corp.	CHG	No	Yes - T&D	96%	n.a.	n.a.	n.a.	n.a.	n.a.	12%	69%		
Consolidated Edison, Inc.	ED	No	Yes - T&D	96%	0%	1%	3%	0%	0%	18%		A1	A
Constellation Energy Group Inc.	CEG	No	Yes - T&D	100%	0%	0%	0%	0%	0%	10%		Baa1	A
Energy East Corporation	EAS	No	Yes - T&D	65%	9%	0%	0%	0%	26%	20%	58%	A3	AAA
Northeast Utilities	NU	No	Yes - T&D	81%	14%	5%	0%	0%	1%	18%	63%		BBB+
NSTAR	NST	No	Yes - T&D	74%	n.a.	n.a.	n.a.	n.a.	n.a.	25%		Baa1	A+
PEPCO Holdings	POM	No	Yes - T&D	95%	3%	0%	2%	0%	0%	15%	N/A	Baa1	BBB+
PPL Corp	PPL		Yes - T&D	100%	0%	0%	0%	0%	0%	33%	29%	A3	AAA
F P L Group Inc.	FPL	No	Yes	15%	4%	12%	29%	15%	25%	24%	52%	Aa3	A
MGE Energy	MGEE	No	Yes	33%	64%	0%	1%	0%	1%	17%	43%	A3	AA
NiSource	NI	No	Yes	10%	90%	0%	0%	0%	0%	19%	54%	Aa2	
OGE Energy	OGE	No	Yes	11%	58%	0%	24%	0%	7%	9%	83%		
Pinnacle West Capital Corp.	PNW	No	Yes	17%	45%	0%	5%	30%	2%	29%	N/A		
Puget Sound Energy	PSD	No	Yes	67%	22%	0%	4%	0%	8%	26%	52%	Baa2	BBB
Southern Co.	SO	No	Yes	0%	65%	0%	11%	14%	10%	32%	39%	A1	BBB-
Unisource Energy	UNS	No	Yes	0%	99%	0%	0%	0%	0%	28%	45%	Baa3	A
Wisconsin Energy	WEC	No	Yes	3%	68%	0%	0%	27%	2%	25%	43%	Aa3	A-
WPS Resources	WPS	No	Yes	6%	83%	1%	3%	0%	8%	5%	45%	Aa2	AA-
Alliant Energy	LNT	No	Yes - WI No - IA	12%	84%	0%	0%	0%	4%	26%	n.r.	A2	A-
Avista	AVA	No	Yes - ID Yes - WA No - OR	31%	17%	0%	8%	0%	44%	17%	60%	Baa3	BBB-
FirstEnergy Corp	FE	No	Yes - NJ No - OH	60%	15%	0%	0%	25%	0%	30%	36%	Aa3	AAA / BBB
IDACORP, Inc.	IDA	No	Yes - ID No - OR	9%	49%	0%	0%	0%	41%	26%		Baa1	A-
Vectren	VVC	No	Yes - IN No - OH	0%	99%	0%	1%	0%	1%	18%		A3	A
Xcel Energy, Inc.	XEL	No	Yes - WI Yes - CO No - NM	3%	64%	0%	17%	17%	0%	20%	53%	A2	A-
Portland General Electric	POR	Yes	No	57%	19%	0%	8%	0%	15%	9%	46%	Baa1	BBB+

Data Sources:

PCA - Regulatory Research Associates

Generating Sources - Reg. Research. Assc.

Fuel Costs as % of Revenue: ValueLine

Moodys' Secured Long-Term Debt - Operating Company Ratings from Moodys.com

Standard and Poor's Secured Long-Term Debt - Operating Company Ratings for First Mortgage or Secured Debt from standardandpoors.com

n.r. values are not reported by the specified data source

Company Name	Ticker	Tax True-up	PCA	% Puch.	% Coal	% Oil	% Gas	% Nuclear	% Hydro / Other	Finanical Operating Margin %	Fuel Costs % of Revs.	Moody's Sec. L-T Debt	S&P Sec. L-T Debt
Ameren Corporation	AEE	No	No	0%	87%	0%	0%	10%	2%	28%	44%	A2	BBB+
Dominion Resources	D	No		16%	42%	0%	5%	32%	5%	22%	58%	A3	AAA
Empire District Electric Co.	EDE	No	No	25%	51%	0%	22%	0%	1%	27%	43%	Baa1	AAA
Portland General Electric	POR	Yes	No	57%	19%	0%	8%	0%	15%	9%	46%	Baa1	BBB+
Progress Energy	PGN	No	No	0%	43%	7%	10%	30%	10%	22%	43%	A3	BBB
Scana Corp	SCG	No	No	0%	65%	0%	7%	21%	6%	20%	64%	A1	

Data Sources:

PCA - Regulatory Research Associates
Generating Sources - Reg. Research. Assc.
Fuel Costs as % of Revenue: ValueLine
Moodys' Secured Long-Term Debt - Operating Company Ratings from Moodys.com

Standard and Poor's Secured Long-Term Debt - Operating Company Ratings for First Mortgage or Secured Debt from standardandpoors.com
n.r. values are not reported by the specified data source

					GENERATION MIX								Corporate Credit Rating	
Holding company name	Subsidiary	Ticker	Tax True-up	PCA	% Puch	Coal	Oil	Gas	Nuclear	Hydro / Other	Operating Margin %	Fuel Costs	Moody's	S&P
Alliant Energy		LNT	No	Yes	12%	84%	0%	0%	0%	4%	26%	n.r.		BBB+
	Interstate Power & Light-IA												A2	BBB+
	Wisconsin Power & Light												A1	A-
Ameren Corporation		AEE	No	No	0%	87%	0%	0%	10%	2%	28%	44%		BBB+
	AmerenIP/Illinois Power												Baa2	n/a
	AmerenUE/Union Electric-MO												A2	n/a
	AmerenUE/Union Electric-IL												A2	n/a
	AmerenCILCO/CILCORP												A2	n/a
American Electric Power		AEP	No	Yes	0%	85%	0%	5%	9%	1%	27%	37%		BBB
	AEP-OH												n/a	n/a
	AEP-TX North												A3	BBB
	AEP-TX Central												Baa1	BBB
	AEP-OK												n/a	n/a
	Indiana Michigan Power												n/a	BBB
	AEP-VA												n/a	n/a
	AEP-WV												n/a	n/a
	Kentucky Power												n/a	BBB
	AEP-LA, AR, TN, MI												n/a	n/a
Avista		AVA	No	Yes - ID Yes - WA No - OR	31%	17%	0%	8%	0%	44%	17%	60%	Baa3	BB+
CH Energy Corp.		CHG	No	Yes - T&D	96%	n.a.	n.a.	n.a.	n.a.	n.a.	12%	69%	n/a	n/a
	Central Hudson Gas and Electric												n/a	A
Cleco		CNL	No	Yes	49%	25%	0%	27%	0%	0%	19%	62%	n/a	BBB
Consolidated Edison, Inc.		ED	No	Yes - T&D	96%	0%	1%	3%	0%	0%	18%		n/a	A
	Consolidated Edison of NY												n/a	A
	Orange and Rockland Util.												n/a	A
Constellation Energy Group Inc.		CEG	No	Yes - T&D	100%	0%	0%	0%	0%	0%	10%		n/a	BBB+
	Baltimore Gas & Electric	BLGH											Baa1	BBB+
Dominion Resources		D	No	Unknown	16%	42%	0%	5%	32%	5%	22%	58%	n/a	BBB
DTE Energy Co		DTE	No	Yes	0%	82%	0%	1%	18%	-1%	20%	39%	n/a	BBB
	Detroit Edison												A3	BBB
Empire District Electric Co.		EDE	No	No	25%	51%	0%	22%	0%	1%	27%	43%	Baa1	BBB-
Energy East Corporation		EAS	No	Yes - T&D	65%	9%	0%	0%	0%	26%	20%	58%	n/a	BBB+
	New York State Elec & Gas												n/a	BBB+
	Rochester Gas & Electric												A3	BBB+
	Central Maine Power												n/a	BBB+
Entergy Corp		ETR	No	Yes	26%	10%	1%	14%	48%	0%	26%		Baa3	BBB
	Entergy-Gulf States_LA												Baa3	BBB
	Entergy-LA												Baa1	BBB
	Entergy-AR												Baa1	BBB
	Entergy-Gulf States_TX												Baa3	BBB
	Entergy-New Orleans												Caa1	D
	Entergy -MS												Baa2	BBB
F P L Group Inc.		FPL	No	Yes	15%	4%	12%	29%	15%	25%	24%	52%	n/a	A

FirstEnergy Corp	FE	No	Yes - NJ No - OH	60%	15%	0%	0%	25%	0%	30%	36%	n/a	BBB
Ohio Edison												Baa1	BBB
Cleveland Electric Illuminating												Baa2	BBB
Toledo Edison												n/a	BBB
Pennsylvania Power												Baa1	BBB
Jersey Central Power & Light												Baa1	BBB
Metropolitan Edison												Baa1	BBB
Pennsylvania Electric												n/a	BBB
IDACORP, Inc.	IDA	No	Yes - ID No - OR	9%	49%	0%	0%	0%	41%	26%		n/a	BBB+
MGE Energy	MGEE	No	Yes	33%	64%	0%	1%	0%	1%	17%	43%	n/a	AA-
NiSource	NI	No	Yes	10%	90%	0%	0%	0%	0%	19%	54%	n/a	BBB
NIPSCO												n/a	n/a
Northeast Utilities	NU	No	Yes - T&D	81%	14%	5%	0%	0%	1%	18%	63%	n/a	BBB
Connecticut Light & Power												A3	BBB
Public Service Company of New Hampshire												A3	BBB
Western Massachusetts Electric Company												n/a	BBB
NSTAR	NST	No	Yes - T&D	74%	n.a.	n.a.	n.a.	n.a.	n.a.	25%		n/a	A+
Boston Edison												n/a	A+
Commonwealth Electric												n/a	A+
Cambridge Electric Light												n/a	A+
OGE Energy	OGE	No	Yes	11%	58%	0%	24%	0%	7%	9%	83%	n/a	BBB+
PEPCO Holdings	POM	No	Yes - T&D	95%	3%	0%	2%	0%	0%	15%	N/A	n/a	BBB
Potomac Electric Power-D.C.												Baa1	BBB
Potomac Electric Power-MD												Baa1	BBB
Atlantic City Electric												A3	BBB
Delmarva Power & Light												Baa1	BBB
Pinnacle West Capital Corp.	PNW	No	Yes	17%	45%	0%	5%	30%	2%	29%	N/A	n/a	BBB-
Arizona Public Service												n/a	BBB-
Portland General Electric	POR	Yes	No	57%	19%	0%	8%	0%	15%	9%	46%	Baa1	BBB+
PPL Corp	PPL		Yes - T&D	100%	0%	0%	0%	0%	0%	33%	29%	n/a	BBB
Progress Energy	PGN	No	No	0%	43%	7%	10%	30%	10%	22%	43%	n/a	BBB
Carolina Power & Light-NC												A3	BBB
Carolina Power & Light-SC												A3	BBB
Floida Power Corp												n/a	BBB
Puget Sound Energy	PSD	No	Yes	67%	22%	0%	4%	0%	8%	26%	52%	Baa2	BBB-
Scana Corp	SCG	No	No	0%	65%	0%	7%	21%	6%	20%	64%	n/a	A-
Southern Co.	SO	No	Yes	0%	65%	0%	11%	14%	10%	32%	39%	n/a	A
Alabama Power												A1	A
Georgia Power												A1	A
Mississippi Power												Aa3	A
Gulf Power												A1	A
Savannah Electric and Power												A1	A
Unisource Energy	UNS	No	No	0%	99%	0%	0%	0%	0%	28%	45%	Baa1	n/a
Vectren	VVC	No	Yes - IN No - OH	0%	99%	0%	1%	0%	1%	18%		n/a	A-
Southern Indiana Gas & Elec												A3	A-
Wisconsin Energy	WEC	No	Yes	3%	68%	0%	0%	27%	2%	25%	43%	n/a	BBB+

Wisconsin Electric Power												Aa3	A-
WPS Resources	WPS	No	Yes	6%	83%	1%	3%	0%	8%	5%	45%	n/a	A
Wisconsin Public Service												Aa2	A+
Upper Penninsula Power												n/a	n/a
Xcel Energy, Inc.	XEL	No	Yes - WI Yes - CO No - NM	3%	64%	0%	17%	17%	0%	20%	53%	na/	BBB
Northern States Power-MN												A2	BBB
Northern States Power-WI												A2	BBB
Northern States Power-ND												n/a	BBB
Northern States Power-SD												n/a	BBB
Public Service Co. Colorado												A3	BBB
Southwestern Public Service-NM												A3	BBB
Southwestern Public Service-TX												A3	BBB

DETAIL PAGE

UE 180 Staff Sample

	Company Name	S&P Bond Rating
LNT	**Alliant Energy**	BBB+
	Interstate Power & Light-IA	BBB+
	Wisconsin Power & Light	A-
AEP	**American Electric Power**	BBB
	AEP-OH	n/a
	AEP-TX North	BBB
	AEP-TX Central	BBB
	AEP-OK	n/a
	Indiana Michigan Power	BBB
	AEP-VA	n/a
	AEP-WV	n/a
	Kentucky Power	BBB
	AEP-LA, AR, TN, MI	n/a
ED	**Consolidated Edison**	A
	Consolidated Edison of New York	A
	Orange and Rockland Utilities	A
EDE	**Empire District Electric**	BBB-
EAS	**Energy East**	BBB+
	New York State Elec & Gas	BBB+
	Rochester Gas & Electric	BBB+
	Central Maine Power	BBB+
IDA	**IDACORP**	BBB+
	Idaho Power	BBB+
MGEE	**MGE Energy**	AA-
	Madison Gas & Electric	AA-
NST	**NSTAR**	A+
	Boston Edison	A+
	Commonwealth Electric	A+
	Cambridge Electric Light	A+
OGE	**OGE Energy**	BBB+
	Oklahoma Gas & Electric Co.	BBB+
PGN	**Progress Energy**	BBB
	Carolina Power & Light-NC	BBB
	Carolina Power & Light-SC	BBB
	Floida Power Corp	BBB
SO	**Southern Company**	A
	Alabama Power	A
	Georgia Power	A
	Mississippi Power	A
	Gulf Power	A
	Savannah Electric and Power	A
WEC	**Wisconsin Energy**	BBB+
	Wisconsin Electric Power	A-
WPS	**WPS Resources**	A
	Wisconsin Public Service	A+
	Upper Penninsula Power	n/a
XEL	**Xcel Energy**	BBB
	Northern States Power-MN	BBB
	Northern States Power-WI	BBB
	Northern States Power-ND	BBB
	Northern States Power-SD	BBB
	Public Service Co. Colorado	BBB
	Southwestern Public Service-NM	BBB
	Southwestern Public Service-TX	BBB

GORMAN SAMPLE

AEE	**Ameren**	BBB+
	AmerenIP/Illinois Power	n/a

	AmerenUE/Union Electric-MO	n/a
	AmerenUE/Union Electric-IL	n/a
	AmerenCILCO/CILCORP	n/a
DTE	**DTE Energy**	BBB
	Detroit Edison	BBB
FE	**FirstEnergy Corp**	BBB
	Ohio Edison	BBB
	Cleveland Electric Illuminating	BBB
	Toledo Edison	BBB
	Pennsylvania Power	BBB
	Jersey Central Power & Light	BBB
	Metropolitan Edison	BBB
	Pennsylvania Electric	BBB
NI	**NiSource**	BBB
	NIPSCO	n/a
POM	**PEPCO Holdings**	BBB
	Potomac Electric Power-D.C.	BBB
	Potomac Electric Power-MD	BBB
	Atlantic City Electric	BBB
	Delmarva Power & Light	BBB
PNW	**Pinnacle West**	BBB-
	Arizona Public Service	BBB-
PSD	**Puget Sound Energy**	BBB-
AVA	**Avista**	BB+
CNL	**CLECO**	BBB
	Cleco Power	BBB
DPL	**D P L Inc.**	BB+
	Dayton Power & Light	BB+
NU	**Northeast Utilities**	BBB
	Connecticut Light & Power	BBB
	Public Service Company of New Ha	BBB
	Western Massachusetts Electric Cc	BBB
OGE	**OGE Energy**	BBB+
	Oklahoma Gas & Electric Co.	BBB+
POM	**PEPCO**	BBB+
	Potomac Electric Power-D.C.	BBB
	Potomac Electric Power-MD	BBB
	Atlantic City Electric	BBB
	Delmarva Power & Light	BBB
PNW	**Pinnacle West Capital Corp.**	BBB-
	Arizona Public Service	BBB-
PSD	**Puget Sound Energy**	BBB-
UNS	**UniSource Energy Corp.**	n/a
	Tuscon Electric Power	BB
WR	**Western Resources**	n/a
	Kansas Gas & Electric	n/a
WEC	**Wisconsin Energy Corp.**	BBB+
	Wisconsin Electric Power	A-
LNT	**Alliant**	BBB+
	Interstate Power & Light-IA	BBB+
	Wisconsin Power & Light	A-
AEE	**Ameren Corporation**	BBB+
	AmerenIP/Illinois Power	n/a
	AmerenUE/Union Electric-MO	n/a
	AmerenUE/Union Electric-IL	n/a
	AmerenCILCO/CILCORP	n/a
CHG	**CH Energy**	n/a
	Central Hudson Gas and Electric	A
CNL	**CLECO**	BBB

ED	**Consolidated Edison**	A
	Consolidated Edison Co. NY Inc.	A
EDE	**Empire District Electric Co.**	BBB-
EAS	**Energy East Corp.**	BBB+
	New York State Elec & Gas	BBB+
	Rochester Gas & Electric	BBB+
	Central Maine Power	BBB+
ETR	**Entergy Corp**	BBB
	Entergy-Gulf States_LA	BBB
	Entergy-LA	BBB
	Entergy-AR	BBB
	Entergy-Gulf States_TX	BBB
	Entergy-New Orleans	D
	Entergy -MS	BBB
EXC	**Exelon Corp.**	BBB+
	PECO	n/a
	Commonwealth Edison	BBB+
FPL	**F P L Group Inc.**	A
	Florida Power & Light	A
SCG	**Scana Corp**	A-
	South Carolina Elec & Gas	A-
VVC	**Vectren**	A-
	Southern Indiana Gas & Elec	A-

DRAFT

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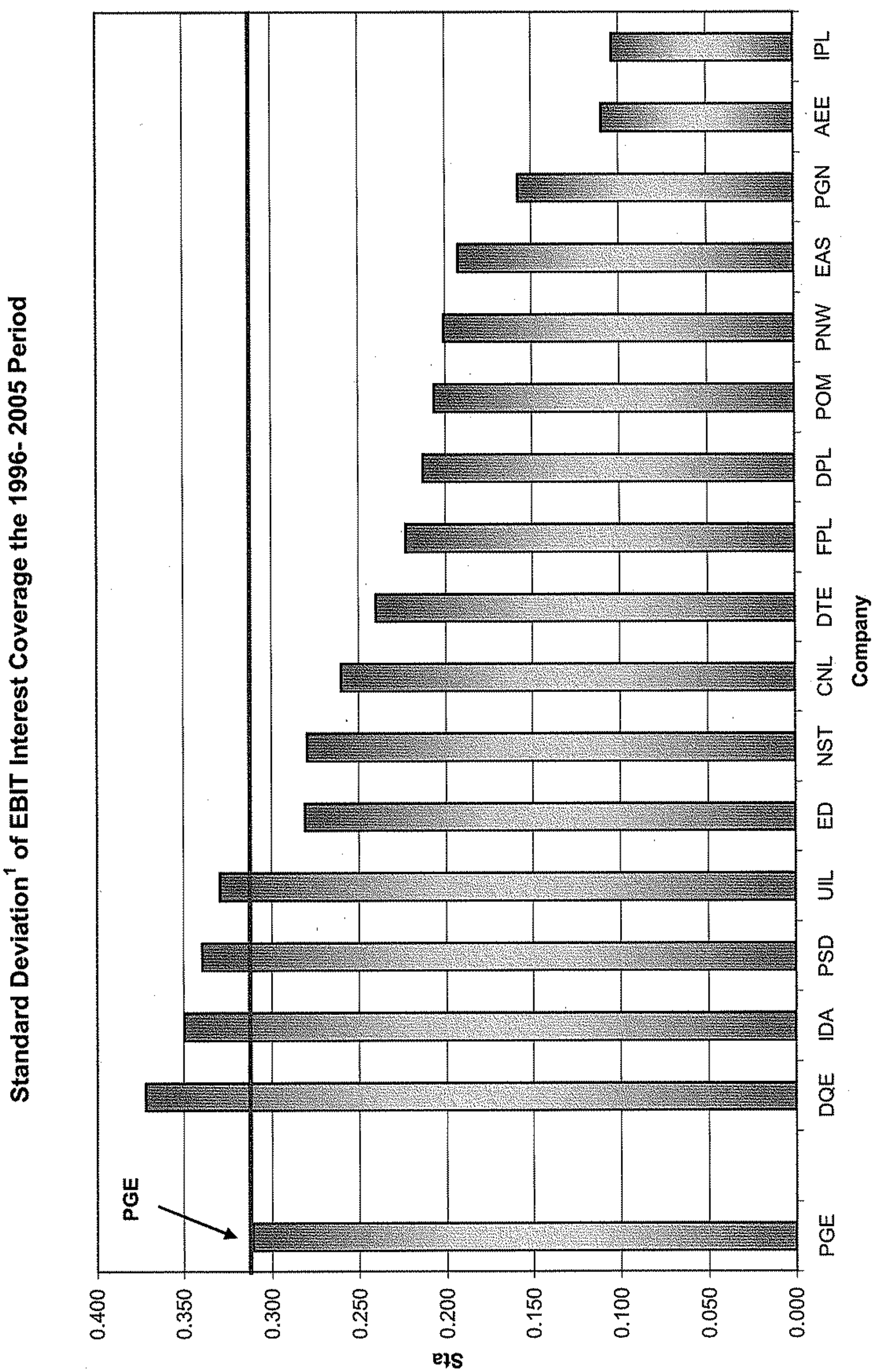
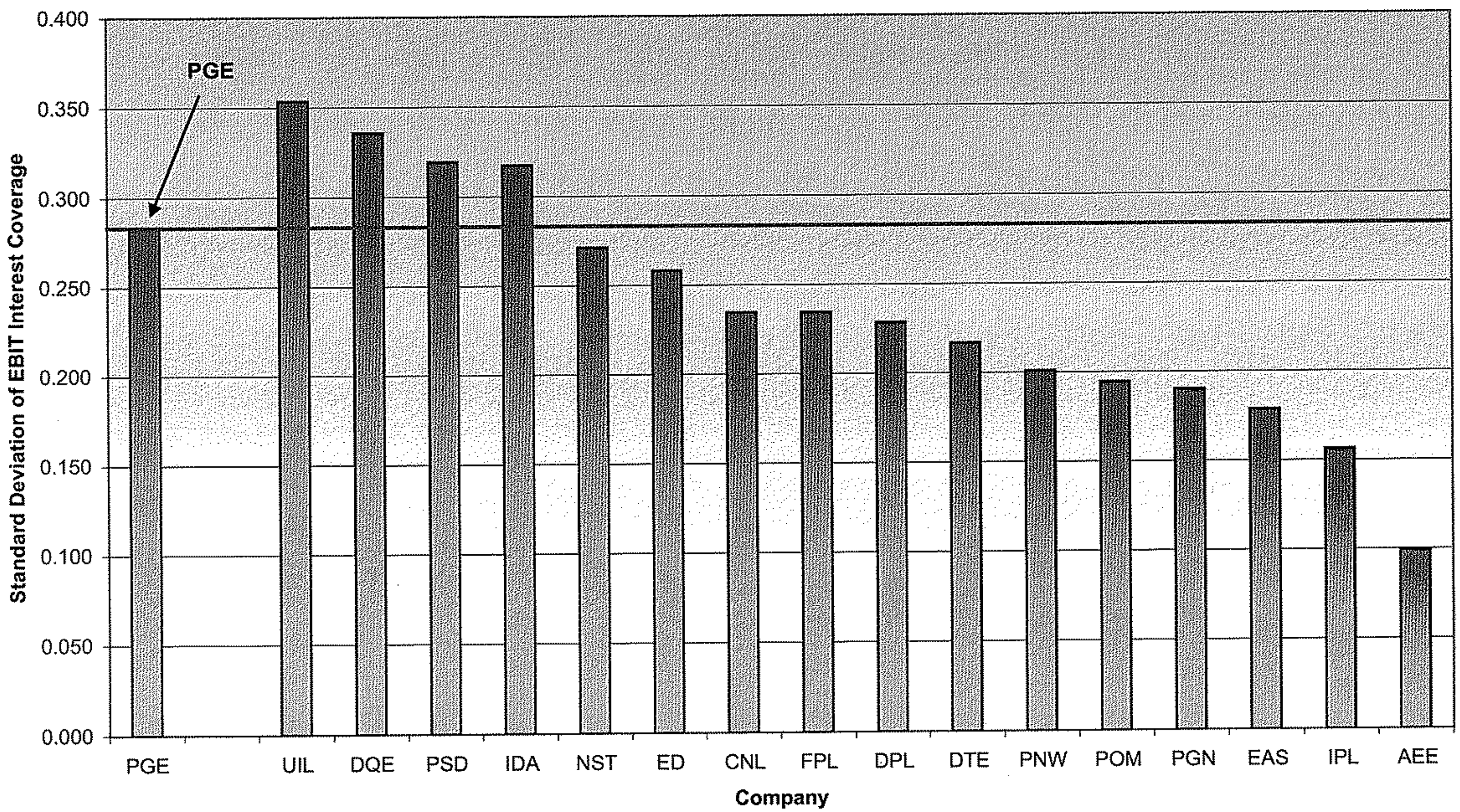


(1) Standard deviation is a measure of volatility.

Prepared by:
Jeff D. Makholm, Senior Vice President
National Economic Research Associates, Inc.

Standard Deviation[1] of EBIT Interest Coverage the 1994- 2005 Period



(1) Standard deviation is a measure of volatility.
(2) Added $110,000,000 back to net income for Potomac Electric Power for 1995 due to non-cash charge.

Prepared by:
Jeff D. Makholm, Senior Vice President
National Economic Research Associates, Inc.

Portland General Electric
PPL Peer Group
Standard Deviation [1] of EBIT Interest Coverage (1994-2005)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Std Dev
Ameren	4.475	4.495	4.410	4.515	4.654	4.517	4.547	4.152	4.083	5.668	3.811	4.408	0.11
Cleco Corporation	3.238	3.286	3.477	3.552	3.460	3.637	3.820	4.165	2.128	3.471	2.839	1.439	0.26
Con Edison	4.419	4.024	4.142	4.065	4.105	5.312	2.879	3.566	2.746	2.344	2.101	3.827	0.28
DPL Inc. [2]	3.611	3.386	3.814	3.990	4.197	4.462	6.461	4.698	3.554	N/A	5.938	5.462	0.21
DQE Inc. [4]	3.211	3.516	3.235	3.041	2.998	3.296	4.958	1.624	2.332	2.588	1.992	1.409	0.37
DTE Energy Co.	3.114	3.350	2.995	3.712	3.610	3.497	3.429	3.086	3.725	2.634	1.295	2.745	0.24
Energy East [4]	2.780	3.032	3.252	3.141	3.565	4.109	3.571	3.039	2.312	2.267	2.506	3.384	0.19
FPL Group	3.923	4.670	5.062	5.408	6.720	6.891	5.041	7.624	5.968	6.488	4.079	3.670	0.22
Idacorp, Inc.	2.440	2.745	3.085	2.974	3.352	2.912	2.118	0.359	3.482	2.288	2.360	3.060	0.35
IPALCO Enterprises	3.929	3.857	4.543	5.558	6.165	6.134	5.760	4.677	5.949	5.080	5.624	5.762	0.10
NSTAR	2.505	2.448	2.961	3.227	4.742	1.778	2.223	3.780	3.103	3.133	3.245	2.201	0.28
Pepco Holdings Inc [3]	3.026	2.956	2.694	2.675	2.742	2.626	2.126	2.627	1.462	2.240	2.542	3.502	0.21
Pinnacle West	2.558	2.862	3.124	3.550	3.525	3.758	4.238	3.454	1.958	2.452	3.648	3.171	0.20
Progress Energy	2.648	2.978	3.082	3.165	3.883	4.050	3.259	4.054	4.304	5.107	4.069	4.274	0.16
Puget Energy, Inc.	2.863	3.155	3.695	1.916	2.607	2.525	2.708	1.717	1.014	1.734	1.684	2.545	0.34
UIL Holdings	1.887	1.941	2.041	1.860	2.218	3.556	2.563	3.340	2.455	3.281	4.900	4.297	0.33
PGE	2.881	3.356	4.206	4.337	3.602	3.828	3.840	1.609	1.923	2.197	2.946	2.898	0.31

Sources: FERC Form 1's from 1994 to 2003 and *Moody's Public Utility Manual*, Moody's Investors Service Vol. 2, 1996.

Notes:
[1] Standard deviation is a measure of volatility.
[2] 2003 FERC Form 1 has not yet been released; SEC Form 10-K is available for 2003, but financial statements include non-utility investments.
[3] Added $110,000,000 back to net income for Potomac Electric Power for 1995 due to non-cash charge.
[4] Used 10-K for DQE and NYSE&G for 1998 because FERC Form 1 data is not readily available.

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	3-year	4-year	5-year	6-year	7-year	8-year	9-year	10-year	11-year	12-year
Ameren	0.20	0.18	0.16	0.15	0.13	0.12	0.12	0.11	0.10	0.10
Cleco Corporation	0.40	0.36	0.38	0.35	0.32	0.30	0.28	0.26	0.25	0.23
Con Edison	0.34	0.28	0.26	0.23	0.34	0.32	0.30	0.28	0.27	0.26
DPL Inc. [2]	0.06	0.25	0.21	0.22	0.21	0.21	0.21	0.21	0.23	0.23
DQE Inc. [4]	0.30	0.24	0.24	0.52	0.47	0.43	0.40	0.37	0.35	0.34
DTE Energy Co.	0.36	0.38	0.33	0.30	0.28	0.27	0.25	0.24	0.23	0.22
Energy East [4]	0.22	0.20	0.18	0.20	0.23	0.22	0.20	0.19	0.18	0.18
FPL Group	0.32	0.27	0.30	0.27	0.26	0.24	0.23	0.22	0.22	0.23
Idacorp, Inc.	0.17	0.21	0.52	0.47	0.43	0.40	0.37	0.35	0.33	0.32
IPALCO Enterprises	0.07	0.07	0.10	0.09	0.09	0.09	0.09	0.10	0.14	0.16
NSTAR	0.20	0.17	0.18	0.21	0.26	0.32	0.30	0.28	0.28	0.27
Pepco Holdings Inc [3]	0.24	0.35	0.30	0.28	0.25	0.23	0.22	0.21	0.20	0.19
Pinnacle West	0.19	0.27	0.24	0.26	0.24	0.23	0.21	0.20	0.20	0.20
Progress Energy	0.12	0.10	0.10	0.14	0.13	0.12	0.14	0.16	0.17	0.19
Puget Energy, Inc.	0.24	0.36	0.31	0.33	0.31	0.30	0.28	0.34	0.33	0.32
UIL Holdings	0.20	0.29	0.26	0.28	0.25	0.28	0.32	0.33	0.34	0.35
PGE	0.16	0.20	0.26	0.32	0.32	0.31	0.32	0.31	0.29	0.28

Sources: FERC Form 1's frc

Notes:
[1] Standard deviation is ε
[2] 2003 FERC Form 1 hε
[3] Added $110,000,000 t
[4] Used 10-K for DQE an

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Exhibit___ (JDM-3)

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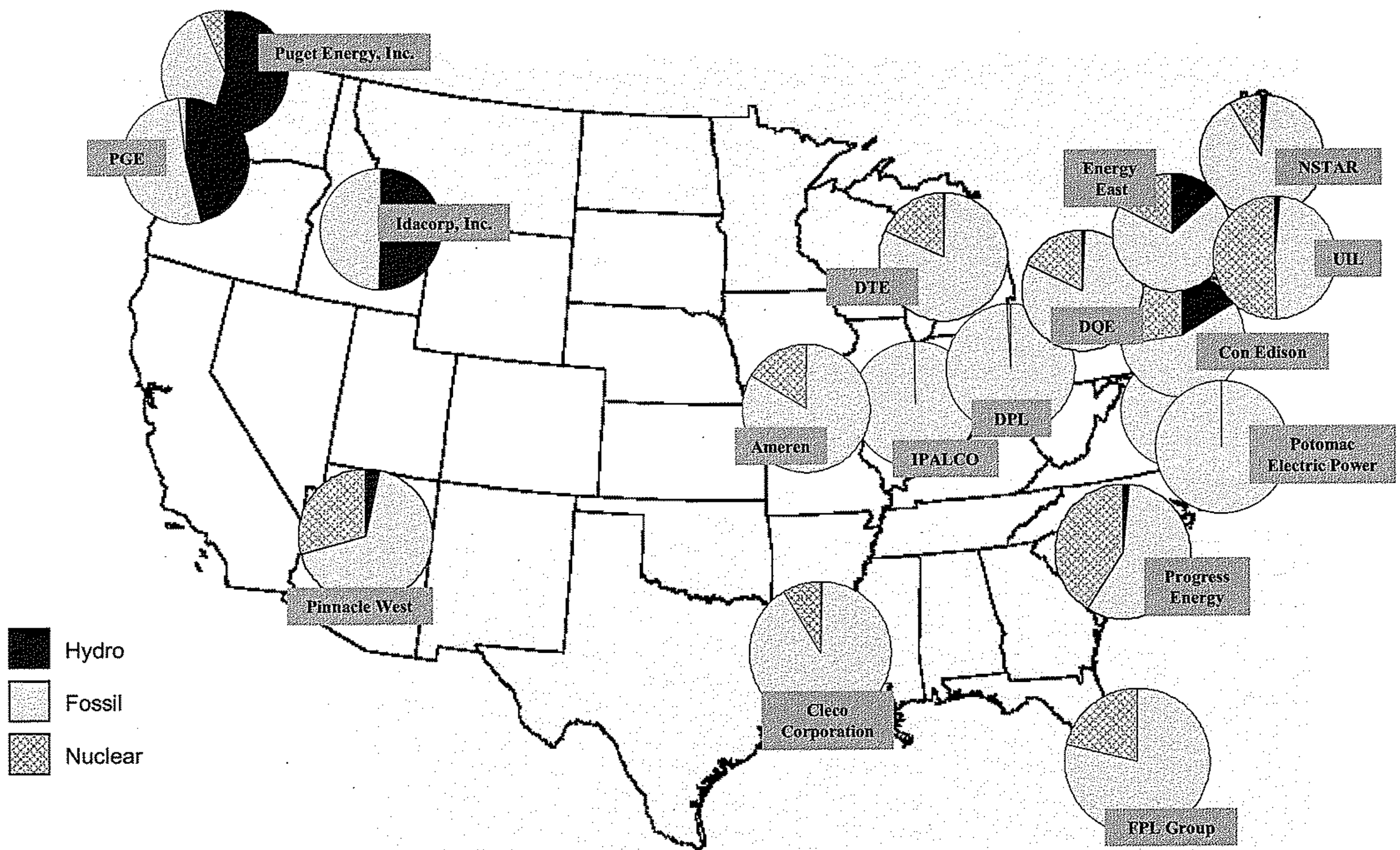
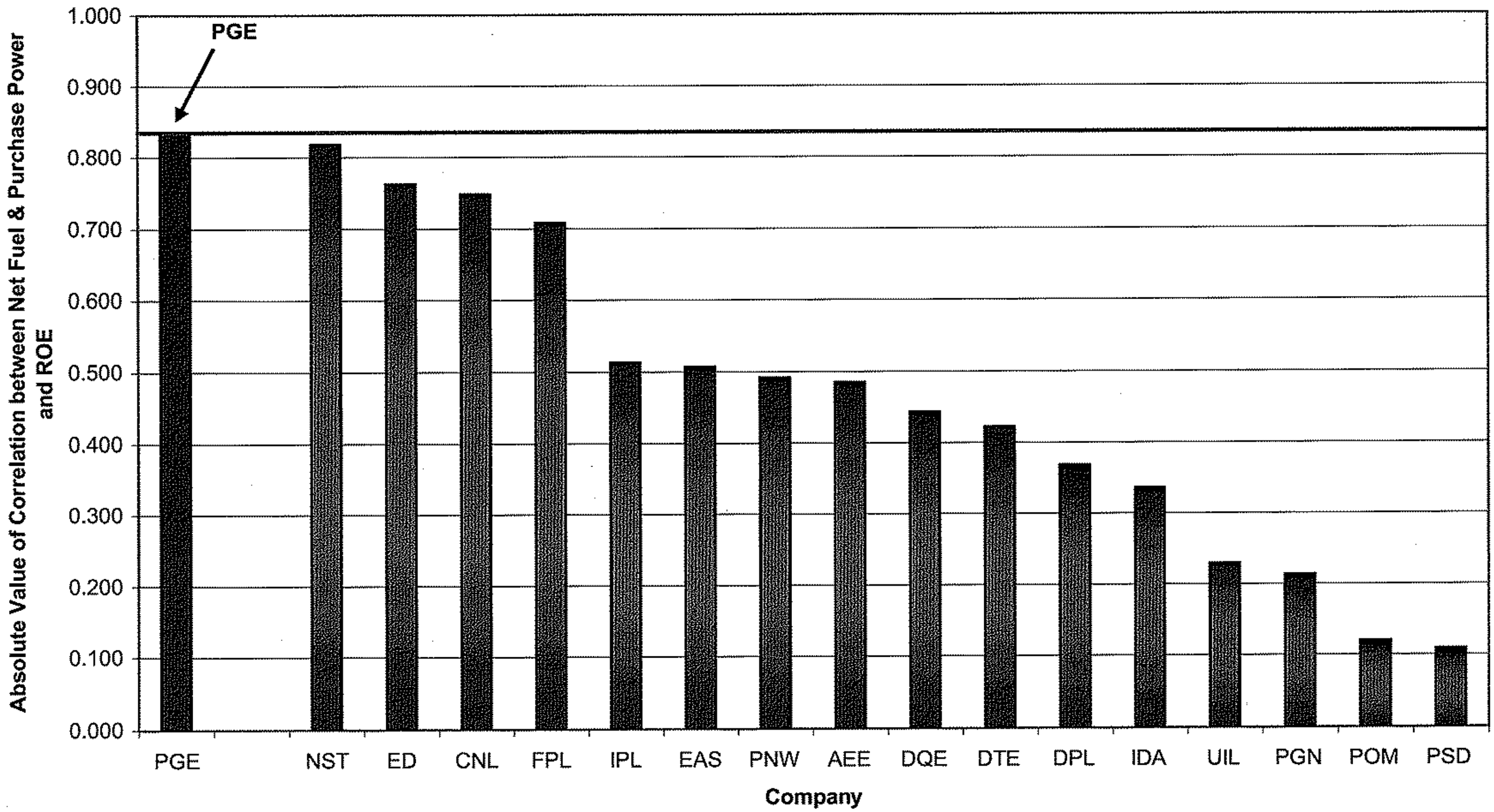
Power Generation 2005
PPL Comparable Group



Sources: PGE Bill Insert (August 2004), 2005 FERC Form 1s, EIA data 2004.
Notes: [1] PGE data from PGE August 2004 Bill Insert.
[2] EIA generation by state data for 2004 was used to identify the fuel sources for the PPL Peer Group's purchased power.

Absolute Value of the Correlation between Net Fuel & Purchase Power 1 and ROE 2 from 1996 to 2005



(1) Net Fuel & Purchase Power = Fuel Costs + Purchase Power Costs - Sales for Resales
(2) ROE = Net Income/ Equity Capitalization.
(3) Ferc Form 1 data to calculate Net Purchase Power is not readily available for DQE and NYSE&G.

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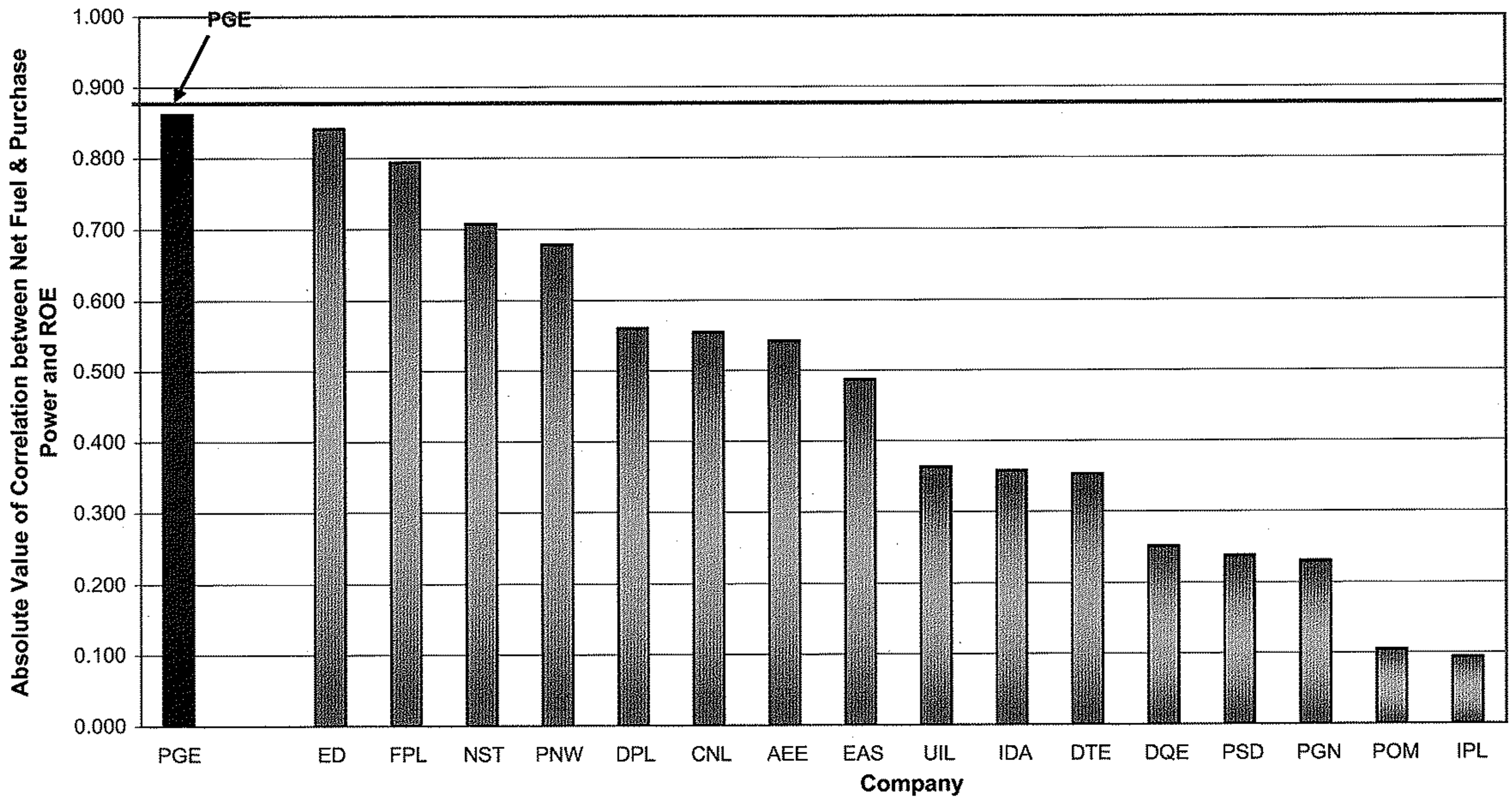
Absolute Value of the Correlation between Net Fuel & Purchase Power [1] and ROE [2] from 1994 to 2005



(1) Net Fuel & Purchase Power = Fuel Costs + Purchase Power Costs - Sales for Resales
(2) ROE = Net Income/ Equity Capitalization.
(3) Correlation for DPL Inc. is from 1994 to 2002 because FERC Form 1 for 2003 has not yet been released.
(4) Added $110,000,000 back to net income for Potomac Electric Power for 1995 due to non-cash charge. for a non-utility venture.

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Portland General Electric
PPL Peer Group
Correlation between ROE[1] and Fuel & Net Purchase Power[2]

		Correlation Between Net Fuel & Purchase Power Costs and ROE	Absolute Value of Correlation (12-Year)	Absolute Value of Correlation (10-Year)
1	PGE	(0.86)	0.86	0.84
2	NSTAR	(0.71)	0.71	0.82
3	Con Edison	(0.84)	0.84	0.76
4	Cleco Corporation	(0.55)	0.55	0.75
5	FPL Group	(0.79)	0.79	0.71
6	IPALCO Enterprises	0.09	0.09	0.51
7	Energy East (5)	(0.49)	0.49	0.51
8	Pinnacle West	(0.68)	0.68	0.49
9	Ameren	(0.54)	0.54	0.49
10	DQE Inc. (5)	(0.25)	0.25	0.44
11	DTE Energy Co.	0.35	0.35	0.42
12	DPL Inc. (3)	(0.56)	0.56	0.37
13	Idacorp, Inc.	(0.36)	0.36	0.34
14	UIL Holdings	0.36	0.36	0.23
15	Progress Energy	0.23	0.23	0.21
16	Pepco Holdings Inc (4)	0.11	0.11	0.12
17	Puget Energy, Inc.	(0.24)	0.24	0.11

[1] ROE = Net Income/ Equity Capitalization.

[2] Fuel & Net Purchase Power = Fuel Costs + Purchase Power Costs - Sales for Resale
[3] 2003 FERC Form 1 has not yet been released; SEC Form 10-K is available for 2003, but financial statements include non-utility investments.
[4] Added $110,000,000 back to net income for Potomac Electric Power for 1995 due to non-cash charge.

Source: Moody's Public Utility Manual, Moody's Investors Service Vol. 2, 1996.

[5] Used 10-K for DQE and NYSE&G for 1998 because FERC Form 1 is not readily available.

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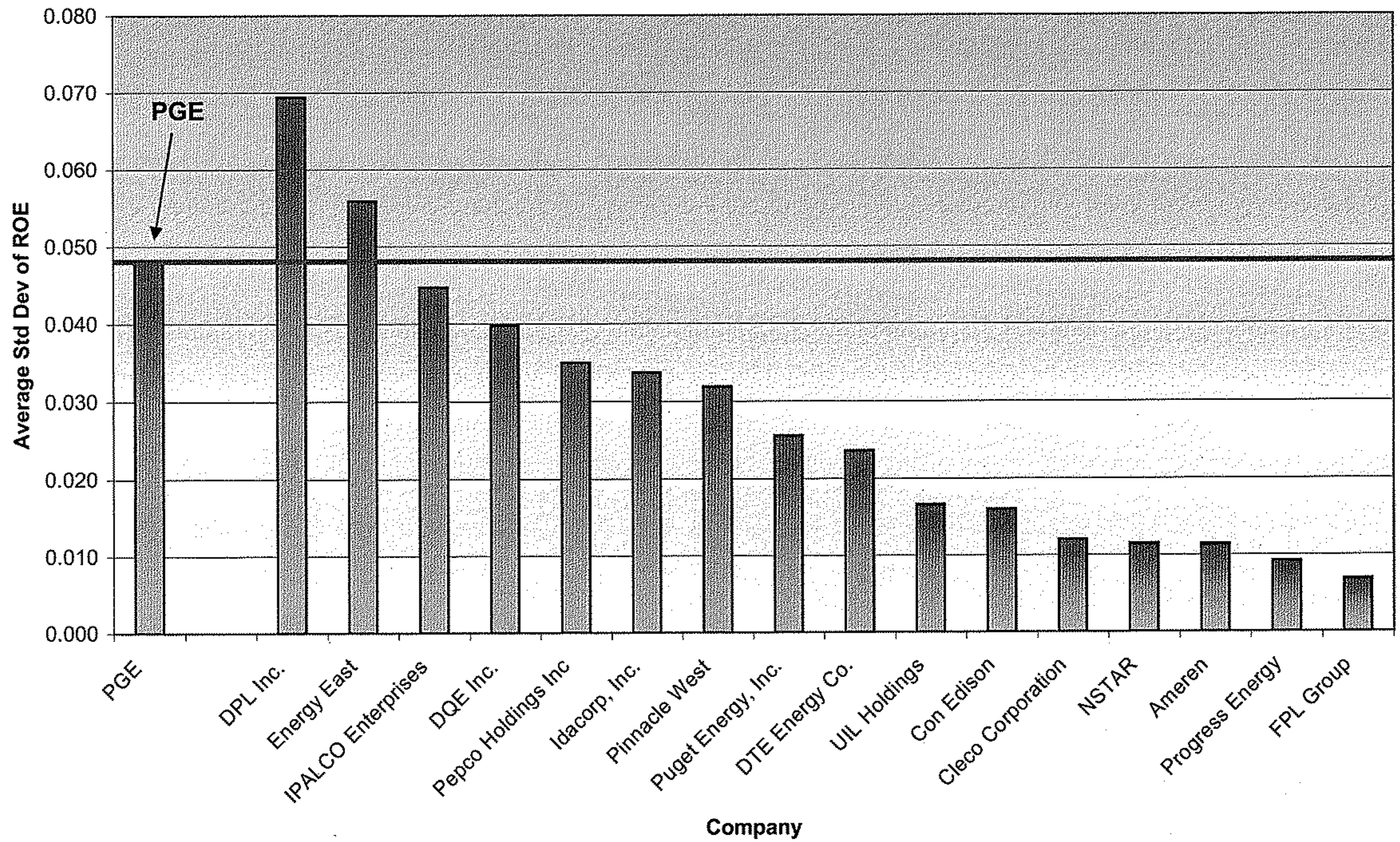
Standard Deviation of ROE for the 1996-2005 Period



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Portland General Electric
PPL Peer Group
Standard Deviation[1] of ROE[2] (1994-2005)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	1996-2005 Std Dev
Ameren	0.138	0.133	0.131	0.119	0.133	0.127	0.141	0.121	0.118	0.142	0.118	0.106	0.01
Cleco Corporation	0.124	0.129	0.133	0.129	0.127	0.140	0.147	0.143	0.140	0.127	0.115	0.110	0.01
Con Edison	0.136	0.130	0.122	0.118	0.126	0.130	0.109	0.120	0.108	0.096	0.078	0.098	0.02
DPL Inc.	0.129	0.131	0.133	0.132	0.133	0.146	0.290	0.215	0.242	0.170	0.293	0.285	0.07
DQE Inc.	0.130	0.133	0.151	0.145	0.076	0.186	0.168	0.099	0.140	0.129	0.204	0.106	0.04
DTE Energy Co.	0.125	0.124	0.097	0.120	0.117	0.118	0.109	0.093	0.139	0.086	0.054	0.093	0.02
Energy East	0.081	0.101	0.111	0.092	0.270	0.182	0.168	0.133	0.095	0.089	0.114	0.122	0.06
FPL Group	0.135	0.136	0.132	0.130	0.131	0.123	0.123	0.127	0.136	0.126	0.122	0.111	0.01
Idacorp, Inc.	0.111	0.127	0.130	0.131	0.138	0.137	0.181	0.103	0.115	0.074	0.079	0.080	0.03
IPALCO Enterprises	0.143	0.142	0.157	0.182	0.195	0.188	0.116	0.134	0.240	0.217	0.247	0.233	0.04
NSTAR	0.133	0.111	0.134	0.128	0.143	0.124	0.121	0.111	0.112	0.117	0.110	0.107	0.01
Pepco Holdings Inc[4]	0.125	0.086	0.118	0.104	0.108	0.044	0.179	0.137	0.099	0.095	0.105	0.136	0.03
Pinnacle West	0.150	0.143	0.137	0.133	0.126	0.063	0.142	0.121	0.087	0.079	0.086	0.058	0.03
Progress Energy	0.115	0.131	0.134	0.110	0.129	0.116	0.134	0.125	0.136	0.136	0.136	0.122	0.01
Puget Energy, Inc.	0.102	0.115	0.115	0.090	0.126	0.135	0.135	0.083	0.078	0.079	0.077	0.073	0.03
UIL Holdings	0.110	0.116	0.090	0.106	0.096	0.115	0.136	0.135	0.135	0.104	0.122	0.116	0.02
PGE	0.126	0.106	0.168	0.139	0.138	0.123	0.128	0.031	0.059	0.048	0.072	0.053	0.05

Sources: FERC Form 1's from 1994 to 2003 and *Moody's Public Utility Manual*, Moody's Investors Service Vol. 2, 1996.

Notes:
[1] Standard Deviation is a measure of volatility.
[2] ROE = Net Income/ Equity Capitalization.
[3] 2003 FERC Form 1 has not yet been released. 2003 SEC Form 10-K is available, but financial statements include non-utility investments.
[4] Added $110,000,000 back to net income for Potomac Electric Power for 1995 due to non-cash charge for non-utility subsidiary.

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Gorman

	Company Name	Common Equity 2009-2011
AEE	Ameren Corporation	53.00%
DTE	Detroit Edison Co.	43.00%
EAS	Energy East Corp.	45.00%
EDE	Empire District Electric Co.	48.50%
FE	FirstEnergy	55.50%
IDA	IDACORP	50.50%
NI	NISOURCE, Inc.	52.00%
OGE	Oklahoma Gas & Electric Co.	54.00%
PNW	Pinnacle West Capital Corp.	53.00%
POM	Potomac Electric Power Co.	48.50%
PSD	Puget Sound Energy	48.00%
XEL	XCEL Energy Inc.	52.00%
	Average	**50.25%**

Stocks, Bonds, Bills, and Inflation

SBBI

2005 Yearbook
Market Results for 1926-2004

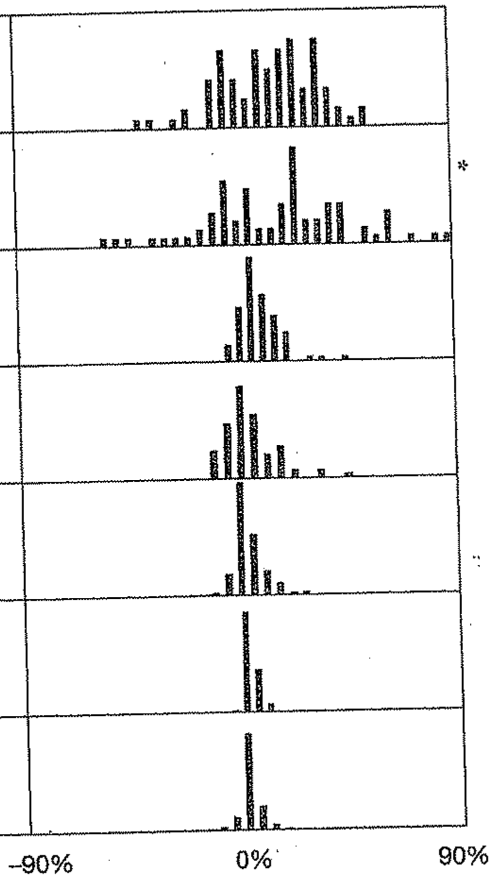
IbbotsonAssociates

Table 2-1

Basic Series: Summary Statistics of Annual Total Returns

from 1926 to 2004

Series	Geometric Mean	Arithmetic Mean	Standard Deviation	Distribution
Large Company Stocks	10.4%	12.4%	20.3%	
Small Company Stocks	12.7	17.5	33.1	*
Long-Term Corporate Bonds	5.9	6.2	8.6	
Long-Term Government	5.4	5.8	9.3	
Intermediate-Term Government	5.4	5.5	5.7	
U.S. Treasury Bills	3.7	3.8	3.1	
Inflation	3.0	3.1	4.3	



*The 1933 Small Company Stocks Total Return was 142.9 percent.

Return to Regular Format

Research:

Portland General Electric Co.

Publication date: 28-Jan-2003
Credit Analyst: Swami Venkataraman, San Francisco (1) 415-371-5071

Corporate Credit Rating

BBB+/Developing/A-2

Business profile: Strong

Financial policy: Moderate

Bank lines/Liquid assets:
Portland General Electric (PGE) has two bank lines—a multi-year, $150 million facility maturing in July 2003 and a $72 million, 364-day facility maturing in June 2003 used mainly for LOCs. Both facilities are secured by first mortgage bonds issued by PGE.

Outstanding Rating(s)	
Portland General Electric Co.	
Sr unsecd debt	
Local currency	BBB
Sr secd debt	
Local currency	BBB+
CP	
Local currency	A-2
Sub debt	
Local currency	BBB
Pfd stk	
Local currency	BBB-
Enron Corp.	
Corporate Credit Rating	D/Nm/NR
Sr unsecd debt	D
Sub debt	
Local currency	D
Pfd stk	
Local currency	D
Transwestern Pipeline Co.	
Corporate Credit Rating	BB/Watch Pos/--

Corporate Credit Rating History	
Mar. 18, 1996	A/A-1
Dec. 7, 2001	BBB+/A-2

Company Contact

Major Rating Factors

Strengths:

- A supportive regulatory environment in Oregon;
- Efficient, low-cost generation resources;

- A strong financial profile, supported by the 48% equity layer mandated by the OPUC; and
- A growing and increasingly diversified economic base in the Portland region.

Weaknesses:

- A significant dependence upon wholesale power markets to meet native load requirements,
- The impact of the economic slowdown in the manufacturing- and technology-heavy economy of PGE's service territory,
- Significant exposure to "hydro-risk" in its owned generation as well as purchased power contracts, and
- Regulatory uncertainty over the FERC investigation of its dealings with parent, Enron Corp., in the energy trading business.

Rationale

The 'BBB+' corporate credit rating (CCR) on Portland General Electric Co's. (PGE) reflects both the establishment of specific structural features that satisfy Standard & Poor's Ratings Services ring-fencing criteria along and evidence that including PGE in Enron's bankruptcy would have severe economic consequences for each. PGE is now rated primarily on its stand-alone credit quality. PGE's rating is higher than that of its parent because of the perceived economic disincentives of Enron or its creditors to file PGE into the Enron bankruptcy. In Standard & Poor's view, PGE's value as a going concern is greater than if it were part of a consolidated bankruptcy filing.

PGE's CCR reflects the supportive regulatory environment in Oregon, low-cost generation, and a strong financial profile. PGE's service territory grew rapidly in the 1990s but has since absorbed the brunt of the manufacturing and technology recession. Conservation efforts have added to the decline in sales.

PGE has 1,909 MW of efficient, low-cost generation resources, which comprise a mix of hydro, coal, and gas-fired generation. PGE also benefits from cheap hydropower purchases from the Columbia River power system and Bonneville Power Administration. However, PGE must purchase a large amount (35%) of its energy requirements from the wholesale market, which constitutes the utility's principal business risk. This risk is compounded by the predominance of hydroelectric power in its supply portfolio.

PGE's cash flow coverages were affected by the western U.S. power crisis in 2001 but should improve from 2002 onward given the implementation of rate hikes in October 2001 and the institution of a power cost adjustment (PCA) mechanism to recover costs deferred in 2001. Going forward, the new resource valuation mechanism approved by the Oregon Public Utility Commission (OPUC) allows for the annual reset of rates at the beginning of each year based on the company's forecast of net variable power costs for that year. Standard & Poor's expects that cash flow coverage of interest will exceed 4.5x over the next few years, which is sufficient for the rating.

Liquidity and financial triggers.

Two bank lines--a multi-year, $150 million facility maturing in July 2003 and a $72 million, 364-day facility maturing in June 2003, used mainly for LOCs--form the basis of PGE's liquidity. Both facilities are secured by first mortgage bonds issued by PGE. On Sept. 30, 2002 PGE had $70 million drawn on these revolvers.

PGE has maintained access to the capital markets through the Enron bankruptcy. The company recently financed a total of $250 million of first mortgage bonds in two separate transactions. The proceeds will be used to repay credit line draws and refinance maturities through the first quarter of 2003. PGE expects to remarket $142 million in pollution control bonds that are likely to be 'put' back to PGE in May 2003. Standard & Poor's does not expect this to pose any challenges, particularly since PGE has only $90 million in debt maturing between 2004 and 2006.

Outlook

The developing outlook is reflective of the ongoing auction process of PGE. As a result of this process, PGE's ratings may improve, decline, or remain the same, depending on the credit standing of the ultimate purchaser.

Business Description

PGE is an integrated electric utility serving about 736,000 customers in northwest Oregon, including the cities of Portland and Salem. PGE also buys and sells electric energy in the wholesale markets to meet its load and offload its surplus, primarily within Oregon or at the Oregon border. PGE has a 3,150 square-mile service area with a population of approximately 1.5 million. PGE is a wholly owned subsidiary of Enron Corp. (D/--/--), which is in bankruptcy. Enron recently announced that it would accept bids for 12 of its operating businesses, including PGE, a process that will be supervised by the bankruptcy court.

Rating Methodology

PGE's credit quality reflects its utility operations and financial performance. Standard & Poor's believes that PGE's credit quality is insulated from that of its parent, Enron, following the implementation of the requisite ring-fencing structural mechanisms and economic incentives that appear sufficient for Enron not to file PGE into bankruptcy.

PGE's first mortgage bonds are rated the same as the firm's CCR. Although utility property collateralizes these bonds, Standard & Poor's analysis of ultimate recovery does not project the value of such collateral to exceed substantially the maximum amount of first mortgage bonds that could be outstanding under the terms of the indenture. Therefore, Standard & Poor's does not have the confidence that first mortgage bondholders would receive their principal in a bankruptcy scenario, which would be necessary in order to consider a higher secured rating.

The utility's unsecured debt is rated one notch lower than the CCR because unsecured bondholders are disadvantaged by the presence of first mortgage bonds. The company's preferred stock is rated two notches lower than the CCR based on the subordinated characteristics of preferred stock.

Regulation

The OPUC regulates the company's electric rates. OPUC regulation has historically been very supportive of utility credit quality.

Western power crisis.

PGE was actually long on power during the power crisis, since it had contracted for energy in advance, and demand was lower owing to mild temperatures in winter 2000-2001. This allowed PGE to sell its surplus power at high prices. However, PGE did incur losses once wholesale prices fell, following the FERC's imposition of price caps, which forced PGE, which was long on expensive power purchased in early 2001, to sell its surplus at the lower prices. PGE requested, and the OPUC approved, a PCA mechanism, effective for the nine-month period of January-September 2001, that provided a method for PGE to defer all power costs that exceeded a baseline amount to be recovered over 3.5 years. PGE deferred $89 million under this mechanism.

General rate case and a new rate-setting mechanism.

The OPUC issued an order with regard to PGE's general rate case in August 2001 that included several favorable features:

- An ROE of 10.5%;
- Retail rate increases, effective Oct. 1, 2001, of 31.6%, 37.3%, and 53.2% for residential, commercial, and industrial customers, respectively--this results in about $440 million in additional annual revenues based on the October 2001-December 2002 test period;
- Functional unbundling of costs and rates between generation, transmission, distribution, and customer service--the FERC approved a 12.6% ROE on transmission; and
- Two mechanisms to manage power supply risks through December 2002--the resource valuation mechanism (RVM) and the PCA.

The RVM is an annual estimate (in November) of the cost of power that is incorporated into PGE's rates. The RVM for 2003 was approved at $453 million for 2003, after a $14 million disallowance for high-priced forward contracts entered into in early 2001. This amount is derived from an economic dispatch model of PGE's system and incorporates load estimates, planned generation outages, heat rates, existing power purchase contracts, and other relevant considerations. The model assumes average water levels for hydro production. Thus, the RVM effectively reflects the forecasted cost of power supply for the next year except for unforecasted spot purchases and sales, unexpected major generation outages, and, importantly, lower-than-average rainfall. Based on the changes in the RVM Part B value (short-term resources), PGE is significantly lowering rates in 2003, by approximately 9% to 17% for commercial and industrial customers. Residential customers will receive a more modest rate reduction of approximately 2%.

The PCA through 2002 requires PGE to absorb all variances up to $28 million. Variances exceeding $28 million are shared in bands with customers in progressively higher percentages, starting with 50% up to $38 million and going to 95% beyond $200 million. PGE will not have a PCA for 2003, largely owing to the existence of the RVM mechanism and the fact that PGE is largely self-sufficient for 2003.

In August 2002 PGE filed an integrated resource plan with the OPUC that envisions the company procuring long-term sources of power to meet substantially all of its needs. The need for a PCA in 2004 and beyond will be assessed in the light of an approved resource plan. The OPUC's approval of the resource plan is expected in 2003.

Overall, the prompt institution of a PCA in January 2001, provision for full recovery of costs deferred during the crisis, large rate hikes instituted in October 2001, and the RVM mechanism instituted during the rate case are all indicative of supportive regulation in Oregon. However, it is possible that PGE would be left without a PCA mechanism even in the integrated resource plan, which would expose the company to varying water levels from which it could benefit in an above-average year or take a hit in a low water year. It is likely that the OPUC will allow PGE to defer and recover the costs of a low water year only when such costs are high and exceed, say, $60 million, the amount that the OPUC proposed as a deadband for a possible 2003 PCA and which was rejected by PGE.

Oregon deregulation law.

In 1999, Oregon's governor signed into law State Senate Bill 1149 (SB1149). As later amended for a delay in implementation to March 1, 2002, SB1149 provides all non-residential customers of investor-owned utilities direct access to competing energy service suppliers (ESS). Residential and small business customers have no direct access choices but can purchase electricity from a "portfolio" of rate options provided by PGE that includes a basic service rate, a time-of-use rate, and renewable resource rates. SB1149 also provides for a 10-year public purposes charge, equal to 3% of retail revenues, designed to fund special public purpose programs such as conservation and renewable resources.

PGE is not required to divest generation assets and can recover all stranded costs associated with choices exercised by non-residential customers through a non-bypassable transition charge to that customer. PGE is economically neutral to any choice made by a customer under Oregon's law. Commercial and industrial customers can choose between standard or market-based offerings from PGE or may go to an ESS. Among residential customers, approximately 19,000 have chosen renewable options, while approximately 1,600 have chosen the time-of-use option. There are three PGE-registered ESS, but none are serving PGE's customers thus far.

FERC investigations.

The FERC recently upgraded its inquiry into the energy trading practices of PGE into a formal investigation. In its order, the FERC's staff states that there exists preliminary evidence of different failures in the company. The FERC is investigating:

- Whether Enron and PGE engaged in transactions that violated affiliate rules, with Avista acting as a middleman and
- Whether PGE and Enron knowingly engaged in transactions that may constitute violations of their codes of conduct and the FERC's own standards of conduct;

If the charges are substantiated, various remedies could be applied under the Federal Power Act, including refunds of any profits made from such transactions and revocation of the companies' market-based rate authority. A revocation of market-based rate authority would not have a large negative effect on PGE's finances, since it engages in wholesale transactions mainly to balance its load requirements with its power supply. In the absence of market-based rate authority, PGE can still purchase power as it always has; however, wholesale sales would be priced based on a cost-based tariff like that of the Western Systems Power Pool (WSPP) or other similar agreements. The cost basis for power sold according to the WSPP tariff reflects the incremental cost of the power source (which includes wholesale power purchases) plus a small margin that varies by the type of trade. Thus, even if the utility must purchase power at potentially high market prices, it will either recover its costs through rates or, if some excess power is sold, the WSPP tariff will provide for cost-recovery plus a small margin. PGE would, however, lose its ability to participate in a run-up in wholesale prices when it has excess power to sell.

Ring-Fencing

Standard & Poor's takes the general position that the rating of an otherwise financially healthy, wholly owned subsidiary is constrained by the rating of its weaker parent. Thus, PGE's current ratings are underpinned by various structural or "ring-fencing" mechanisms designed to separate Portland General's credit quality from that of Enron.

Management intent.

Enron management's plans for PGE are a crucial component of the ring-fence. To this extent, Enron management's assurance to Standard & Poor's, in writing, that it has no intention of bringing PGE into bankruptcy, was key to the maintenance of the rating immediately following the termination of the sale agreement with Northwest Natural Gas Co (A/Stable/A-1).

Additionally, Enron recently commenced accepting bids for 12 of its assets, including PGE, indicating management's intent to keep PGE out of the Enron bankruptcy and further bolstering the case to rate PGE on a "stand-alone" basis. The bankruptcy court is supervising the auction under section 363 of the bankruptcy code. However, this alone would not be sufficient to ring-fence PGE, since the outcome of the auction process is anything but certain. Transwestern Gas Pipeline Co., another 100% subsidiary of Enron involved in the auction process, is rated 'BB'/Watch Positive. These ratings are not based on the stand-alone credit quality of Transwestern because Transwestern could still remain a part of a reorganized holding company that emerges from bankruptcy. Thus, in order for PGE to be rated on a "stand-alone" basis, further structural mechanisms are necessary.

Structural mechanisms.

Certain structural features of the ring-fencing of PGE also support the separation of PGE's ratings from those of its parent. In addition to a "non-consolidation" opinion to the effect that PGE would not be substantively consolidated into Enron's bankruptcy estate, PGE has issued one share of a special class of junior preferred stock (the golden share). The vote of the golden share is required for PGE to file a voluntary action in bankruptcy, with certain exceptions.

The share will be issued/transferred only to an entity that is "independent" of PGE and its affiliates during the period of ownership and for five prior years. The share was issued to an independent party on Sept. 30, 2002. The issue of the junior preferred stock with the above rights is crucial to mitigating bankruptcy risk. The requirement that the holder of the golden share have due regard for creditors is key in ensuring that PGE cannot be filed into bankruptcy for the benefit of Enron's creditors and in a manner detrimental to PGE's bondholders. The holder of the share meets the independence tests as required under Standard & Poor's ring-fencing criteria.

Regulatory insulation.

Further supporting the ratings separation is the fact that Standard & Poor's views the OPUC as being among the most supportive of utility credit quality in the country. Indicative of this support are the several restrictive conditions imposed upon Enron when acquiring PGE in 1997 that served to largely insulate PGE from Enron's subsequent woes. Some of the important restrictions include the requirement to maintain a 48% equity level at PGE, notification requirements for special or large dividends to Enron, and maintenance of separate debt and preferred stock credit ratings. In addition, PGE is required to maintain its own accounting system, separate from Enron's.

The effectiveness of OPUC's rules can be gauged from the fact that Transwestern pipeline and Northern Natural Gas, the FERC regulated gas pipelines that are both subsidiaries of Enron, pledged their assets as collateral for loans in November 2001 and then passed the funds to Enron through promissory notes just weeks before Enron's collapse. Transwestern's $550 million of loans to Enron has been written off by the pipeline, and Northern Natural is still liable for $450 million. Whatever the merits of these transactions, Enron was unable to similarly borrow money from PGE, illustrating the effectiveness of regulatory insulation.

Economic disincentives.

Typically, Standard & Poor's will not rate even ring-fenced subsidiaries much higher than the rating of the consolidated entity. With the rating differential being constrained to one full rating category (three "notches") above the credit quality of the consolidated entity. In PGE's case, of course, the differential is much wider.

Besides the ongoing auction process to sell PGE, PGE's rating is higher than that of its parent because of the perceived economic disincentives of Enron or its creditors to file PGE into bankruptcy. In Standard & Poor's view, PGE's value as a going concern is greater than if it were part of a consolidated bankruptcy filing. Standard & Poor's has concluded that if an otherwise healthy PGE were filed into bankruptcy, the adverse financial and contractual consequences of such a filing would outweigh any advantages. A bankruptcy filing by PGE would likely result in defaults under PGE's portfolio of power purchase and sale agreements. Standard & Poor's has been advised that the nature of these agreements is such that a default would trigger termination payments by the company for net out-of-the-money positions. A downgrade of ratings below investment grade could require the company to post additional collateral (see below). Standard & Poor's further understands that these contracts constitute "safe-harbored" contracts for purposes of Sections 556 and 560 of the Bankruptcy Code and that the defaults would not be affected by the "automatic stay" provision of the federal bankruptcy code. Standard & Poor's believes that the financial penalty that would be suffered by PGE in the event of a downgrade to non-investment grade status, or, a priori, a PGE bankruptcy is a material disincentive for Enron's creditors.

As of Nov. 1, 2002, if PGE were to be downgraded below investment grade by Standard & Poor's, additional collateral that could be requested by counter-parties upon such a downgrade was approximately $117 million. In addition, under a downgrade scenario, the company could be asked by counter-parties for up-front cash payments for PGE's purchase of gas and power. These purchase requirements arise because PGE is short on generation capacity and must purchase a significant portion of its power needs from the wholesale market. In 2001, the utility relied on the wholesale markets for 35% of the energy requirements for its retail customer requirements.

Markets

A solid service territory enhances PGE's business profile of "4". The service territory covers northwest Oregon, including Portland and Salem.

Strengths include:

- Solid 2.3% and 2.6% customer and sales growth rates, respectively, between 1990 and 2000, well-above the national and WSCC averages--Portland has been able to attract new business based on relatively inexpensive industrial land, a plentiful water supply, and competitive energy costs;
- The growth in Oregon's nonagricultural job base in recent years, which has significantly restructured the state's economic profile, diversifying it away from pulp and paper to include the technology and services industries (including names such as Intel Corp., LSI Logic, Mitsubishi, Boise Cascade Corp., Boeing Co., and Nike Inc.) and international trade with China, India, and Pacific Rim countries. The technology industry is now the largest manufacturing industry in Oregon. Industrial revenues for PGE have grown by a very strong 12% annually over the last five years; and

- A relatively large residential sector, which accounted for 43% of retail revenues in 2001. Although industrial customers account for 20% of retail revenues, customer concentration is not a concern. The top 10 customers account for 14% of retail revenues with the top customer accounts for 2.8%. Also, industrial revenues are more diversified, with paper and pulp contributing about a third of revenues, down from over 50% 10 years ago.

Challenges include:

- The recession, which hit Oregon the early and hard--the fast growth of the last few years has meant that the Portland region has been severely affected by the economic slowdown. Its unemployment level ranked as the highest among the 50 states thru June 2002. Oregon's dependence on manufacturing (26.3% durable goods share of the gross state product versus 10.9% for the U.S.), specifically high-tech manufacturing, intensified the effects of the slowdown;
- Conservation measures implemented during the western U.S. power crisis, which will also dampen growth going forward; and
- The region's international trade industry, which is susceptible to weakness in the Asian economy.

Operations

Owned generation resources are efficient.

PGE has an efficient low-cost fleet of hydro, coal and gas-fired generation resources, either owned or through long-term contracts for a portion of a plant's output. In 2001, PGE owned 2,046 MW of capacity, which consisted of natural gas/oil (38%), coal (32%), and hydro (30%). PGE has long-term, hydro-power, take-or-pay contracts for 681 MW with Mid-Columbia Public Utility Districts (PUDs) and 258 MW with Bonneville Power Administration (possibly increasing to 560 MW in 2006). PGE's hydroelectric generation sources, both owned and purchased, are low cost. The PUDs that supply power to PGE have among the lowest rates in the nation. PGE's coal plants are also efficient and have a low cost of generation. Debt burden is relatively modest at $545 per kilowatt (kW) of owned capacity (including transmission and distribution debt) and $355/kW of peak load.

Short capacity position creates operational risk.

PGE is short on capacity, a factor that contributes significantly to its operating risk profile. PGE purchased nearly 35% of its energy requirements for its retail load in 2001. If wholesale sales are included, purchased power accounts for a huge proportion (64%) of power sources. Moreover, 1,300 MWs of owned and long-term purchased-power contracts are for hydro resources, which are exposed to the sometimes-significant variations in rainfall. Thus, risk management policies are tremendously important.

Wholesale sales and risk management.

Aside from its retail load, PGE has legacy power sales contracts with some entities--the cities of Glendale and Burbank, Southern California Edison (SoCal Ed), Snohomish PUD, Canby Utility Board, and Eugene Water & Electric Board. Also, given the fact that PGE purchases nearly 35% of its requirements for its native load, the company also must engage in some trading activity to manage its cost of power supply. Thus, sales of wholesale power constitute a large portion (42%) of total electric sales.

These contracts were entered into in the late 1980s, when PGE had surplus capacity. The shutdown of the Trojan nuclear facility (about 1,000 MWs) and growing loads made PGE short on capacity. The Snohomish and Canby contracts expired in 2001 while the SoCal Ed contract expires in December 2002. These are fairly small contracts, for capacity ranging between 10 MW and 50 MW.

PGE manages risk on its regulated portfolio by utilizing a maximum 95% VAR limit and managing its open positions on a daily, monthly, and rolling 24-month basis. PGE also maintains a VAR limit on its non-regulated portfolio as well as limits on its open position.

PGE owns 79% of the Kelso-Beaver Pipeline, which connects its Beaver station to the Northwest Pipeline, an interstate gas pipeline operating between British Columbia and New Mexico. Firm gas supplies for Beaver, based on anticipated operation of the plant, are purchased at fixed prices for up to 24 months in advance. PGE has access to 76,000 decatherms per day of firm transportation capacity, sufficient to operate Beaver at a 70% load factor.

PGE's estimated cost to decommission the Trojan nuclear plan was $337 million in 2001; the cost has been falling slightly in the past few years due to lower inflation. PGE collects $14 million annually from customers through 2011 for decommissioning costs (and records an equal amount in amortization expense), sufficient to fully fund its decommissioning requirements.

Competitive Position

PGE's rates are currently above state averages, owing primarily to the large increases instituted in October 2001. Starting Jan. 1, 2003 PGE reduced rates between 9% and 17% for commercial and industrial customers and approximately 2% for residential customers, reflecting lower prices in the wholesale markets. This should bring PGE's rates closer to the state average. Further, retail competition has not had much success in Oregon, and no customer has yet migrated to an ESS since deregulation's implementation in March, although customers have chosen other options from PGE besides the standard cost-of-service offer.

Strengths include:

- PGE's low production costs at its coal and hydro stations and efficient utility operations, which aid in its competitiveness;
- The minor nature of the competitive threats to the company's regulated electric transmission and distribution business; and
- The relatively small (only about 20%) amount of retail revenues that are generated by the industrial sector.

Challenges include:

- The utility's proximity to California's volatile energy environment.

Financial Policy Moderate

Financial Profile

PGE's financial policy is moderate, reflecting management's conservative financial policies as well as the regulatory mandate to maintain a 48% common equity level. However, financial policy may undergo a change once PGE is sold under the auction process currently underway.

Highlights include:

- OPUC's requirement that PGE maintain a 48% common equity level;
- PGE's adjusted total debt-to-total capital ratio, which is expected to be under 50%; and
- The utility's capital expenditures, projected at about $160 million annually, which are expected to be funded fully from internal cash flows.

Profitability and cash flow.

- PGE's cash flow should remain solid due to stable operations, modest growth, supportive regulation, and cost containment.
- The absence of unregulated businesses will provide stability to earnings and cash flows.
- The RVM should provide for rates that are closely linked to actual cost of power supply.
- Adjusted funds from operations to interest coverage and adjusted funds from operations to average debt are expected to be over 4.5x and 25%, respectively, and are adequate for the current ratings.

Capital structure and financial flexibility.

Utility construction expenditures between $150 million to $200 million are expected to be fully internally funded. PGE will likely look to procure additional generation resources in order to reduce its 24% short position, either by constructing new generation or entering into long-term power purchase contracts. However, PGE's capital structure should remain relatively stable at about 50% over the next several years. A regulatory requirement that the utility maintain a 48% common equity layer further supports this level.

Financial Statistics--Portland General Electric Co.					
	--Year ended Dec. 31--				
	2001	2000	1999	1998	1997
Income statement (mil $)					
Gross revenues	3,047	2,253	1,378	1,176	1,416
Operating expenses (excl DD&A)	2,705	1,789	949	746	970
Depreciation and amortization	170	164	155	149	155
Pretax operating income	94	300	274	281	291
Gross interest expense	72	72	69	75	74
AFUDC and deferrals	3	0	0	0	0
Pretax income	25	238	206	219	196
Income taxes	2	97	78	82	70
Net income from continuing operations	23	141	128	137	126
Earnings protection					
EBIT interest coverage (x)	1.3	4.3	4.0	3.9	3.6
Adjusted EBIT interest coverage (x)	2.1	3.5	3.2	3.2	2.9
Preferred dividend coverage (x)	2.1	3.6	3.3	3.2	3.1
EBITDA interest coverage (x)	3.5	6.6	6.2	5.9	5.7
Return on common equity (nominal) (%)	1.4	12.8	12.2	14	13.3
Common dividend payout (%)	190.5	59.1	65.3	36.8	51.6
Annual O&M growth (%)	(42.6)	5.2	0.8	3.8	(3.9)
Annual expense growth (excl. DD&A) (%)	51.2	88.5	27.2	(23.1)	57
O&M/revenues (%)	5.0	11.7	18.1	21.1	16.9
Total operating expenses (excl. DD&A)/revenues (%)	88.8	79.4	68.9	63.4	68.5
Balance sheet (mil $)					
Cash and temporary investments	8	60	0	4	3
Gross plant	3,529	3,423	3,295	3,182	3,078
Net plant	1,886	1,891	1,865	1,819	1,818
Total assets	3,474	3,452	3,167	3,162	3,256
Short-term debt	347	68	298	0	0
Long-term debt	769	798	701	846	903
Preferred stock	29	30	30	105	105
Common equity	1,090	1,099	1,041	996	910
Total capitalization	2,235	1,995	2,070	1,947	1,918
Total off-balance-sheet obligations	66.5	85.7	103.8	119.3	132.3
Balance-sheet ratios (%)					
Short-term debt/total capital	15.5	3.4	14.4	0.0	0.0
Long-term debt as a % of capital	34.4	40	33.9	43.5	47.1
Preferred stock/total capital	1.3	1.5	1.4	5.4	5.5
Common equity/total capital	48.8	55.1	50.3	51.2	47.4

Adjusted total debt/total capital	54.7	45.7	50.7	46.7	50.5
Cash flow (mil $)					
Net income	23	141	128	137	126
Depreciation and amortization	170	164	155	149	155
Deferred taxes and ITC	(31)	(8)	(3)	(5)	(58)
AFUDC and deferrals	3	0	0	0	0
Other funds from operations (FFO) adjustments	63	42	(16)	43	59
FFO	222	339	264	324	282
Preferred dividends	(2)	(2)	(2)	(2)	(2)
Common dividends	(40)	(81)	(81)	(49)	(63)
Net cash flow (NCF)	264	422	347	275	217
Working capital changes	(298)	85	(28)	(59)	77
Capital expenditures (capex)	(197)	(173)	(188)	(144)	(180)
Discretionary cash flow	(321)	168	(35)	70	114
Cash flow adequacy					
FFO interest coverage (x)	3.8	5.6	4.7	5.2	4.8
Adjusted FFO interest coverage (x)	3.2	4.6	3.8	4.2	3.8
FFO/average total debt (%)	22.4	36.4	28.6	37	29.4
Adjusted FFO/average total debt (%)	18.3	29.6	22.4	28.1	26.5
NCF/capex (%)	91.4	148.0	96.3	189.6	120.6
AFUDC--Allowance for funds used during construction. O&M--Operations and maintenance. ITC--Investment tax credits. DD&A--Depreciation, depletion, and amortization.					

Combined Product of All Survey Work (David 2001, Diego 2001, James 2001-2002)

State	DCF	Utility Specific Risk Premium	CAPM
Alabama - PSC Mary Martin (334) 242-9848 Contacted by: D. Stein	<u>Adversary Staff</u> Constant growth D0*(1+g) using BR, and calculated earnings/dividend growth from VL estimates; 3 month average prices as well as spot price. See testimony of John Legler, on behalf of Adversary Staff for Georgia Power, cross referenced w/ testimony in other jurisdictions	<u>Adversary Staff</u> Average risk premium calculated from CAPM equity estimates less utility bond yields, 30 year treasuries See testimony of John Legler, on behalf of Adversary Staff for Georgia Power, cross referenced w/ testimony in other jurisdictions	No CAPM <u>Adversary Staff</u> Beta Value Line No adjustments Risk Free Current Yield on 30-year T-Bond Risk Premium Ibbotson Yearbook
Arizona - ACC Joel Reiker (602) 542-0823 Contacted by: D. Stein	Constant growth D0*(1+g) using BR, and calculated earnings/dividend growth from VL estimates; 3 month average prices as well as spot price. From most recent order in gas case, using John Legler as a witness…cross referenced w/ testimony in other jurisdictions.	Average risk premium calculated from CAPM equity estimates less utility bond yields, 30 year treasuries From most recent order in gas case, using John Legler as a witness…cross referenced w/ testimony in other jurisdictions.	Beta Value Line of all similar companies No adjustments Risk Free Yield 30-day T-bill Yield 5-year T-Notes Yield 30-year T-Bond Risk Premium Ibbotson Yearbook Calculate a CAPM for each of the Risk Free rates. From those calculations chose the result that is the most reasonable. (Tends to be 5-year)
	Constant growth using 8 week avg price	Comparison between implied risk premium in	Beta Average of a variety of published betas

Arkansas - PSC Rob Brunner (501) 682-5986 rob_brunner@psc.state.ar.us Contacted by: D. Stein D. Ochoa Doc. Research by J. Heffner	in yield calc. (D/P)(1+.25g) Using VL BV growth estimates as well as BR+VS See testimony in 99-009-U New rate case w/ Arkla Docket 01-243-0	current Staff recommendation and risk premiums implied from past staff. RP calculated from recommended ROE and 30 year treasuries	Value Line Primary source S&P, Merrill Lynch also used Risk Free 5-10 year treasury Depends on yield curve as to which is used Take conservative approach Risk Premium Corporate yield and adjustment by beta Try to use multiple models when calculating ROE
California - CPUC No contact as of 12/01 Jan Reid is the ROE witness	Commission Staff do not produce models/testimony. <u>Office of Ratepayer Advocate</u> Constant growth DCF. 3 month averages of high and low prices, D1=(Sum of last 4 divs)(1+g). 5 and 10 year historical dividend growth, 5 year historical earnings growth, Zacks forecasted earnings examined. Only used forecasted growth in recommendation. See 2000 Energy Cost of Capital Recommendations, Docket A99-11-003, 3/26/00.	Commission Staff do not produce models/testimony. <u>Office of Ratepayer Advocate</u> Simple 5 and 10 year average risk premium over 30 year Treasuries	Commission Staff do not produce models/testimony. <u>Office of Ratepayer Advocate</u> Beta Value Line Risk Premium Ibbotsons historical to be consistent w/ Commission decisions but argues for a forward looking risk premium ala Cornell. Risk Free DRI forecast of 30 year Treasury Bonds
Connecticut - DPUC Steve Cadwallader (860) 827-2629 Contacted by: D. Stein J. Heffner	Constant growth version. Yield calc from avg daily price for 1 month, K_e=(1+.5(avg DPS,EPS growth) *(D/P)+g; g=DPS,EPS calculated from VL See Docket 98-01-02, Decision made in 2/5/99 Prosecutorial Staff	30 yr time period. Ibbotsons large company stocks-utilty bond yields. Resulting average risk premium added to forecasted utility yield (Blue Chip)	Beta Value Line Risk Free 3 month - 1 year Treasury bills Risk Premium Ibbotson

Doc. Research by J. Heffner	James Sutphin		*Never heard of Fisher Kamin All calculations are an average from proxy group CAPM used as a check for DCF calculations
Colorado-COPUC Sandra Johnson-Jones Financial Analyst (303) 894-2910 Sandy.Jones@dora.state.co.us Contacted by: D. Stein J. Heffner Doc. Research by J. Heffner	Constant Growth DCF See Decision C99-579, Docket 98S-518G, Public Serv. Colorado New rate case to be filed 2Q 2002 by Public Serv. Colorado	No Risk Premium	Beta Publicly available info Value Line investment survey. I/B/E/S Risk Premium Ibbotson year in summary (Geometric mean large company stock-Geometric mean intermediate government bonds) Risk Free Rate Selected interest rate from monthly Federal Reserve statistical release *Never heard of Fisher-Kamin
Delaware - PUC Kevin Sigafoos (302) 739-2612 Contacted by: D. Stein D. Ochoa		Simple average risk premium calculated from DCF estimated ROEs and 5,10,15 yr treasuries.	Beta Proxy group if publicly traded Value Line Risk Free Long-term treasury bond Risk Premium Risk free rate plus an adjustment based on relative risk of the company *Never heard of Fisher-Kamin Primarily focus on DCF calculations Must evaluate all models that are presented in company case filings Question how much weight to apply to each model
Dist. of Columbia – PSC Norman Reiser	DCF Only	No Risk Premium	Commission strictly relies on DCF Companies may use CAPM to justify their arguments

(202) 626-5136 Contacted by: D. Stein			
Florida - PSC Peter Lester (850) 413-6467 Contacted by: D. Stein	Two Stage DCF using avg high and low price for 1 month. Near term growth from Value-Line. Terminal growth is BR using VL forecast	DCF estimate of ROE – 30 year bond	Beta Value Line No further adjustments Risk Premium Simple DCF using earnings & dividend growth. 800 proxy group of companies with moderate growth 1-19% that pay dividends
Georgia - PSC No Contact as of 12/01 Doc. Research by J. Heffner	Constant growth DCF. D1=current div(1+g). Growth rates used are BR growth, EPS and DPS calculated growth from V-L. 3 month avg prices as well as last closing price in the period. See Testimony in Docket 14000-U, Georgia Power. 10/12/01	CAPM estimate of ROE – 30 year bond, utility yield.	Beta Value Line Risk Premium Ibbotsons historical as well as expected calculated from DCF of V-L forecasted market info less the risk free rate Risk Free 30 year Treasury Bonds
Idaho – IPUC Terri Carlock Supervisor Acct Sect. – Util. Div. (208) 334-0300 tcarloc@puc.state.id.us Contacted by: D. Stein, J. Heffner	DCF (constant growth) is primary model, although two stage model used in Avista ratecase (98)	No Risk Premium	No CAPM
Illinois - ICC Allen Pergozen (217) 785-5418 Contacted by: D. Stein Doc. Research by J. Heffner	DCF (constant growth) Using EPS from Zacks, IBES See Docket 99-01117, Commonwealth Edison. Testimony.	No Risk Premium	Beta Value Line Risk Free Implied Yields from U.S. T-Bill and Bond futures contracts. Compare w/ forecasted implied risk free rate (1+real risk free rate)(1+Inflation)-1 and (1+real GDP)(1+Inflation)-1. Risk Premium DCF on dividend paying companies in S&P

			500 to get return on market Risk free rate is the one calculated previously No Ibbotson *Never heard of Fisher-Kamin
Indiana - IURC Jane Steinhaur (317) 232-4244 Contacted by: D. Stein	Commission Staff do not produce models/testimony. Calculations done on a review basis of what companies bring before commission Average of models filed establishes a range of required rate of return.	Commission Staff do not produce models/testimony. Calculations done on a review basis of what companies bring before commission Average of models filed establishes a range of required rate of return.	Commission Staff do not produce models/testimony. Calculations done on a review basis of what companies bring before commission Average of models filed establishes a range of required rate of return.
Iowa - IUB Chancy Bittner (515) 282-5136 Contacted by: J. Heffner	Commission Staff do not produce models/testimony. ROE issue stipulated since early '90s. At that time Staff was using the FERC model (single stage) w/6 mo avg prices and D1=D0(1+.5g) Growth rates used were 10 year historic dividend growth and 10 year historic internal growth (BR)	Commission Staff do not produce models/testimony. ROE issue stipulated since early '90s. Risk Premium model based on spread above A-Rated utility bonds. Range approx. 250-450 basis points. Focus has shifted from the DCF to the Risk Premium model in recent years.	Commission Staff do not produce models/testimony. ROE issue stipulated since early '90s. No CAPM Docket No. RPU-91-8 "The board does not have any substantial confidence in the credibility of the CAPM because of it volatility and strong dependence on the beta estimate"

Kansas-KCC No Contact Established Doc. Research by J. Heffner	Semi-Annual DCF K_e=(1+.5g)(D/P)+g Growth Rates Forecasted EPS – VL BR Calculated from VL No weight to Forecasted DPS as utilities are experiencing abnormal growth	No Risk Premium analysis	Beta: Value Line No Adjustment Risk Free Spot yield on 90 day T-Bill rates Risk Premium Ibbotson's (1926-1999) Arithmetic Average (Annual Large Company Stock Total Returns – Annual T-Bill Total Returns) Source: Docket 01-WRSE-436-RTS – Testimony of Adam Gatewood, KCC Staff, Utilities Division,. April 6, 2001
Kentucky - PSC John Rogness (502) 564-3940 x229 Contacted by: D. Stein	Commission Staff do not produce models/testimony. <u>Attorney General</u> Constant and Two stage DCF.	Commission Staff do not produce models/testimony. <u>Attorney General</u> Risk Premium, additive over bond yields.	Commission Staff do not produce models/testimony. <u>Attorney General</u> Beta: Published – from Value Line or S&P Risk Premium Total Market return- Risk free rate Risk free comes from government securities Recommended long term T-bills
Louisiana - PSC Brian McManus Economist Manager LPSC Division of Economics and Rates Analysis (225) 342-2720 brianm@lpsc.org	DCF	No Risk Premium	Beta: Value Line No Adjustment Risk Free Long-term treasury rate Risk Premium Historical Ibbotson Projected from Value Line Average of the 2 premiums is used

Maine -PUC Richard Kivela (207) 288-1562 Contacted by: D. Stein	Quarterly and annual versions of constant growth, mostly quarterly. Average of 20 business day stock prices, S&P stock guide indicated dividend (1+g), and IBES growth Verify See Docket 97-580 Order dated 3/19/99	No Risk Premium	Beta Value Line peer group average No adjustments Risk-Free 30-year Treasury bond yield Risk premium Calculate DCF on S&P 500 companies that pay dividends. Occasional use of Ibbotson Can have multiple calculations, then take an average. *Heard of Fisher-Kamin but has no idea of what it does CAPM is used as a back up model Beta's are historical Ibbotson isn't forward looking Don't rely on CAPM
Maryland – PSC No Contact as of 12/01 Contacted by: D. Stein	"Horizon" DCF – cash flow terminates in 5 years with stock sold at forecasted price. Uses Value Line forecasted dividends. See Testimony of Charles Larson, Case no. 8829 (2000), 8873 (1997)	No Risk Premium	No CAPM "Also, the Beta in the CAPM approach has been thoroughly discredited as a useful statistical tool, largely because its cooefficient of correlation is so low that the beta is a meaningless number" - Testimony in 8829, 1/27/00
Massachusetts – DTE Mauricio Diaz (617) 305-3664 Contacted by: D. Stein			Beta Parameter group represents company risk used Value Line Average of proxy group's beta from Value Line Risk Premium Premium Yields on 'A' rated utility bonds Value Line ROE avg. – Treasury bond interest rate Take average of above two lines and that will

			be used as risk premium Risk Free 30 year treasury bond interest rate
Michigan - PSC Brian Ballinger (517) 241-6103 blballi@michigan.gov Contacted by: D. Stein	Constant Growth version. Uses 3 month average of monthly average of high and low prices; with most recent quarterly dividend annualized. D1=D0(1+.5g). Growth rate is equally weighted average of IBES, Zacks, and VL EPS, DPS, and BV growth projections (blended)	No Risk Premium	Beta Value line No adjustments Risk Premium Ibbotsons 1958-Present Risk Free Forecasted yields of 30-year Treasury Securities and examination of 13 year securitization bonds by company *Never heard of Fisher Kamin
Minnesota – PUC Clark Kaml (651) 297-4563 clark.kaml@state.mn.us Contacted by: D. Stein	DCF Constant growth	No Risk Premium	No CAPM
Missouri - PSC Contacted by:	DCF Constant growth (primary) See Order for Case# ER-2001-299, Empire District, issued 9/20/2001. Witness: Roberta McKiddy	No Risk Premium	No CAPM

Mississippi - PSC Mike McCool (601) 961-5495 Contacted by: D. Stein			Beta Value Line Strictly from publication Risk Free 3-month average of 30 – year treasury Risk Premium Ibbotson Annual Return on stock – Return on bonds
Montana-PSC Dave Burchett Utility Division (406) 444-6199 Dburchett@state.mt.us Contacted by: D. Stein J. Heffner	Commission Staff do not provide models/testimony.	Commission Staff do not provide models/testimony.	Commission Staff do not provide models/testimony. Commission reviews the methods supplied by the company and the arguments presented by the intervenors and make decision from information before them *Never heard of Fisher-Kamin
Nebraska - PSC John Burvainis (402) 471-3101 Contacted by: D. Stein	Utilities have been deregulated since 1987.	Utilities have been deregulated since 1987.	Outdated information Utilities have been deregulated since 1987.
Nevada-PUCN Ron Knecht Economist (775) 687-6034 ronknecht@aol.com Contacted by: J.Heffner	3 Stage DCF using historic dividend growth and BR+VS for near term (5 yrs), economy growth for terminal, and transitional growth period between (5 yrs). Uses quarterly DCF to determine quarterly ROE then calculates annual ROE.	Risk Premium calculated. No weight given to estimates.	CAPM calculated. No weight given to estimates. Beta Value Line Merrill Lynch Published version No further adjustment Risk Free Ibbotson book Risk Premium Corporate Bond or Long term Government securities over equity.

			*Never heard of Fisher-Kamin (Lew DeWeese)
New Hampshire - PSC Andrew Kosnaski (603) 271-6047 Contacted by: D. Stein			Beta Value Line No adjustment Simple average of proxy group Risk Free 10 year treasury 20 trading day average Risk Premium Historical- Commission Value Line Database DCF of S&P 500 Any of the above three may be used *Never heard of Fisher-Kamin
New Jersey - BPU Mark Beyer (973) 648-3414 Contacted by: D. Stein	Primarily focus on DCF now		Beta Value Line No adjustment Risk Free Treasury Securities 7 year Risk Premium *Never heard of Fisher-Kamin CAPM was used in past
New Mexico-NMPRC Jim Brack Utility Division (505) 827-6982 Jim.Brack@state.nm.us Contacted by: D. Stein J. Heffner	DCF only	No Risk Premium	No CAPM

New York – PSC Jeff Hogan (518)486-2839 Contacted by: D. Stein	ROE for DCF calculated many ways. Average of calculations used for formula DCF Calculations – weighted 2/3	No Risk Premium	Beta Value Line Don't do regression May use proxy group Risk Premium Merrill Lynch or some publication Try to reduce element of subjectiveness Risk Free Average of 10 and 30 year government securities returns CAPM calculations – weighted average 1/3
North Carolina - NCUC Dave Creasy (919) 733-2435 Contacted by: D. Stein			Haven't had a rate case in over ten years CAPM was a piece of structure Commission/Staff never actually calculated CAPM Took information from all witnesses and drew their own conclusion from that. Not relying more on one specific model
North Dakota-PSC Mike Diller (701) 328-4079 mrd@oracle.psc.state.nd.us Contacted by: J. Heffner	Staff hires an outside consultant for rate cases. Constant Growth DCF using earnings growth from Zacks. D1=Current Dividend(1+.5g). Avg. of 50 daily prices (CBS Market Watch)	No Risk Premium	
Ohio - PUC Steve Chaney (614) 466-6029 Contacted by: D. Stein	Three Stage DCF. Earnings growth (Zacks, V-L, Multex) for 5 years, final growth in year 25 using GNP growth, transitional stage using incremental difference.	No Risk Premium	Beta Value Line - No Regression Risk premium Ibbotson Total return-Long term government bonds *Never heard of Fisher Kamin
Oklahoma - OCC Glen Gregory			

g.gregory@occmail.occ.sta te. ok.us **Contacted by: J. Heffner**			
Pennsylvania - PUC Andy O'Donnell (717) 787-8084 Contacted by: D. Stein	Single Stage using average of spot yield and 52 week average yield. Growth rates from S&P, Zacks, IBES, and Value Line. See Order dated 8/26/99 - City of Lancaster (Water) and assorted other orders	No Risk Premium	No CAPM- Haven't used in some time Beta and Premiums are too controversial CAPM not given credibility in commission Need to keep arguments consistent
Rhode Island – RIPUC Tom Massarow (401) 222-3500 x 106 Contacted by: D. Stein	DCF Only	No Risk Premium	No CAPM
South Carolina - PSC Jim Spearman (803) 896-5142 Contacted by: D. Stein, D. Ochoa		Risk Premium, additive over bond yields.	Beta Merrill Lynch Value Line No further adjustment Risk free Government rate on 30 or 10-year treasury 10-year is benchmark Risk Premium Ibbotson Calculate Market Returns for industry more weight on longer treasuries
South Dakota -PUC Dave Jacobsen Analyst (605) 773-3201	Staff hires an outside consultant for rate cases. Constant Growth and Three Stage DCF	No Risk Premium	Beta Value Line Risk Premium Calculated from Ibbotson (18 year geometric

david.jacobson@state.sd.us Contacted by: D. Stein J. Heffner	model (DDM). Constant growth using D1=D0(1+.5g)/P0, growth used IBES, VL-EPS,DPS,BV,% Retained to Common Equity. Three Stage uses IBES (4 years), 15 year transition period, then long term growth		non-overlapping for the entire period, and excluding 1961-present)
Texas - PUC Slate Cutter (512) 936-7437 slade.cutter@puc.state.tx.us Contacted by: D. Stein, D.Ochoa, J. Heffner	Multi (3) stage model.-IRR method.. Near term using avg of 5 year div projections calculated from V-L, Goldman Sachs, Merril-Lynch. Long term avg Zacks earnings growth rates for industry and S&P500. Transition stage of incremental growth lasts 5 years.	Regression of Authorized ROE's and interest rates, but applied slightly in slightly different manner. Applied to change in average bond yield to find necessary adjustment to avg risk premium and then applied to current avg. bond yield.	Beta Value Line No adjustments Risk Free Three month average of 30-year Treasury Bond Risk Premium Arithmetic mean return value between common stocks and long-term government bonds as publised in Ibbotson *Heard of Fisher Kamin. Never Used it CAPM used as check of DCF
Utah - PSC Rich Collins Commission Advisory Staff (801) 530-6770 Contacted by: D. Stein William (Artie) Powell Utility Economist Dept. of Public Utilities Contacted by: J. Heffner	Commission Staff do not provide models/testimony. <u>DPU Staff</u> Constant and Non-constant (Terminal Value DCF) Using 4*Last Div, Average of 3 month daily prices. Growth rates are 1) div growth calculated from V-L; 2) eps growth is weighted avg of V-L, Zacks – more heavily weighted to Zacks (several analysts in consensus)	Commission Staff do not provide models/testimony. <u>DPU Staff.</u> No Risk Premium	Commission Staff do not provide models/testimony. <u>DPU Staff</u> Beta Value Line average of comparable utilities Risk Free Mid-Point of 13 week average on 30-year treasury bonds (from V-L) Risk Premium Long-run average and end points of 95% conf. interval of stock market returns (ala John Cochrane, NBER working paper 1997: 3%, 8%, 11%) CAPM not relied on heavily.

Vermont - PSB Ray Collander (802) 828-2325 Contacted by: D. Stein Doc. Research by J. Heffner	Most recent decisions (2001) have abandoned the traditional rate making framework to keep utilities (GMP, Central VT Public Service) financially healthy.		CAPM only used as comparative. Don't recall last calculations Has been five years since last rate case.
Washington-WUTC Rolland Martin (360) 664-1304 Contacted by: D. Stein Doc. Research by J. Heffner	Constant Growth DCF (6 mo avg price), (1+.5g) model 5,10 yr historical EPS/DPS/BV as well as EPS forecasts from VL, Zacks, IBES	No Risk premium	Not used
West Virginia - PSC Diane Calbert (304) 340-0369 Contacted by: D. Stein			Beta Value Line No adjustments Risk Free 13 Week average of Treasury Bills Forecast Value Line Forecast Blue Chip stock Average of all three is used as Risk free rate Risk Premium Ibbotson
Wisconsin - PSC Randy Pilo (608) 267-1474 Contacted by: D. Stein *Lois Hubert* *(608) 267-2210* *Current witness*	Constant Growth DCF	Historical Avg of in-state authorized ROEs minus 30, 10 year treasuries, AA utility bonds	Beta Value Line No further adjustment Risk Premium Ibbotson - Short term bill and 30 year treasury bond. Calculate a CAPM for each government security then take an average of both to get Required Rate of return

			*Never heard of Fisher-Kamin
Wyoming-PSC Bryce Freeman Lead Rate Analyst (307) 777-5742 Contacted by: D. Stein *Marci Norby* *(307) 777-5270* *Rate Analyst* *mnorby@state.wy.us* Contacted by: J. Heffner Doc. Research by J. Heffner	Constant growth DCF Growth rate = weighted average of DPS, EPS, and Book Value growth from Value Line	Subtractive. 5 year averageannual risk premium calculated from V-L utility industry ROE and 30 year treasuries (Fed database) See M. Norby testimony in Docket 20000-CR-00-62.	Beta Value Line No adjustments Risk Free 30-year Treasury Bond Risk Premium Measure of (Market Return – Government Return)

Regulatory Research Associates, Inc. REGULATORY FOCUS RRA
30 MONTGOMERY STREET JERSEY CITY, NEW JERSEY 07302 (201) 433-5507

January 6, 2006

STATE REGULATORY EVALUATIONS

As part of RRA's regulatory research effort, we evaluate the regulatory climates of 49 states and the District of Columbia. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by the jurisdiction's electric, gas, and telephone utilities. Each evaluation is based upon our studies of the numerous factors affecting the regulatory process in the state, and is changed as major events occur which cause us to modify our view of the regulatory risk accruing to the ownership of utility securities in that individual jurisdiction. We also review our evaluation when we issue State Regulatory Reviews, and when we publish quarterly comparative evaluations. The majority of factors that we consider are discussed in *Focus Notes*, State Regulatory Reviews, Final Reports, or Regulatory Updates. We also consider information obtained from contacts with commission, company, and government personnel in the course of our research. The final evaluation reflects our assessment of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative, and court actions.

RRA maintains three principal rating categories: Above Average, Average, and Below Average. We endeavor to maintain an approximately equal number of ratings above the average and below the average. Within the principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger rating; 2, a mid-range rating; and, 3, a weaker rating.

Our last "State Regulatory Evaluations" was published October 5, 2005, at which time, we noted two ratings changes; in response to increased politicization of the regulatory process, we lowered our rating of Illinois to Below Average/1 from Average/3 (see FN 9/23/05); and, in recognition of constructive rate decisions for three of the major investor-owned utilities, we raised our rating of Georgia regulation to Average/1 from Average/2. At this time we are raising our rating of the California regulatory climate to Average/2 from Average/3 in recognition of more constructive policies, in particular, the California Public Utilities Commission's December 2005 authorization of above-average equity returns for 2006 for the state's major energy utilities (see the Final Report 12/29/05). In addition, we are lowering our rating of Oregon regulation to Average/2 from Average/1 due to the potential negative ramifications of Senate Bill (SB) 408, enacted in September 2005, that requires the flow through of consolidated tax savings to ratepayers (FN 1/6/06).

Our state regulatory evaluations are not to be confused with our "Tier" classifications, in which we categorize 49 states and the District of Columbia based on relative progress toward electric industry restructuring. For further detail, refer to the October 20, 2004 Special Report entitled *Electric Industry Restructuring Update*, which is revised weekly on our website ***www.rra-focus.com***.

Above Average	Average	Below Average
1	**1**	**1**
	Delaware Georgia Iowa Maryland Massachusetts South Carolina Tennessee Washington	Illinois Montana Nevada Texas Vermont West Virginia
2	**2**	**2**
Alabama Florida Indiana North Carolina Wisconsin	California* District of Columbia Hawaii Kentucky Michigan Minnesota Nebraska New Jersey New York North Dakota Ohio Oklahoma Oregon** Rhode Island South Dakota	
3	**3**	**3**
Mississippi Virginia	Arizona Arkansas Colorado Connecticut Idaho Kansas Louisiana Maine Missouri New Hampshire New Mexico Pennsylvania Utah Wyoming	

ALPHABETICAL LISTING

Alabama - AA/2
Arizona - A/3
Arkansas - A/3
California – A/2*
Colorado - A/3
Connecticut - A/3
Delaware - A/1
Dist. of Col. - A/2
Florida - AA/2
Georgia - A/1
Hawaii - A/2
Idaho - A/3
Illinois - BA/1
Indiana - AA/2
Iowa - A/1
Kansas - A/3
Kentucky - A/2
Louisiana - A/3
Maine - A/3
Maryland - A/1
Massachusetts - A/1
Michigan - A/2
Minnesota - A/2
Mississippi - AA/3
Missouri - A/3
Montana - BA/1
Nebraska – A/2
Nevada – BA/1
New Hampshire – A/3
New Jersey - A/2
New Mexico - A/3
New York - A/2
North Carolina - AA/2
North Dakota - A/2
Ohio - A/2
Oklahoma - A/2
Oregon - A/2**
Pennsylvania - A/3
Rhode Island - A/2
South Carolina - A/1
South Dakota - A/2
Tennessee - A/1
Texas - BA/1
Utah - A/3
Vermont - BA/1
Virginia - AA/3
Washington - A/1
West Virginia - BA/1
Wisconsin - AA/2
Wyoming - A/3

* Revised upward since October 5, 2005.
** Revised downward since October 5, 2005.

December 31, 2007

(A)	Ledger (B)	Type (C)	Description (D)	Issue Date (E)	Maturity Date (F)	Term (G)	Coupon (H)	Gross Proceeds (I)	DD&E Issue Costs (J)		Call Premium & Unamort. DD&E of Refunded Issue (K)		Net Proceeds (L) [I-J-K]	Embedded Cost (M)	Net to Gross Rate (N)	Face Amount Outstanding (O)	Net Outstanding (P) [N*O]	Face Amount Weight (Q) [O/Total]	PGE Weighted Rate (R) [Q*M]	Staff Embedded Cost (S)	Change from PGE's Embedded (S-M)
1	G11514	FMB	5.6675% Series	28-Oct-02	25-Oct-12	10	5.080%	$100,000,000	$817,683	0.82%	$0		$99,182,317	7.420%	99.182%	$100,000,000	$99,182,317	9.578%	0.711%	5.1858%	-2.23417%
2	G11515	FMB	5.279% Series	08-Apr-03	01-Apr-13	10	5.080%	$50,000,000	$408,842	0.82%	$0		$49,591,158	6.434%	99.182%	$50,000,000	$49,591,158	4.789%	0.308%	5.1856%	-1.24817%
3	G11516	FMB	5.625% Series	04-Aug-03	01-Aug-13	10	5.450%	$50,000,000	$408,842	0.82%	$1,946,809		$47,644,349	5.734%	95.289%	$50,000,000	$47,644,349	4.789%	0.275%	6.0859%	0.35156%
4	G11517	FMB	6.750% Series	04-Aug-03	01-Aug-23	20	6.575%	$50,000,000	$521,342	1.04%	$1,946,809		$47,531,849	6.846%	95.064%	$50,000,000	$47,531,849	4.789%	0.328%	7.0387%	0.19270%
5	G11518	FMB	6.875% Series	04-Aug-03	01-Aug-33	30	6.700%	$50,000,000	$521,342	1.04%	$1,946,809		$47,531,849	6.958%	95.064%	$50,000,000	$47,531,849	4.789%	0.333%	7.0998%	0.14176%
6	G11501	Series MTN	9.31% Series	12-Aug-91	11-Aug-21	30	9.310%	$20,000,000	$176,577	0.88%	$0		$19,823,423	9.399%	99.117%	$20,000,000	$19,823,423	1.916%	0.180%	9.3986%	-0.00039%
7		FMB	6.31% Series	01-Apr-06	01-Apr-36	30	6.310%	$175,000,000	$1,125,000	0.64%	$0	20	$173,875,000	6.080%	99.357%	$175,000,000	$173,875,000	16.762%	1.019%	6.3583%	0.27825%
7.5		FMB	6.26% Series	01-Apr-06	01-Apr-31	25	6.260%	$100,000,000	$750,000	0.75%	$0	20	$99,250,000	6.080%	99.250%	$100,000,000	$99,250,000	9.578%	0.582%	6.3201%	0.24008%
8		FMB	6.5% Series	15-Jun-07	15-Jun-17	10	5.770%	$100,000,000	$750,000	0.75%	$0	19	$99,250,000	6.565%	99.250%	$100,000,000	$99,250,000	9.578%	0.629%	5.8702%	-0.69497%
9	G40027	Notes	7.875% Series	13-Mar-00	15-Mar-10	10	7.875%	$149,250,000	$1,472,800	0.99%	$1,266,000	17	$146,511,200	8.128%	98.165%	$149,250,000	$146,511,200	14.295%	1.162%	8.1468%	0.01831%
10	G21186	PCB	Brdmn 98A Fixed	28-May-98	01-May-33	35	5.200%	$23,600,000	$85,850	0.36%	$1,267,030	5,16,18	$22,247,120	5.544%	94.267%	$23,600,000	$22,247,120	2.260%	0.125%	5.5742%	0.03325%
11	G21185	PCB	Clstrp 98A Fixed	28-May-98	30-Apr-33	35	5.200%	$97,800,000	$355,835	0.36%	$1,617,373	6,16,18	$95,826,792	5.336%	97.982%	$97,800,000	$95,826,792	9.367%	0.500%	5.3278%	-0.00822%
12	G21184	PCB	Colstrip 98B Fixed	28-May-98	30-Apr-33	35	5.450%	$21,000,000	$76,420	0.36%	$438,143	16,18	$20,485,437	5.620%	97.550%	$21,000,000	$20,485,437	2.011%	0.113%	5.6106%	-0.00936%
13	G21191	PCB	Trojan 85A Fixed	01-Jul-98	01-Apr-10	25	4.800%	$20,200,000	$218,352	1.08%	$244,162	16	$19,737,486	5.058%	97.710%	$20,200,000	$19,737,486	1.935%	0.098%	4.9608%	-0.09717%
14	G21193	PCB	Trojan 85B Fixed	01-Jul-98	01-Jun-10	25	4.800%	$16,700,000	$180,519	1.08%	$184,473	16	$16,335,008	5.046%	97.814%	$16,700,000	$16,335,008	1.600%	0.081%	4.9534%	-0.09260%
15	G21195	PCB	Trojan 90A Fixed	01-Jul-98	01-Aug-14	16	5.250%	$9,600,000	$103,771	1.08%	$184,980	16	$9,311,249	5.537%	96.992%	$9,600,000	$9,311,249	0.919%	0.051%	5.5356%	-0.00129%
16	G21196	PCB	Troj Ser 1990B-Fixed	15-Dec-90	15-Dec-14	24	7.125%	$5,100,000	$163,234	3.20%	$0		$4,936,766	7.412%	96.799%	$5,100,000	$4,936,766	0.488%	0.036%	7.4123%	0.00034%
17	G21123	PCB	Coyote 96 Float	01-Dec-96	01-Dec-31	35	3.500%	$5,800,000	$159,350	2.75%	$0		$5,640,650	3.671%	97.253%	$5,800,000	$5,640,650	0.556%	0.020%	3.6395%	-0.03155%
			Loss on Reacquired Debt								$0		$0								
			Total Debt					$1,044,050,000	$8,295,758		$11,042,588		$1,024,711,654			$1,044,050,000	$1,024,711,654	100.00%	6.3121%		

Cost of LT Debt
(includes loss from reacquired)

	Losses on Reacquired Debt	Reacquired	Gross Proceeds	Total Gain/Loss to Amortize	Annual Expense	summary of adjustments:
Y61181	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.

Single-Stage DCF Model Results — UE 180 — Schedule 1 - Single Stage Model

		[A]	[B]	[C]	[D]	[E]
COMPANY	TICKER	Next 12-months Dividend	Current Price	Dividend Yield	Growth Rate	Selected Companies
Alliant Energy	LNT	1.18	$34.96	3.38%	4.40%	7.78%
Amer. Elec. Power	AEP	1.54	$34.88	4.42%	3.51%	7.93%
Consol. Edison	ED	2.31	$45.14	5.12%	3.41%	8.53%
Empire Dist. Elec.	EDE	1.28	$21.54	5.94%	3.38%	9.32%
Energy East Corp.	EAS	1.21	$24.03	5.03%	4.27%	9.30%
IDACORP, Inc.	IDA	1.2	$34.99	3.43%	4.79%	8.22%
MGE Energy	MGEE	1.38	$31.52	4.38%	6.00%	10.38%
NSTAR	NST	1.24	$29.14	4.25%	4.50%	8.75%
OGE Energy	OGE	1.35	$34.67	3.89%	3.50%	7.39%
Progress Energy	PGN	2.46	$42.82	5.74%	3.49%	9.24%
Southern Co.	SO	1.56	$32.60	4.79%	4.70%	9.49%
Wisconsin Energy	WEC	0.94	$40.79	2.30%	6.80%	9.10%
WPS Resources	WPS	2.3	$50.00	4.60%	4.80%	9.40%
Xcel Energy Inc.	XEL	0.89	$19.33	4.60%	4.86%	9.46%
AVERAGE		**$1.49**	**$34.03**	**4.42%**	**4.46%**	**8.88%**
MEDIAN		**$1.32**	**$34.78**	**4.51%**	**4.45%**	**9.17%**

[A] Value Line Summary and Index, July 21, 2006
[B] Most current stock quotes provided by MSN Money, www.moneycentral.msn.com
[C] Dividend rate divided by market price [C] / [B]
[D] Growth Rates from average of Kiplinger's; Firstcall; Zack's; Reuters; Value Line
[E] Dividend Yield + Growth [C] + [D]

Single-Stage DCF Model, Sensitivity Analysis — UE 180 — Schedule 1A - Sensitivity Analysis

COMPANY	TICKER	Next 12-months Dividend	Current price	Div Yield	Minimum Analyst Estimate	COE Results	Maximum Analyst Estimate	COE Results
Alliant Energy	LNT	$1.18	$34.96	3.38%	2.50%	5.88%	6.50%	9.88%
Amer. Elec. Power	AEP	$1.54	$34.88	4.42%	2.00%	6.42%	6.00%	10.42%
Consol. Edison	ED	$2.31	$45.14	5.12%	1.50%	6.62%	4.00%	9.12%
Empire Dist. Elec.	EDE	$1.28	$21.54	5.94%	2.50%	8.44%	5.00%	10.94%
Energy East Corp.	EAS	$1.21	$24.03	5.03%	4.00%	9.03%	4.50%	9.53%
IDACORP, Inc.	IDA	$1.20	$34.99	3.43%	4.50%	7.93%	5.00%	8.43%
MGE Energy	MGEE	$1.38	$31.52	4.38%	6.00%	10.38%	6.00%	10.38%
NSTAR	NST	$1.24	$29.14	4.25%	2.50%	6.75%	5.00%	9.25%
OGE Energy	OGE	$1.35	$34.67	3.89%	3.00%	6.89%	5.50%	9.39%
Progress Energy	PGN	$2.46	$42.82	5.74%	2.87%	8.61%	4.00%	9.74%
Southern Co.	SO	$1.56	$32.60	4.79%	4.00%	8.79%	5.00%	9.79%
Wisconsin Energy	WEC	$0.94	$40.79	2.30%	4.00%	6.30%	8.00%	10.30%
WPS Resources	WPS	$2.30	$50.00	4.60%	4.50%	9.10%	5.00%	9.60%
Xcel Energy Inc.	XEL	$0.89	$19.33	4.60%	4.00%	8.60%	5.00%	9.60%
AVERAGE		**$1.49**	**$34.03**	**4.42%**	**3.42%**	**7.84%**	**5.32%**	**9.74%**
MEDIAN		**$1.32**	**$34.78**	**4.51%**	**3.50%**	**8.19%**	**5.00%**	**9.67%**

150-Year Horizon DCF **UE 180** **Schedule 2 - Sensitivity Range Analysis - Low** ===> to year 150

HADAWAY COMPANIES	(ticker)	IRR	[1] Current Price [A]	[2] Dividend EOY 1 [B]	[3] Dividend EOY 2 [B]	[4] Dividend EOY 3 [B]	[5] Dividend EOY 4 [B]	LT Growth Dividend EOY 5 [C]	Dividend EOY 6	Dividend EOY 7	Dividend EOY 8	Dividend EOY 9	Dividend EOY 10
Alliant Energy	LNT	6.60%	($33.59)	$1.15	$1.25	$1.35	$1.45	$1.55	$1.59	$1.63	$1.67	$1.71	$1.75
Amer. Elec. Power	AEP	7.09%	($33.87)	$1.48	$1.60	$1.70	$1.80	$1.90	$1.94	$1.98	$2.02	$2.06	$2.10
Consol. Edison	ED	6.64%	($43.70)	$2.30	$2.32	$2.34	$2.36	$2.38	$2.42	$2.45	$2.49	$2.53	$2.56
Empire Dist. Elec.	EDE	8.23%	($20.49)	$1.28	$1.28	$1.28	$1.28	$1.28	$1.31	$1.34	$1.38	$1.41	$1.45
Energy East Corp.	EAS	9.04%	($23.70)	$1.18	$1.24	$1.29	$1.35	$1.40	$1.46	$1.51	$1.57	$1.64	$1.70
IDACORP, Inc.	IDA	7.48%	($33.68)	$1.20	$1.20	$1.20	$1.20	$1.20	$1.25	$1.31	$1.37	$1.43	$1.50
MGE Energy	MGEE	9.90%	($29.63)	$1.38	$1.39	$1.41	$1.42	$1.44	$1.53	$1.62	$1.72	$1.82	$1.93
NSTAR	NST	7.25%	($28.21)	$1.21	$1.26	$1.34	$1.42	$1.50	$1.54	$1.58	$1.62	$1.66	$1.70
OGE Energy	OGE	6.88%	($34.18)	$1.33	$1.36	$1.41	$1.45	$1.50	$1.55	$1.59	$1.64	$1.69	$1.74
Progress Energy	PGN	8.44%	($42.26)	$2.44	$2.50	$2.54	$2.58	$2.62	$2.70	$2.77	$2.85	$2.93	$3.02
Southern Co.	SO	9.03%	($31.80)	$1.54	$1.62	$1.71	$1.79	$1.88	$1.96	$2.03	$2.11	$2.20	$2.29
Wisconsin Energy	WEC	6.29%	($39.39)	$0.92	$0.96	$1.01	$1.05	$1.10	$1.14	$1.19	$1.24	$1.29	$1.34
WPS Resources	WPS	15.55%	($18.98)	$2.28	$2.32	$2.36	$2.40	$2.44	$2.55	$2.66	$2.78	$2.91	$3.04
Xcel Energy Inc.	XEL	8.92%	(18.98)	$0.88	$0.93	$0.99	$1.04	$1.10	$1.14	$1.19	$1.24	$1.29	$1.34
AGGREGATE		8.31%	($432.46)	$20.57	$21.23	$21.92	$22.60	$23.29	$24.06	$24.86	$25.69	$26.55	$27.45
Average		8.38%											
Stdev		2.34%						3.04%					
Min		6.29%											
Max		15.55%											
Median		7.86%											
25 percentile		6.93%											
75 percentile		9.00%											

Sources:
[A] Most current stock quotes provided by MSN Money, www.moneycentral.msn.com
[B] Value Line Data (See Schedule 3)
[C] Long-term growth is the input variable, based on consensus analyst growth expectations.

150-Year Horizon DCF **UE 180**

Schedule 2A - Sensitivity Range Analysis - High

COHORT COMPANY DATA

SELECTED FINANCIAL DATA

HADAWAY COMPANIES	(ticker)	IRR	[1] Current Price	[2] Dividend EOY 1	[3] Dividend EOY 2	[4] Dividend EOY 3	[5] Dividend EOY 4	LT Growth Dividend EOY 5	Dividend EOY 6	Dividend EOY 7	Dividend EOY 8	Dividend EOY 9	===> to year 150 Dividend EOY 10
			[A]	[B]	[B]	[B]	[B]	[C]					
Alliant Energy	LNT	10.04%	($33.59)	$1.15	$1.25	$1.35	$1.45	$1.54	$1.64	$1.75	$1.87	$1.99	$2.12
Amer. Elec. Power	AEP	10.45%	($33.87)	$1.48	$1.60	$1.70	$1.80	$1.91	$2.02	$2.14	$2.27	$2.41	$2.55
Consol. Edison	ED	8.84%	($43.70)	$2.30	$2.32	$2.34	$2.36	$2.45	$2.55	$2.65	$2.76	$2.87	$2.99
Empire Dist. Elec.	EDE	10.47%	($20.49)	$1.28	$1.28	$1.28	$1.28	$1.34	$1.41	$1.48	$1.56	$1.63	$1.72
Energy East Corp.	EAS	9.48%	($23.70)	$1.18	$1.24	$1.29	$1.35	$1.41	$1.47	$1.54	$1.61	$1.68	$1.75
IDACORP, Inc.	IDA	8.06%	($33.68)	$1.20	$1.20	$1.20	$1.20	$1.26	$1.32	$1.39	$1.46	$1.53	$1.61
MGE Energy	MGEE	10.06%	($29.63)	$1.38	$1.39	$1.41	$1.42	$1.51	$1.60	$1.70	$1.80	$1.90	$2.02
NSTAR	NST	9.33%	($28.21)	$1.21	$1.26	$1.34	$1.42	$1.49	$1.57	$1.64	$1.73	$1.81	$1.90
OGE Energy	OGE	9.11%	($34.18)	$1.33	$1.36	$1.41	$1.45	$1.53	$1.62	$1.71	$1.80	$1.90	$2.00
Progress Energy	PGN	9.46%	($42.26)	$2.44	$2.50	$2.54	$2.58	$2.68	$2.79	$2.90	$3.02	$3.14	$3.26
Southern Co.	SO	9.86%	($31.80)	$1.54	$1.62	$1.71	$1.79	$1.88	$1.98	$2.08	$2.18	$2.29	$2.40
Wisconsin Energy	WEC	9.99%	($39.39)	$0.92	$0.96	$1.01	$1.05	$1.14	$1.23	$1.33	$1.43	$1.55	$1.67
WPS Resources	WPS	16.12%	($18.98)	$2.28	$2.32	$2.36	$2.40	$2.52	$2.65	$2.78	$2.92	$3.06	$3.22
Xcel Energy Inc.	XEL	11.93%	($18.98)	$0.88	$0.93	$0.99	$1.04	$1.12	$1.21	$1.30	$1.39	$1.50	$1.61
AGGREGATE		10.04%	(432.46)	20.57	21.23	21.92	22.60	23.80	25.05	26.38	27.78	29.26	30.82
Average		10.23%											
Stdev		1.85%											
Min		8.06%											
Max		16.12%											
Median		9.93%											
25 percentile		9.36%											
75 percentile		10.35%											

[A] Most current stock quotes provided by MSN Money, www.moneycentral.msn.com
[B] Value Line Data (See Schedule 3)
[C] Long-term growth is the input variable, based on consensus analyst growth expectations.

150-Year Horizon DCF **UE 180**

Schedule 2B - Analyst Growth Estimates Consensus

COHORT COMPANY DATA

SELECTED FINANCIAL DATA

LT Growth ===> to year 150
Based on Analysts' Estimates *(See Schedule 8)*

GAS COMPANIES	(ticker)	IRR	[1] Current Price	[2] Dividend EOY 1	[3] Dividend EOY 2	[4] Dividend EOY 3	[5] Dividend EOY 4	Dividend EOY 5	Dividend EOY 6	Dividend EOY 7	Dividend EOY 8	Dividend EOY 9	Dividend EOY 10
			[A]	[B]	[B]	[B]	[B]	[B]	[C]				
Alliant Energy	LNT	8.15%	($33.59)	$1.15	$1.25	$1.35	$1.45	$1.51	$1.58	$1.65	$1.72	$1.80	$1.88
Amer. Elec. Power	AEP	8.27%	($33.87)	$1.48	$1.60	$1.70	$1.80	$1.86	$1.93	$2.00	$2.07	$2.14	$2.21
Consol. Edison	ED	8.33%	($43.70)	$2.30	$2.32	$2.34	$2.36	$2.44	$2.52	$2.61	$2.70	$2.79	$2.89
Empire Dist. Elec.	EDE	9.09%	($20.49)	$1.28	$1.28	$1.28	$1.28	$1.32	$1.37	$1.41	$1.46	$1.51	$1.56
Energy East Corp.	EAS	9.27%	($23.70)	$1.18	$1.24	$1.29	$1.35	$1.40	$1.46	$1.53	$1.59	$1.66	$1.73
IDACORP, Inc.	IDA	7.87%	($33.68)	$1.20	$1.20	$1.20	$1.20	$1.26	$1.32	$1.38	$1.45	$1.52	$1.59
MGE Energy	MGEE	10.06%	($29.63)	$1.38	$1.39	$1.41	$1.42	$1.51	$1.60	$1.70	$1.80	$1.90	$2.02
NSTAR	NST	8.89%	($28.21)	$1.21	$1.26	$1.34	$1.42	$1.48	$1.55	$1.62	$1.69	$1.77	$1.85
OGE Energy	OGE	7.32%	($34.18)	$1.33	$1.36	$1.41	$1.45	$1.50	$1.56	$1.61	$1.67	$1.73	$1.79
Progress Energy	PGN	9.03%	($42.26)	$2.44	$2.50	$2.54	$2.58	$2.67	$2.76	$2.86	$2.96	$3.06	$3.17
Southern Co.	SO	9.60%	($31.80)	$1.54	$1.62	$1.71	$1.79	$1.88	$1.97	$2.06	$2.16	$2.26	$2.36
Wisconsin Energy	WEC	8.88%	($39.39)	$0.92	$0.96	$1.01	$1.05	$1.12	$1.20	$1.28	$1.37	$1.46	$1.56
WPS Resources	WPS	15.97%	($18.98)	$2.28	$2.32	$2.36	$2.40	$2.52	$2.64	$2.76	$2.90	$3.03	$3.18
Xcel Energy Inc.	XEL	9.61%	($18.98)	$0.88	$0.93	$0.99	$1.04	$1.09	$1.15	$1.20	$1.26	$1.32	$1.39
AGGREGATE		9.12%	($432.46)	$20.57	$21.23	$21.92	$22.60	$23.58	$24.60	$25.67	$26.79	$27.96	$29.18
Average		9.31%											
Stdev		1.98%											
Min		7.32%											
Max		15.97%											
Median		8.96%											
25 percentile		8.28%											
75 percentile		9.52%											

[A] Most current stock quotes provided by MSN Money, www.moneycentral.msn.com
[B] Value Line Data (See Schedule 3)
[C] Long-term growth is the input variable, based on consensus analyst growth expectations.

Value Line Data

Schedule 3

COHORT ELECTRIC COMPANIES UE 180

VALUE LINE'S EARNINGS PER SHARE PROJECTIONS

	2006	2007	2008	2009	2010
Alliant Energy	$2.30	$2.35	$2.38	$2.42	$2.45
Amer. Elec. Power	$2.70	$2.80	$2.95	$3.10	$3.25
Consol. Edison	$3.00	$3.05	$3.10	$3.15	$3.20
Empire Dist. Elec.	$1.05	$1.45	$1.47	$1.48	$1.50
Energy East Corp.	$1.60	$1.65	$1.77	$1.88	$2.00
IDACORP, Inc.	$1.85	$1.90	$1.93	$1.97	$2.00
MGE Energy	$1.80	$2.00	$2.15	$2.30	$2.45
NSTAR	$1.90	$2.05	$2.20	$2.35	$2.50
OGE Energy	$2.15	$2.10	$2.15	$2.20	$2.25
Progress Energy	$3.20	$3.30	$3.33	$3.37	$3.40
Southern Co.	$2.15	$2.25	$2.42	$2.58	$2.75
Wisconsin Energy	$2.55	$2.65	$2.85	$3.05	$3.25
WPS Resources	$3.75	$3.85	$3.92	$3.98	$4.05
Xcel Energy Inc.	$1.30	$1.40	$1.52	$1.63	$1.75
AVERAGE	**$2.24**	**$2.34**	**$2.44**	**$2.53**	**$2.63**

Note: Data are from the most current Value Line report(s)

Value Line's Dividends Per Share

COMPANY	2006	2007	2008	2009	2010	DPS growth
Alliant Energy	$1.15	$1.25	$1.35	$1.45	$1.55	**5.161%**
Amer. Elec. Power	$1.48	$1.60	$1.70	$1.80	$1.90	**4.421%**
Consol. Edison	$2.30	$2.32	$2.34	$2.36	$2.38	**0.672%**
Empire Dist. Elec.	$1.28	$1.28	$1.28	$1.28	$1.28	**0.000%**
Energy East Corp.	$1.18	$1.24	$1.29	$1.35	$1.40	**3.143%**
IDACORP, Inc.	$1.20	$1.20	$1.20	$1.20	$1.20	**0.000%**
MGE Energy	$1.38	$1.39	$1.41	$1.42	$1.44	**0.833%**
NSTAR	$1.21	$1.26	$1.34	$1.42	$1.50	**3.867%**
OGE Energy	$1.33	$1.36	$1.41	$1.45	$1.50	**2.267%**
Progress Energy	$2.44	$2.50	$2.54	$2.58	$2.62	**1.374%**
Southern Co.	$1.54	$1.62	$1.71	$1.79	$1.88	**3.617%**
Wisconsin Energy	$0.92	$0.96	$1.01	$1.05	$1.10	**3.273%**
WPS Resources	$2.28	$2.32	$2.36	$2.40	$2.44	**1.311%**
Xcel Energy Inc.	$0.88	$0.93	$0.99	$1.04	$1.10	**4.000%**
AVERAGE	**$1.47**	**$1.52**	**$1.57**	**$1.61**	**$1.66**	2.424%

Retention Rate

(Earnings less Dividends divided by Earnings)

2006	2007	2008	2009	2010
50.0%	46.8%	$0.43	$0.40	36.7%
45.2%	42.9%	$0.42	$0.42	41.5%
23.3%	23.9%	$0.25	$0.25	25.6%
-21.9%	11.7%	$0.13	$0.14	14.7%
26.3%	24.8%	$0.27	$0.28	30.0%
35.1%	36.8%	$0.38	$0.39	40.0%
23.3%	30.5%	$0.35	$0.38	41.2%
36.3%	38.5%	$0.39	$0.40	40.0%
38.1%	35.2%	$0.35	$0.34	33.3%
23.8%	24.2%	$0.24	$0.23	22.9%
28.4%	28.0%	$0.29	$0.31	31.6%
63.9%	63.8%	$0.65	$0.65	66.2%
39.2%	39.7%	$0.40	$0.40	39.8%
32.3%	33.6%	$0.35	$0.36	37.1%
31.7%	**34.3%**	**34.9%**	**35.4%**	**35.8%**

RETAINED EARNINGS

	2006	2007	2008	2009	2010
Alliant Energy	$1.15	$1.10	$1.03	$0.97	$0.90
Amer. Elec. Power	$1.22	$1.20	$1.25	$1.30	$1.35
Consol. Edison	$0.70	$0.73	$0.76	$0.79	$0.82
Empire Dist. Elec.	($0.23)	$0.17	$0.19	$0.20	$0.22
Energy East Corp.	$0.42	$0.41	$0.47	$0.54	$0.60
IDACORP, Inc.	$0.65	$0.70	$0.73	$0.77	$0.80
MGE Energy	$0.42	$0.61	$0.74	$0.88	$1.01
NSTAR	$0.69	$0.79	$0.86	$0.93	$1.00
OGE Energy	$0.82	$0.74	$0.74	$0.75	$0.75
Progress Energy	$0.76	$0.80	$0.79	$0.79	$0.78
Southern Co.	$0.61	$0.63	$0.71	$0.79	$0.87
Wisconsin Energy	$1.63	$1.69	$1.84	$2.00	$2.15
WPS Resources	$1.47	$1.53	$1.56	$1.58	$1.61
Xcel Energy Inc.	$0.42	$0.47	$0.53	$0.59	$0.65
AVERAGE	**$0.77**	**$0.83**	**$0.87**	**$0.92**	**$0.97**

VALUE LINE'S BOOK VALUE PER SHARE PROJECTIONS

	2005	2006	2007	2008	2009	2010
Alliant Energy	$22.13	$20.85	$22.10	$23.52	$24.93	$26.35
Amer. Elec. Power	$21.32	$23.08	$24.30	$26.03	$27.77	$29.50
Consol. Edison	$29.09	$29.80	$30.85	$32.00	$33.15	$34.30
Empire Dist. Elec.	$14.76	$15.08	$15.55	$15.95	$16.35	$16.75
Energy East Corp.	$17.89	$19.45	$19.25	$19.92	$20.58	$21.25
IDACORP, Inc.	$23.88	$24.04	$24.95	$26.05	$27.15	$28.25
MGE Energy	$16.59	$16.82	$17.10	$17.75	$18.40	$19.05
NSTAR	$13.52	$14.37	$15.05	$16.28	$17.52	$18.75
OGE Energy	$14.28	$15.19	$16.10	$17.23	$18.37	$19.50
Progress Energy	$30.90	$31.90	$32.80	$34.08	$35.37	$36.65
Southern Co.	$13.86	$14.41	$15.05	$16.23	$17.42	$18.60
Wisconsin Energy	$21.31	$22.91	$24.20	$26.22	$28.23	$30.25
WPS Resources	$29.30	$32.47	$35.15	$37.38	$39.62	$41.85
Xcel Energy Inc.	$12.99	$13.37	$13.95	$14.55	$15.15	$15.75
AVERAGE	**$20.13**	**$20.98**	**$21.89**	**$23.09**	**$24.29**	**$25.49**

SELECTED COMPANIES 40-YEAR MULTISTAGE DCF METHOD — UE 180 — Schedule 4 - 40-year 3-stage DCF Model

Page 1

RESULTING IRR 9.47%

Based on the Recent Price reported in Value Line

	Year	[1] Year End Book	[2] Retention Rate	[3] Dividend	[4] Earnings Per Share	[5] Retained Earnings Per Share	[6] Total Increment to Book	[7] Market Price	[8] Mkt to Book	[9] Expect. Ret. on Equity	[10] Cash Fl. from Stock Trans.	[11] Cash Fl. from Div.	[12] Total Cash Flow	
		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	
First Stage	2005	$20.13						$33.79	1.73		($33.79)		($33.79)	First Stage
	2006	$20.98	34.28%	$1.47	$2.24			$36.38	1.73	10.88%		$1.47	$1.47	
	2007	$21.89	35.27%	$1.52	$2.34			$37.95	1.73	10.93%		$1.52	$1.52	
	2008	$23.09	35.79%	$1.57	$2.44			$40.03	1.73	10.84%		$1.57	$1.57	
	2009	$24.29	36.27%	$1.61	$2.53			$42.11	1.73	10.70%		$1.61	$1.61	
	2010	$25.49	36.71%	$1.66	$2.63			$44.19	1.73	10.56%		$1.66	$1.66	
Second Stage	2011	$26.77	40.00%	$1.93	$3.21	$1.28	$1.28	$46.42	1.73	12.00%		$1.93	$1.93	Second Stage
	2012	$28.12	40.00%	$2.02	$3.37	$1.35	$1.35	$48.76	1.73	12.00%		$2.02	$2.02	
	2013	$29.54	40.00%	$2.13	$3.54	$1.42	$1.42	$51.22	1.73	12.00%		$2.13	$2.13	
	2014	$31.03	40.00%	$2.23	$3.72	$1.49	$1.49	$53.80	1.73	12.00%		$2.23	$2.23	
	2015	$32.59	40.00%	$2.35	$3.91	$1.56	$1.56	$56.51	1.73	12.00%		$2.35	$2.35	
	2016	$34.24	40.00%	$2.46	$4.11	$1.64	$1.64	$59.36	1.73	12.00%		$2.46	$2.46	
	2017	$35.96	40.00%	$2.59	$4.32	$1.73	$1.73	$62.35	1.73	12.00%		$2.59	$2.59	
	2018	$37.77	40.00%	$2.72	$4.53	$1.81	$1.81	$65.50	1.73	12.00%		$2.72	$2.72	
	2019	$39.68	40.00%	$2.86	$4.76	$1.90	$1.90	$68.80	1.73	12.00%		$2.86	$2.86	
	2020	$41.68	40.00%	$3.00	$5.00	$2.00	$2.00	$72.27	1.73	12.00%		$3.00	$3.00	
	2021	$43.78	40.00%	$3.15	$5.25	$2.10	$2.10	$75.91	1.73	12.00%		$3.15	$3.15	
	2022	$45.99	40.00%	$3.31	$5.52	$2.21	$2.21	$79.74	1.73	12.00%		$3.31	$3.31	
	2023	$48.31	40.00%	$3.48	$5.80	$2.32	$2.32	$83.76	1.73	12.00%		$3.48	$3.48	
	2024	$50.74	40.00%	$3.65	$6.09	$2.44	$2.44	$87.99	1.73	12.00%		$3.65	$3.65	
	2025	$53.30	40.00%	$3.84	$6.40	$2.56	$2.56	$92.42	1.73	12.00%		$3.84	$3.84	
	2026	$55.99	40.00%	$4.03	$6.72	$2.69	$2.69	$97.08	1.73	12.00%		$4.03	$4.03	
	2027	$58.81	40.00%	$4.23	$7.06	$2.82	$2.82	$101.98	1.73	12.00%		$4.23	$4.23	
	2028	$61.78	40.00%	$4.45	$7.41	$2.97	$2.97	$107.12	1.73	12.00%		$4.45	$4.45	
	2029	$64.89	40.00%	$4.67	$7.79	$3.11	$3.11	$112.52	1.73	12.00%		$4.67	$4.67	
	2030	$68.16	40.00%	$4.91	$8.18	$3.27	$3.27	$118.19	1.73	12.00%		$4.91	$4.91	
	2031	$71.60	40.00%	$5.16	$8.59	$3.44	$3.44	$124.15	1.73	12.00%		$5.16	$5.16	
	2032	$75.21	40.00%	$5.42	$9.03	$3.61	$3.61	$130.41	1.73	12.00%		$5.42	$5.42	
	2033	$79.00	40.00%	$5.69	$9.48	$3.79	$3.79	$136.99	1.73	12.00%		$5.69	$5.69	
	2034	$82.99	40.00%	$5.98	$9.96	$3.98	$3.98	$143.89	1.73	12.00%		$5.98	$5.98	
	2035	$87.17	40.00%	$6.28	$10.46	$4.18	$4.18	$151.15	1.73	12.00%		$6.28	$6.28	
	2036	$91.57	40.00%	$6.59	$10.99	$4.40	$4.40	$158.77	1.73	12.00%		$6.59	$6.59	
	2037	$96.18	40.00%	$6.93	$11.54	$4.62	$4.62	$166.77	1.73	12.00%		$6.93	$6.93	
	2038	$101.03	40.00%	$7.27	$12.12	$4.85	$4.85	$175.18	1.73	12.00%		$7.27	$7.27	
	2039	$106.13	40.00%	$7.64	$12.74	$5.09	$5.09	$184.02	1.73	12.00%		$7.64	$7.64	
	2040	$111.48	40.00%	$8.03	$13.38	$5.35	$5.35	$193.29	1.73	12.00%		$8.03	$8.03	
	2041	$117.10	40.00%	$8.43	$14.05	$5.62	$5.62	$203.04	1.73	12.00%		$8.43	$8.43	
	2042	$123.00	40.00%	$8.86	$14.76	$5.90	$5.90	$213.28	1.73	12.00%		$8.86	$8.86	
	2043	$129.20	40.00%	$9.30	$15.50	$6.20	$6.20	$224.03	1.73	12.00%		$9.30	$9.30	
	2044	$135.72	40.00%	$9.77	$16.29	$6.51	$6.51	$235.33	1.73	12.00%		$9.77	$9.77	
3rd Stage	2045	$142.56	40.00%	$10.26	$17.11	$6.84	$6.84	$247.19	1.73	12.00%	$247.19	$10.26	$257.46	3rd Stage

Long-run Retention Rate
40.00%
ROE
12.00%
GROWTH
4.80%

Internal Rate of Return **9.47%**

Source:

[A] First Stage is average from Value Line. Second stage is prior years' book value plus value from Col. [6]
[B] First Stage is (Col. [4]-Col.[3]/Col.[4]). First year of second stage computed by 1-dividends/earnings; subsequent years use the same retention rate.
[C] First Stage is from Value Line. First year of second stage determined by Terminal Retention rate and ROE.
Subsequent years of second stage is Col. [4] x (1-Col. [2])
[D] First Stage is from Value line. Second stage is average of current and prior year's value from Col. [1] x Col. [9]
[E] Col. [4] - Col. [3]
[F] Col. [4] - Col. [3]
[G] Col. [1] x Col. [10]
[H] Staff/1002 Morgan/10 (Schedule 7)
[I] First stage is Col. [4]/Ave. of Current and prior year's Col. [1]. Second stage is input.
[J] Input is "negative" Col. [7] for year of purchase, "positive" Col. [7] for year of sale.
[K] Col. [3]
[L] Col. [10] + Col. [11]

SELECTED COMPANIES 40-YEAR MULTISTAGE DCF METHOD

SENSITIVITY ANALYSES, EXPECTED INTERNAL RATE OF RETURN

Terminal Retention Rate	Terminal ROE								
	10.00%	**10.50%**	**11.00%**	**11.50%**	**12.00%**	**12.50%**	**13.00%**	**13.50%**	**14.00%**
30.00%	7.81%	8.10%	8.40%	8.69%	8.98%	9.27%	9.56%	9.84%	10.13%
35.00%	7.99%	8.30%	8.61%	8.92%	9.22%	9.52%	9.83%	10.13%	10.42%
40.00%	8.18%	8.50%	8.83%	9.15%	9.47%	9.79%	10.10%	10.42%	10.73%
45.00%	8.37%	8.71%	9.05%	9.39%	9.72%	10.05%	10.39%	10.72%	11.05%
50.00%	8.58%	8.93%	9.28%	9.63%	9.98%	10.33%	10.68%	11.03%	11.38%

SENSITIVITY ANALYSES, EXPECTED ORGANIC GROWTH RATE

Terminal Retention Rate	Terminal ROE								
	10.00%	**10.50%**	**11.00%**	**11.50%**	**12.00%**	**12.50%**	**13.00%**	**13.50%**	**14.00%**
30.00%	3.00%	3.15%	3.30%	3.45%	3.60%	3.75%	3.90%	4.05%	4.20%
35.00%	3.50%	3.68%	3.85%	4.03%	4.20%	4.38%	4.55%	4.73%	4.90%
40.00%	4.00%	4.20%	4.40%	4.60%	4.80%	5.00%	5.20%	5.40%	5.60%
45.00%	4.50%	4.73%	4.95%	5.18%	5.40%	5.63%	5.85%	6.08%	6.30%
50.00%	5.00%	5.25%	5.50%	5.75%	6.00%	6.25%	6.50%	6.75%	7.00%

Terminal Retention Rate	IRR
25.00%	8.76%
30.00%	8.98%
35.00%	9.22%
40.00%	9.47%
45.00%	9.72%

Terminal ROE	COE
9.50%	7.85%
10.00%	8.18%
10.50%	8.50%
11.00%	8.83%
11.50%	9.15%
12.00%	9.47%

M/B Ratio	IRR
1.250	9.15%
1.375	9.24%
1.500	9.32%
1.625	9.40%
1.750	9.48%

Stock Prices Used in DCF Models Data from: 08/08/2006 **Schedule 5**

UE 180

Stock Quotes Provided by MSN Money

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			Last	Previous Close	High	Low	Volume	Change	% Change	52 Wk High	52 Wk Low	Market Cap	EPS	P/E Ratio	# Shares Out
Alliant Energy Corporation	Chart	News	36.35	36.3	36.49	36.33	123,300	0.05	0.14%	36.98	25.79	4,280,506,755	0.79	43.7	117,758,100
American Electric Power Company.	Chart	News	36.63	36.52	36.72	36.55	432,400	0.11	0.30%	40.8	32.27	14,431,308,334	2.02	14.3	393,975,100
Consolidated Edison, Inc.	Chart	News	46.06	46.01	46.23	45.96	500,900	0.05	0.11%	49.29	41.17	11,352,251,934	2.97	15.3	246,466,600
The Empire District Electric Company	Chart	News	22.18	21.8	22.24	21.97	48,500	0.38	1.74%	24.16	19.25	580,826,559	0.99	22.1	26,186,950
Energy East Corporation	Chart	News	24.91	24.89	24.99	24.86	208,000	0.02	0.08%	26.69	22.18	3,679,244,342	1.67	14.9	147,701,500
IDACORP, Inc.	Chart	News	36.82	36.82	36.99	36.27	331,500	unch	0.00%	37.49	27.46	1,575,631,251	1.56	23.6	42,792,810
MGE Energy, Inc.	Chart	News	31.98	31.02	31.98	31.2	18,251	0.96	3.09%	38.12	29.2	654,134,901	1.73	17.9	20,454,500
NSTAR	Chart	News	31.83	31.83	31.95	31.55	257,700	unch	0.00%	32.05	24.9	3,399,711,364	1.92	16.5	106,808,400
OGE Energy Corp.	Chart	News	35.79	35.57	35.96	35.64	194,800	0.22	0.62%	39.15	24.41	3,255,894,048	3.13	15.7	90,972,170
Progress Energy, Inc.	Chart	News	43.88	43.63	43.99	43.7	344,700	0.25	0.57%	45.5	40.19	11,100,337,034	2.62	16.2	252,970,300
The Southern Company	Chart	News	33.55	33.47	33.81	33.5	539,100	0.08	0.24%	36.47	30.48	24,903,698,089	2.06	16.2	742,286,100
Wisconsin Energy Corporation	Chart	News	41.67	41.55	41.72	41.51	73,500	0.12	0.29%	43	36.49	4,874,510,549	2.75	15.3	116,978,900
WPS Resources Corp	Chart	News	51.37	51	51.43	50.92	76,800	0.37	0.73%	59.65	47.39	2,215,478,636	4.05	12.2	43,127,870
Xcel Energy Inc.	Chart	News	20.57	20.41	20.6	20.46	234,400	0.16	0.78%	20.64	17.8	8,350,749,294	1.34	15.6	405,967,400

COMPARATIVE ELECTRIC COMPANIES **Docket UE 180**

Schedule 6 - Capital Structure Analysis

Percentage of Common Equity in the Capital Structure
Excluding Short-term Debt

COMPANIES	Ticker	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006 Est.	2007	'09 - '11	Ave. '96-'06	Ave. '96-'10	Ave. '99-'10
Alliant Energy	LNT			49.2%	57.4%	50.2%	42.7%	39.2%	50.0%	50.2%	53.1%	57.5%	55.5%	50.5%	49.9%	50.5%	50.6%
Amer. Elec. Power	AEP					44.4%	44.6%	43.1%	38.7%	43.1%	44.9%	41.5%	40.0%	40.5%	42.9%	42.3%	42.3%
Consol. Edison	ED	55.7%	56.8%	58.4%	53.1%	49.1%	49.6%	48.1%	48.0%	51.0%	49.0%	50.0%	50.0%	50.5%	51.7%	51.5%	49.8%
Empire Dist. Elec.	EDE	45.8%	48.9%	45.2%	40.4%	42.4%	42.8%	44.5%	48.0%	48.7%	49.0%	49.0%	48.0%	48.5%	45.9%	46.2%	46.1%
Energy East Corp.	EAS	51.9%	52.8%	53.5%	53.0%	41.8%	38.4%	39.2%	38.5%	40.6%	43.8%	43.5%	43.0%	45.0%	45.2%	45.0%	42.7%
IDACORP, Inc.	IDA	45.1%	46.8%	44.2%	44.8%	45.9%	47.9%	47.9%	46.4%	50.7%	50.0%	50.5%	50.0%	50.5%	47.3%	47.7%	48.5%
MGE Energy	MGEE	58.1%	58.2%	53.3%	55.5%	52.2%	57.8%	54.2%	56.5%	62.6%	60.7%	60.5%	60.5%	61.0%	57.2%	57.8%	58.2%
NSTAR	NST	44.5%	46.5%	50.1%	47.2%	39.4%	39.5%	37.8%	40.2%	40.2%	38.6%	39.0%	42.0%	51.5%	42.1%	42.8%	41.5%
OGE Energy	OGE	52.3%	52.5%	52.7%	47.2%	39.2%	40.5%	39.6%	45.6%	47.4%	50.5%	48.5%	50.0%	54.0%	46.9%	47.7%	46.3%
Progress Energy	PGN	50.2%	53.2%	52.4%	52.5%	47.6%	38.5%	40.4%	43.4%	44.3%	43.3%	46.0%	48.5%	51.0%	46.5%	47.0%	45.6%
Southern Co.	SO	49.7%	43.5%	42.9%	37.8%	50.6%	42.2%	43.4%	43.6%	44.1%	44.3%	44.5%	44.5%	46.0%	44.2%	44.4%	44.1%
Wisconsin Energy	WEC	57.4%	54.4%	51.7%	45.9%	40.5%	37.2%	39.6%	39.6%	43.3%	46.7%	44.0%	47.0%	48.5%	45.5%	45.8%	43.2%
WPS Resources	WPS	56.7%	57.4%	53.8%	43.9%	41.6%	46.3%	45.8%	52.1%	54.4%	58.7%	57.0%	54.5%	52.0%	51.6%	51.9%	50.6%
Xcel Energy Inc.	XEL						32.8%	39.5%	43.8%	44.1%	47.3%	46.0%	49.5%	52.5%	42.3%	44.4%	44.4%
Average		51.6%	51.9%	50.6%	48.2%	45.0%	42.9%	43.0%	45.3%	47.5%	48.6%	48.4%	48.8%	50.1%	47.1%	47.5%	46.7%
Standard Deviation		5.0%	4.9%	4.5%	6.1%	4.6%	6.2%	4.7%	5.3%	6.1%	6.0%	6.3%	5.5%	4.7%	4.3%	4.2%	4.5%
25th Percentile		47.8%	47.9%	48.2%	44.6%	41.6%	38.8%	39.5%	41.0%	43.5%	44.5%	44.1%	45.1%	48.5%	44.5%	44.6%	43.4%
Median		51.9%	52.8%	52.1%	47.2%	44.4%	42.5%	41.8%	44.7%	45.9%	48.2%	47.3%	49.0%	50.5%	46.2%	46.6%	45.8%
75th Percentile		56.2%	55.6%	53.4%	53.0%	49.1%	45.9%	45.5%	48.0%	50.6%	50.4%	50.4%	50.0%	51.9%	49.3%	49.8%	49.5%
Minimum		44.5%	43.5%	42.9%	37.8%	39.2%	32.8%	37.8%	38.5%	40.2%	38.6%	39.0%	40.0%	40.5%	42.1%	42.3%	41.5%
Maximum		58.1%	58.2%	58.4%	57.4%	52.2%	57.8%	54.2%	56.5%	62.6%	60.7%	60.5%	60.5%	61.0%	57.2%	57.8%	58.2%

Source: Value Line ***Most current through: Sep-06***

Schedule 7

	Line	Symbol	DivYld	Wt'ed M/B M/B	EOY 2005 M/B
Alliant Energy	1	LNT	3.25%	1.68	1.74
Amer. Elec. Power	2	AEP	4.20%	1.53	1.59
Consol. Edison	3	ED	5.02%	1.51	1.55
Empire Dist. Elec.	4	EDE	5.77%	1.44	1.47
Energy East Corp.	5	EAS	4.86%	1.29	1.28
IDACORP, Inc.	6	IDA	3.26%	1.49	1.53
MGE Energy	7	MGEE	4.32%	1.88	1.90
NSTAR	8	NST	3.90%	2.15	2.22
OGE Energy	9	OGE	3.77%	2.27	2.36
Progress Energy	10	PGN	5.61%	1.35	1.38
Southern Co.	11	SO	4.65%	2.26	2.33
Wisconsin Energy	12	WEC	2.26%	1.75	1.82
WPS Resources	13	WPS	4.48%	1.50	1.58
Xcel Energy Inc.	14	XEL	4.33%	1.50	1.54
			DivYld	M/B	M/B
Average			4.26%	1.69	1.73

Schedule 7

OUTSTANDING SHARES (millions)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	'09-'11
Alliant Energy									77.63	78.98	79.01	89.68	92.30	110.96	115.74	117.04	118.10	119.10	122.10
Amer. Elec. Power											322.02	322.24	338.84	395.02	395.86	393.72	394.00	396.00	400.00
Consol. Edison	228.23	228.33	233.93	234.37	234.91	234.96	234.99	235.49	232.83	213.81	212.03	212.15	213.93	225.84	242.51	245.29	255.00	257.00	263.00
Empire Dist. Elec.	12.67	12.99	13.29	13.57	13.94	15.22	16.44	16.78	17.11	17.37	17.60	19.76	22.57	24.98	25.70	26.08	30.15	31.20	33.00
Energy East Corp.	124.86	126.80	138.88	141.19	143.01	143.01	139.34	135.02	125.89	109.34	117.66	116.72	144.97	146.26	147.12	147.70	148.00	148.25	149.00
IDACORP, Inc.	33.98	33.98	36.19	37.09	37.61	37.61	37.61	37.61	37.61	37.61	37.61	37.63	38.02	38.34	42.22	42.66	43.90	45.20	46.10
MGE Energy	16.02	16.05	16.05	16.08	16.08	16.08	16.08	16.08	16.08	16.16	16.62	17.07	17.57	18.34	20.39	20.45	20.50	20.50	20.50
NSTAR	78.00	84.09	89.53	90.26	91.07	96.01	97.02	97.03	94.37	116.12	106.07	106.07	106.07	106.07	106.55	106.81	106.81	106.81	106.81
OGE Energy	80.60	80.60	80.66	80.69	80.71	80.75	80.76	80.77	80.80	77.86	77.92	77.99	78.50	87.40	90.00	90.60	91.20	91.80	93.50
Progress Energy												218.73	232.43	246.00	247.00	252.00	254.00	256.00	261.00
Southern Co.					657.00	670.00	677.00	685.00	698.63	666.00	682.00	699.00	716.90	734.80	741.80	741.60	750.00	755.00	780.00
Wisconsin Energy	101.04	101.04	103.09	105.32	108.94	110.82	111.68	112.87	115.61	118.90	118.65	115.42	116.03	118.43	116.99	116.98	117.00	117.00	117.00
WPS Resources	22.89	22.89	23.85	23.90	23.90	23.90	23.90	23.90	26.55	26.85	26.85	31.18	32.01	36.91	37.26	40.16	43.30	43.80	45.30
Xcel Energy Inc.												345.02	398.71	398.96	400.46	403.39	406.00	427.00	435.00

Average

Schedule 7

Alliant Energy
Amer. Elec. Power
Consol. Edison
Empire Dist. Elec.
Energy East Corp.
IDACORP, Inc.
MGE Energy
NSTAR
OGE Energy
Progress Energy
Southern Co.
Wisconsin Energy
WPS Resources
Xcel Energy Inc.

Average

Schedule 7

BOOK VALUE PER SHARE

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	'09-'11
Alliant Energy									20.69	27.29	25.79	21.39	19.89	21.37	22.13	20.85	22.10	13.30	26.35
Amer. Elec. Power											25.01	25.54	20.85	19.93	21.32	23.08	24.30	25.60	29.50
Consol. Edison	19.73	20.18	20.89	21.63	22.62	23.51	24.37	25.18	25.88	25.31	25.81	26.71	27.68	28.44	29.09	29.80	30.85	31.70	34.30
Empire Dist. Elec.	11.75	12.08	12.29	12.37	12.47	12.69	12.96	13.06	13.43	13.48	13.65	13.58	14.59	15.17	14.76	15.08	15.55	15.95	16.75
Energy East Corp.	10.93	11.08	11.42	11.44	11.64	12.19	12.70	13.36	13.61	12.84	14.59	15.26	16.97	17.59	17.89	19.45	19.25	19.65	21.25
IDACORP, Inc.	17.40	17.06	17.28	17.86	17.91	18.15	18.47	18.93	19.42	20.02	21.82	23.15	23.01	22.54	23.88	24.04	24.95	25.90	28.25
MGE Energy	10.62	10.98	11.24	11.51	11.78	12.01	11.14	11.25	11.34	11.49	12.05	12.67	12.94	14.34	16.59	16.82	17.10	17.55	19.05
NSTAR	8.61	8.96	9.39	9.71	10.06	10.31	10.54	10.98	11.14	13.29	12.65	11.90	12.25	12.84	13.52	14.37	15.05	15.90	18.75
OGE Energy	10.96	11.30	11.18	11.24	11.41	11.61	11.91	12.19	12.91	13.09	13.66	13.34	12.53	13.75	14.28	15.19	16.10	16.95	19.50
Progress Energy												27.45	28.73	30.26	30.90	31.90	32.80	33.75	36.65
Southern Co.					12.46	13.09	13.61	14.08	14.02	13.82	15.67	11.42	12.15	13.13	13.86	14.41	15.05	15.80	18.60
Wisconsin Energy	13.70	14.35	14.97	15.67	16.01	16.89	17.42	16.51	16.46	16.89	17.00	17.81	18.44	19.92	21.31	22.91	24.20	25.60	30.25
WPS Resources	16.26	16.13	17.33	18.18	18.69	19.39	19.56	20.00	19.48	19.97	20.21	22.96	24.45	27.18	29.30	32.47	35.15	36.85	41.85
Xcel Energy Inc.												17.95	11.70	12.95	12.99	13.37	13.95	14.35	15.75
Average																			

Schedule 7

Alliant Energy
Amer. Elec. Power
Consol. Edison
Empire Dist. Elec.
Energy East Corp.
IDACORP, Inc.
MGE Energy
NSTAR
OGE Energy
Progress Energy
Southern Co.
Wisconsin Energy
WPS Resources
Xcel Energy Inc.

Average

Schedule 7

DIVIDENDS DECLARED PER SHARE

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	'09-'11
Alliant Energy									2.00	2.00	2.00	2.00	2.00	1.00	1.02	1.05	1.15	1.25	1.55
Amer. Elec. Power											2.40	2.40	2.40	1.65	1.40	1.42	1.48	1.60	1.90
Consol. Edison	1.82	1.86	1.90	1.94	2.00	2.04	2.08	2.10	2.12	2.14	2.18	2.20	2.22	2.24	2.26	2.28	2.30	2.32	2.38
Empire Dist. Elec.	1.18	1.22	1.26	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28
Energy East Corp.	1.03	1.05	1.07	1.09	1.00	0.70	0.70	0.70	0.78	0.84	0.88	0.92	0.96	1.00	1.06	1.12	1.18	1.24	1.40
IDACORP, Inc.	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.70	1.20	1.20	1.20	1.20	1.20
MGE Energy	1.15	1.17	1.19	1.19	1.25	1.26	1.28	1.29	1.30	1.31	1.32	1.33	1.34	1.35	1.36	1.37	1.38	1.39	1.44
NSTAR	0.77	0.80	0.83	0.86	0.89	0.92	0.94	0.94	0.95	0.98	1.01	1.04	1.07	1.09	1.13	0.87	1.21	1.26	1.50
OGE Energy	1.26	1.30	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.36	1.50
Progress Energy												2.14	2.18	2.26	2.32	2.38	2.44	2.50	2.62
Southern Co.							1.26	1.30	1.34	1.34	1.34	1.34	1.36	1.39	1.42	1.48	1.54	1.62	1.88
Wisconsin Energy	1.16	1.23	1.29	1.34	1.40	1.46	1.51	1.54	1.56	1.56	1.37	0.80	0.80	0.80	0.83	0.88	0.92	0.96	1.10
WPS Resources	1.64	1.68	1.72	1.76	1.80	1.84	1.88	1.92	1.96	2.00	2.04	2.08	2.12	2.16	2.20	2.24	2.28	2.32	2.44
Xcel Energy Inc.												1.50	1.13	0.75	0.81	0.85	0.88	0.93	1.10

Average

Schedule 7

Alliant Energy	Alliant Energy	LNT
Amer. Elec. Power	Amer. Elec. Powe	AEP
Consol. Edison	Consol. Edison	ED
Empire Dist. Elec.	Empire Dist. Elec.	EDE
Energy East Corp.	Energy East Corp	EAS
IDACORP, Inc.	IDACORP, Inc.	IDA
MGE Energy	MGE Energy	MGEE
NSTAR	NSTAR	NST
OGE Energy	OGE Energy	OGE
Progress Energy	Progress Energy	PGN
Southern Co.	Southern Co.	SO
Wisconsin Energy	Wisconsin Energy	WEC
WPS Resources	WPS Resources	WPS
Xcel Energy Inc.	Xcel Energy Inc.	XEL
Average		

Schedule 7

EARNINGS PER SHARE

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	'09-'11
Alliant Energy									1.26	2.19	2.47	2.42	1.18	1.57	1.85	2.21	2.30	2.35	2.45
Amer. Elec. Power											1.04	3.27	2.86	2.53	2.61	2.64	2.70	2.80	3.25
Consol. Edison	2.34	2.32	2.46	2.66	2.98	2.93	2.93	2.95	3.04	3.13	2.74	3.21	3.13	2.83	2.32	2.99	3.00	3.05	3.20
Empire Dist. Elec.	1.28	1.43	1.26	1.16	1.32	1.18	1.23	1.29	1.53	1.13	1.35	0.59	1.19	1.29	0.86	0.92	1.05	1.45	1.50
Energy East Corp.	1.24	1.18	1.20	1.04	1.19	1.25	1.26	1.29	1.51	1.91	2.07	2.00	1.50	1.43	1.62	1.74	1.60	1.65	2.00
IDACORP, Inc.	1.91	1.56	1.55	1.97	1.80	2.10	2.21	2.32	2.37	2.43	3.50	3.35	1.63	0.96	1.90	1.75	1.85	1.90	2.00
MGE Energy	1.36	1.52	1.45	1.51	1.53	1.49	0.82	1.40	1.38	1.48	1.67	1.62	1.69	1.71	1.77	1.57	1.80	2.00	2.45
NSTAR	0.80	0.98	1.05	1.14	1.21	1.04	1.31	1.36	1.38	1.39	1.60	1.64	1.69	1.74	1.76	1.83	1.90	2.05	2.50
OGE Energy	1.69	1.64	1.21	1.39	1.51	1.52	1.62	1.61	2.04	1.94	1.89	1.29	1.43	1.73	1.78	1.83	2.15	2.10	2.25
Progress Energy												3.43	3.84	3.41	3.10	2.94	3.20	3.30	3.40
Southern Co.					1.52	1.66	1.68	1.58	1.73	1.83	2.01	1.61	1.85	1.97	2.06	2.13	2.15	2.25	2.75
Wisconsin Energy	1.85	1.87	1.67	1.81	1.67	2.13	1.97	0.54	1.65	1.88	1.08	1.84	2.32	2.26	1.85	2.56	2.55	2.65	3.25
WPS Resources	2.00	2.23	2.35	2.47	2.21	2.32	2.00	2.13	1.76	2.24	2.43	2.74	2.74	2.76	4.07	4.09	3.75	3.85	4.05
Xcel Energy Inc.												2.27	0.42	1.23	1.27	1.20	1.30	1.40	1.75

Average

Schedule 7

VALUE LINE'S REPORTED RETURN ON EQUITY (ROE)

	Symbol	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	'09-'11
Alliant Energy	LNT			6.0%	8.0%	9.6%	9.8%	5.8%	6.7%	8.2%	13.1%	10.5%	10.0%	9.5%
Amer. Elec. Power	AEP						12.8%	13.7%	12.4%	12.2%	11.3%	11.0%	11.0%	11.0%
Consol. Edison	ED	11.7%	11.7%	11.8%	12.9%	10.7%	12.0%	11.3%	9.8%	7.8%	9.7%	9.5%	9.5%	9.5%
Empire Dist. Elec.	EDE	9.2%	9.8%	11.3%	8.8%	9.8%	3.9%	7.8%	7.8%	5.8%	6.0%	6.0%	9.0%	9.5%
Energy East Corp.	EAS	10.1%	9.7%	11.3%	15.8%	13.8%	13.1%	8.0%	8.1%	9.0%	8.9%	8.5%	8.5%	9.5%
IDACORP, Inc.	IDA	11.9%	12.2%	12.2%	12.1%	16.0%	14.4%	7.0%	4.2%	7.2%	6.2%	7.5%	7.0%	7.0%
MGE Energy	MGEE	7.4%	12.4%	12.2%	12.8%	13.7%	12.6%	12.8%	11.6%	10.0%	9.3%	10.5%	11.5%	12.0%
NSTAR	NST	12.3%	12.3%	12.6%	9.1%	13.0%	13.7%	13.8%	13.7%	13.1%	12.8%	12.5%	13.0%	13.5%
OGE Energy	OGE	13.6%	13.2%	15.8%	14.8%	13.8%	9.7%	11.4%	11.8%	12.3%	12.1%	11.5%	12.5%	12.0%
Progress Energy	PGN						11.5%	12.1%	10.9%	9.9%	9.0%	9.5%	9.5%	9.0%
Southern Co.	SO	12.2%	11.2%	12.2%	13.6%	12.3%	14.0%	15.1%	14.8%	14.9%	14.9%	14.0%	14.0%	14.5%
Wisconsin Energy	WEC	11.2%	3.3%	9.9%	10.9%	6.5%	10.6%	12.6%	11.4%	8.8%	11.3%	10.5%	10.5%	11.0%
WPS Resources	WPS	10.1%	10.6%	9.0%	11.1%	11.9%	10.8%	11.7%	9.1%	14.0%	11.8%	10.5%	10.5%	9.5%
Xcel Energy Inc.	XEL						12.6%	3.7%	9.8%	10.0%	9.2%	10.0%	9.5%	10.5%

Average

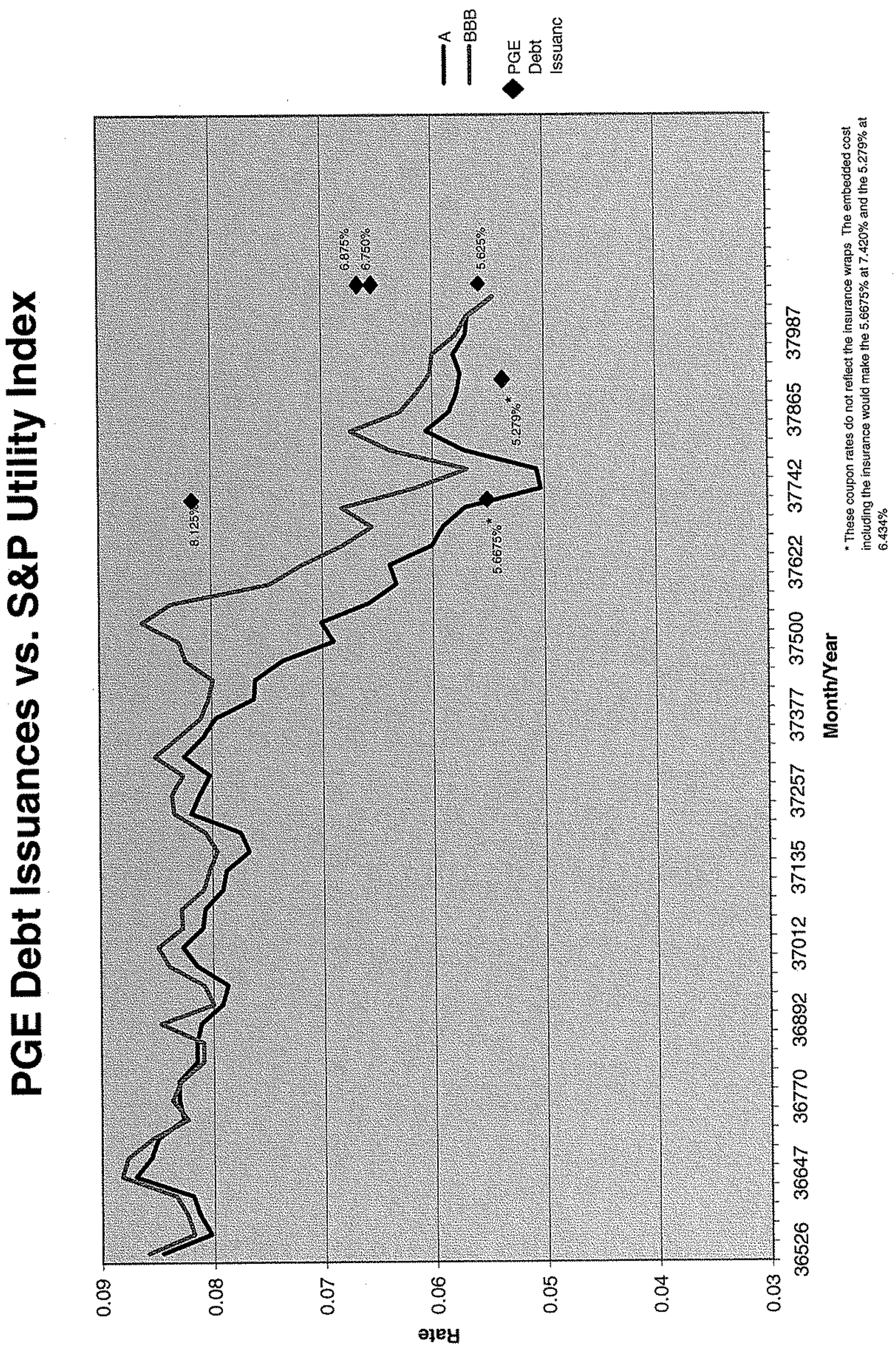
Analyst Earnings Growth Expectations
UE 180

Schedule 8

Electric Companies		Kiplinger's		Firstcall		Zack's	Reuters	Value Line	Average	Median	Minimum	Maximum
		Last 5 years	Next 5 years	Last 5 years	Next 5 years	Next 5 years	Next 5 years	Next 5 years				
Alliant Energy	LNT	N/A	5.00%	2.80%	2.50%	4.00%	4.00%	6.50%	4.40%	4.00%	2.50%	6.50%
Amer. Elec. Power	AEP	N/A	3.00%	-6.40%	3.00%	6.00%	3.57%	2.00%	3.51%	3.00%	2.00%	6.00%
Consol. Edison	ED	-3.00%	4.00%	-3.00%	4.00%	3.90%	3.67%	1.50%	3.41%	3.90%	1.50%	4.00%
Empire Dist. Elec.	EDE	-1.00%	3.00%	2.60%	3.00%	N/A	2.50%	5.00%	3.38%	3.00%	2.50%	5.00%
Energy East Corp.	EAS	-3.00%	4.00%	-3.10%	4.00%	4.50%	4.33%	4.50%	4.27%	4.33%	4.00%	4.50%
IDACORP, Inc.	IDA	-17.00%	5.00%	-7.40%	5.00%	4.70%	4.75%	4.50%	4.79%	4.75%	4.50%	5.00%
MGE Energy	MGEE	0.00%	N/A	N/A	N/A	N/A	N/A	6.00%	6.00%	6.00%	6.00%	6.00%
NSTAR	NST	N/A	5.00%	2.30%	5.00%	5.00%	5.00%	2.50%	4.50%	5.00%	2.50%	5.00%
OGE Energy	OGE	10.00%	3.00%	7.40%	3.00%	3.00%	3.00%	5.50%	3.50%	3.00%	3.00%	5.50%
Progress Energy	PGN	0.00%	4.00%	-2.90%	3.50%	3.60%	2.87%	N/A	3.49%	3.55%	2.87%	4.00%
Southern Co.	SO	2.00%	5.00%	6.40%	5.00%	4.80%	4.70%	4.00%	4.70%	4.80%	4.00%	5.00%
Wisconsin Energy	WEC	13.00%	8.00%	6.10%	8.00%	7.00%	7.00%	4.00%	6.80%	7.00%	4.00%	8.00%
WPS Resources	WPS	10.00%	5.00%	12.10%	5.00%	4.50%	4.50%	5.00%	4.80%	5.00%	4.50%	5.00%
Xcel Energy Inc.	XEL	N/A	4.00%	-14.30%	4.00%	4.50%	4.29%	7.50%	4.86%	4.29%	4.00%	7.50%
AVERAGE		**1.10%**	**4.46%**	**0.20%**	**4.23%**	**4.63%**	**4.17%**	**4.50%**	**4.46%**	**4.40%**	**3.42%**	**5.50%**
MEDIAN		**0.00%**	**4.00%**	**2.30%**	**4.00%**	**4.50%**	**4.29%**	**4.50%**	**4.45%**	**4.31%**	**3.50%**	**5.00%**
MIN		**-17.00%**	**3.00%**	**-14.30%**	**2.50%**	**3.00%**	**2.50%**	**1.50%**	**3.38%**	**3.00%**	**1.50%**	**4.00%**
MAX		**13.00%**	**8.00%**	**12.10%**	**8.00%**	**7.00%**	**7.00%**	**7.50%**	**6.80%**	**7.00%**	**6.00%**	**8.00%**

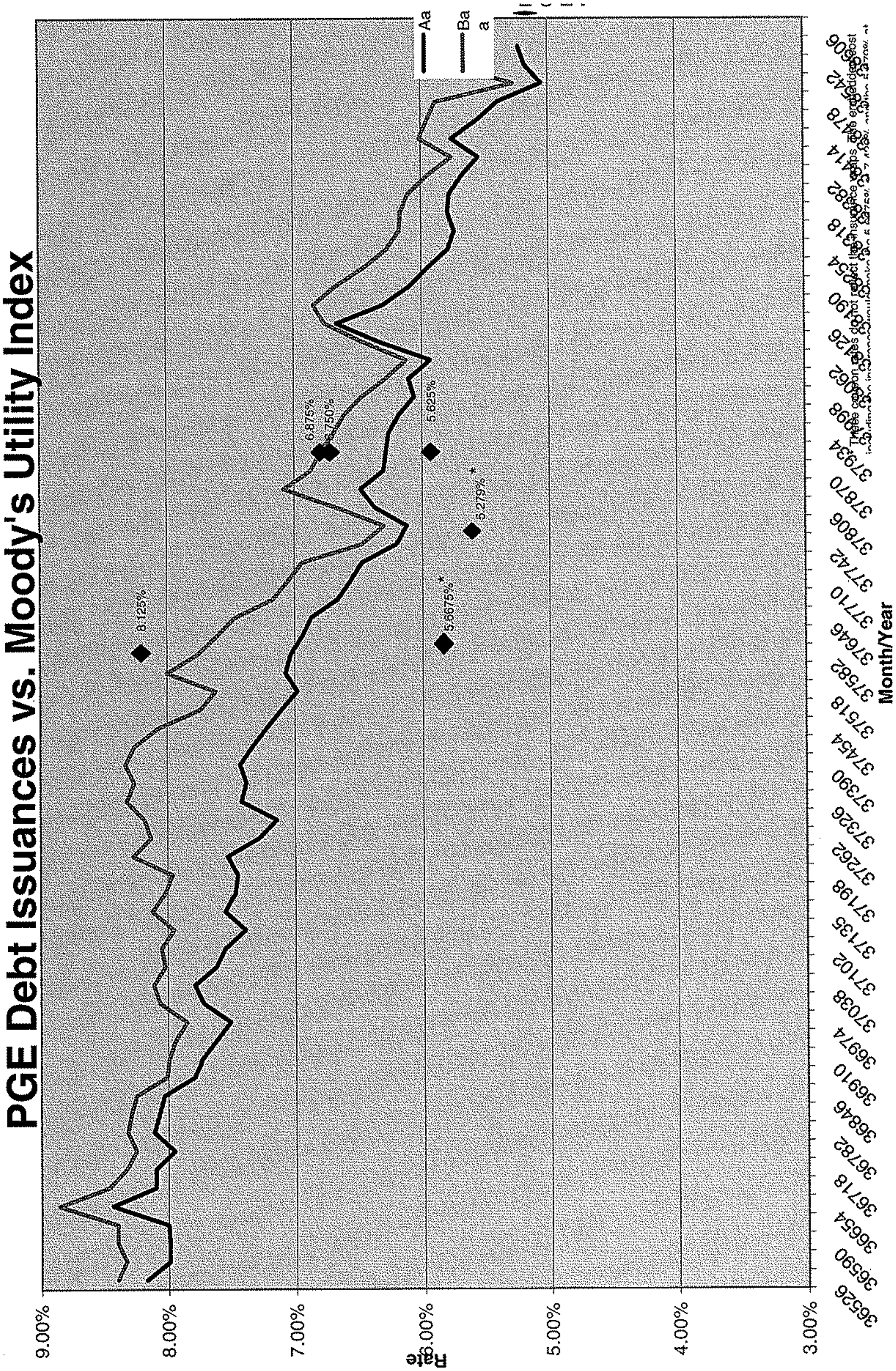
	A	BBB
Jan-99	6.55%	6.74%
Feb-99	6.77%	6.94%
Mar-99	6.95%	7.22%
Apr-99	6.85%	7.05%
May-99	7.23%	7.38%
Jun-99	7.64%	7.74%
Jul-99	7.57%	7.66%
Aug-99	7.87%	7.99%
Sep-99	7.99%	8.18%
Oct-99	8.19%	8.42%
Nov-99	8.03%	8.22%
Dec-99	8.30%	8.42%
Jan-00	8.46%	8.59%
Feb-00	8.03%	8.18%
Mar-00	8.13%	8.24%
Apr-00	8.19%	8.34%
May-00	8.70%	8.82%
Jun-00	8.56%	8.77%
Jul-00	8.50%	8.55%
Aug-00	8.27%	8.23%
Sep-00	8.31%	8.37%
Oct-00	8.31%	8.29%
Nov-00	8.15%	8.09%
Dec-00	8.15%	8.09%
Jan-01	8.11%	8.47%
Feb-01	7.92%	8.00%
Mar-01	7.87%	8.08%
Apr-01	8.14%	8.39%
May-01	8.27%	8.49%
Jun-01	8.09%	8.27%
Jul-01	8.07%	8.28%
Aug-01	7.91%	8.08%
Sep-01	7.88%	8.03%
Oct-01	7.67%	7.96%
Nov-01	7.75%	8.06%
Dec-01	8.19%	8.34%
Jan-02	8.11%	8.36%
Feb-02	8.02%	8.26%
Mar-02	8.25%	8.51%
Apr-02	8.08%	8.30%
May-02	7.97%	8.10%
Jun-02	7.62%	8.03%
Jul-02	7.61%	7.99%
Aug-02	7.36%	8.23%
Sep-02	6.90%	8.29%
Oct-02	7.01%	8.62%
Nov-02	6.58%	8.36%
Dec-02	6.33%	7.48%
Jan-03	6.39%	7.19%
Feb-03	6.01%	6.82%
Mar-03	5.91%	6.55%

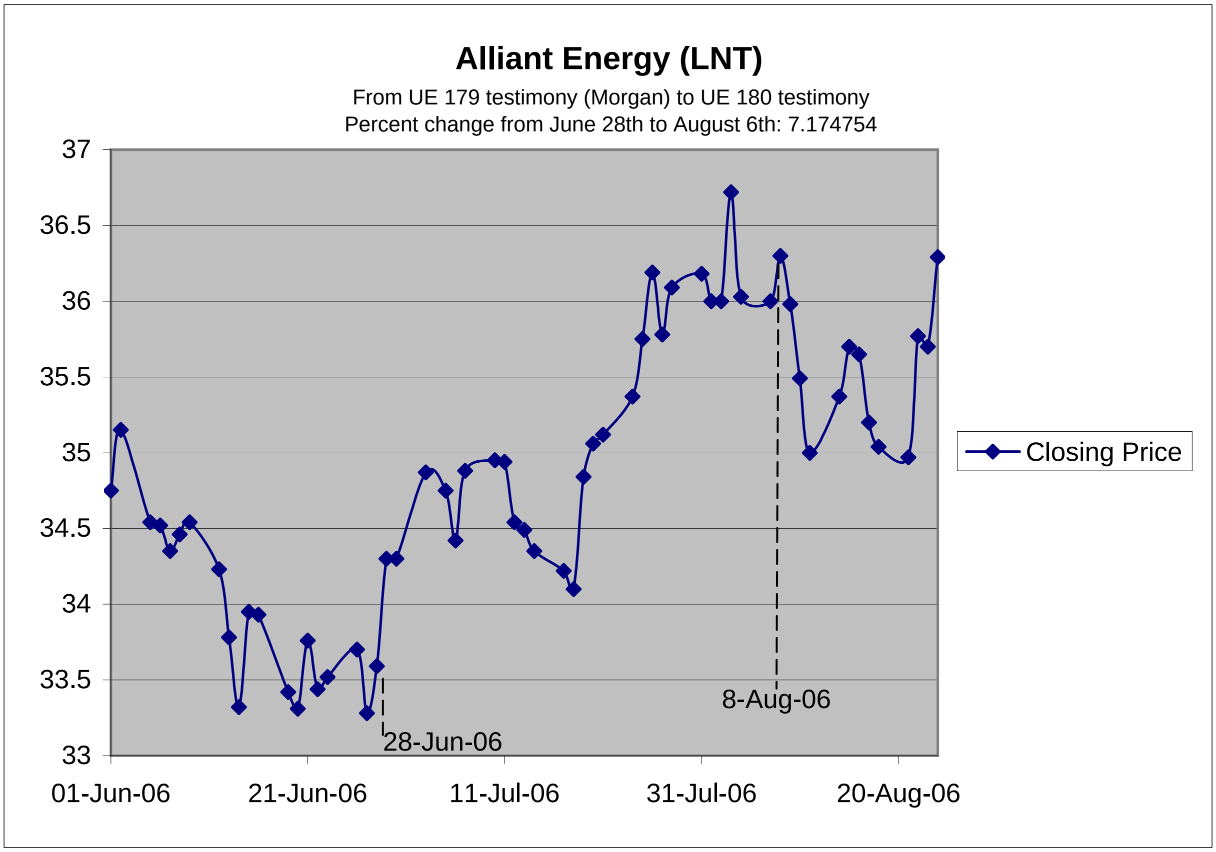
Apr-03	5.71%	6.82%
May-03	5.03%	6.17%
Jun-03	5.07%	5.69%
Jul-03	5.72%	6.38%
Aug-03	6.06%	6.74%
Sep-03	5.85%	6.29%
Oct-03	5.78%	6.14%
Nov-03	5.75%	6.02%
Dec-03	5.81%	6.00%
Jan-04	5.70%	5.79%
Feb-04	5.68%	5.69%
Mar-04	5.45%	5.46%

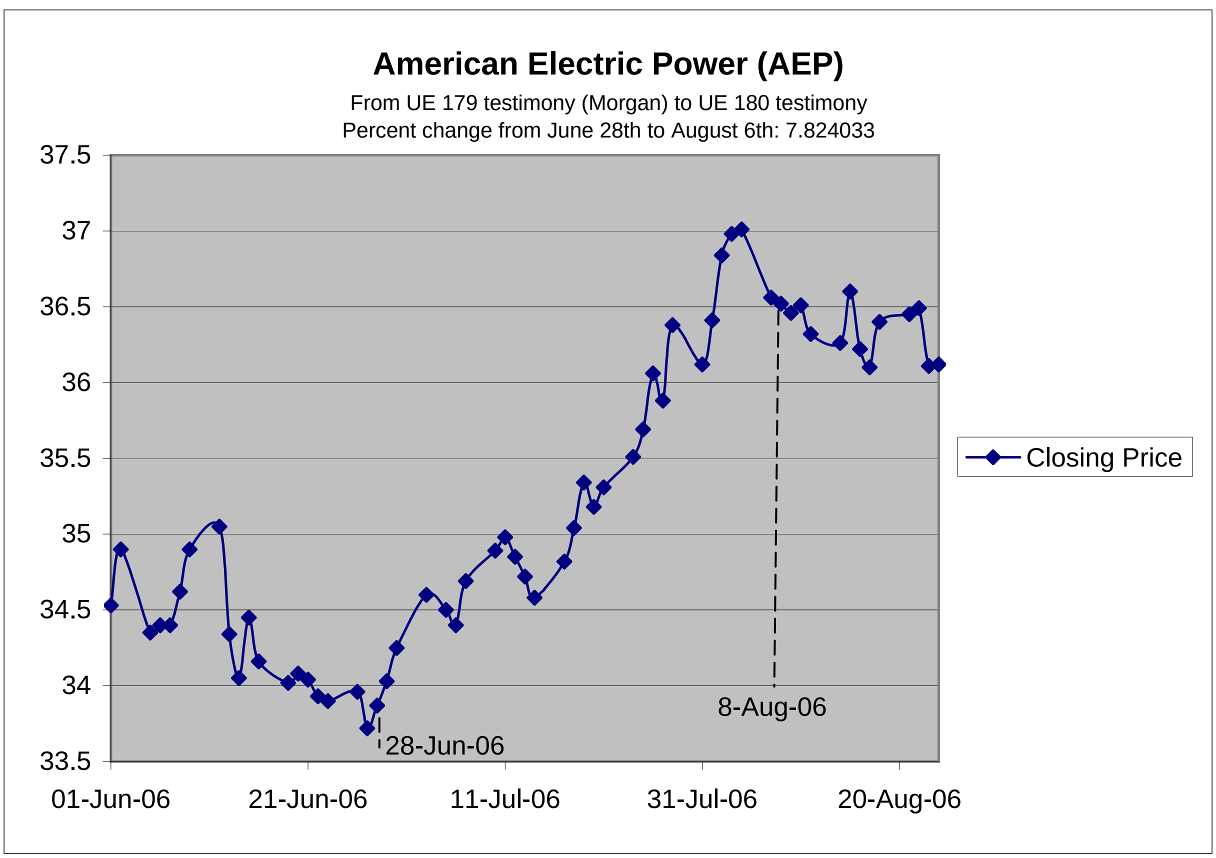

PGE Debt Issuances vs. S&P Utility Index
Rate
0.09
0.08
0.07
0.06
0.05
0.04
0.03
36526
36647
36770
36892
37012
37135
37257
37377
37500
37622
37742
37865
37987
Month/Year
A
BBB
PGE Debt Issuanc
8.125%
6.875%
6.750%
5.625%
5.6675% *
5.279% *
* These coupon rates do not reflect the insurance wraps. The embedded cost including the insurance would make the 5.6675% at 7.420% and the 5.279% at 6.434%

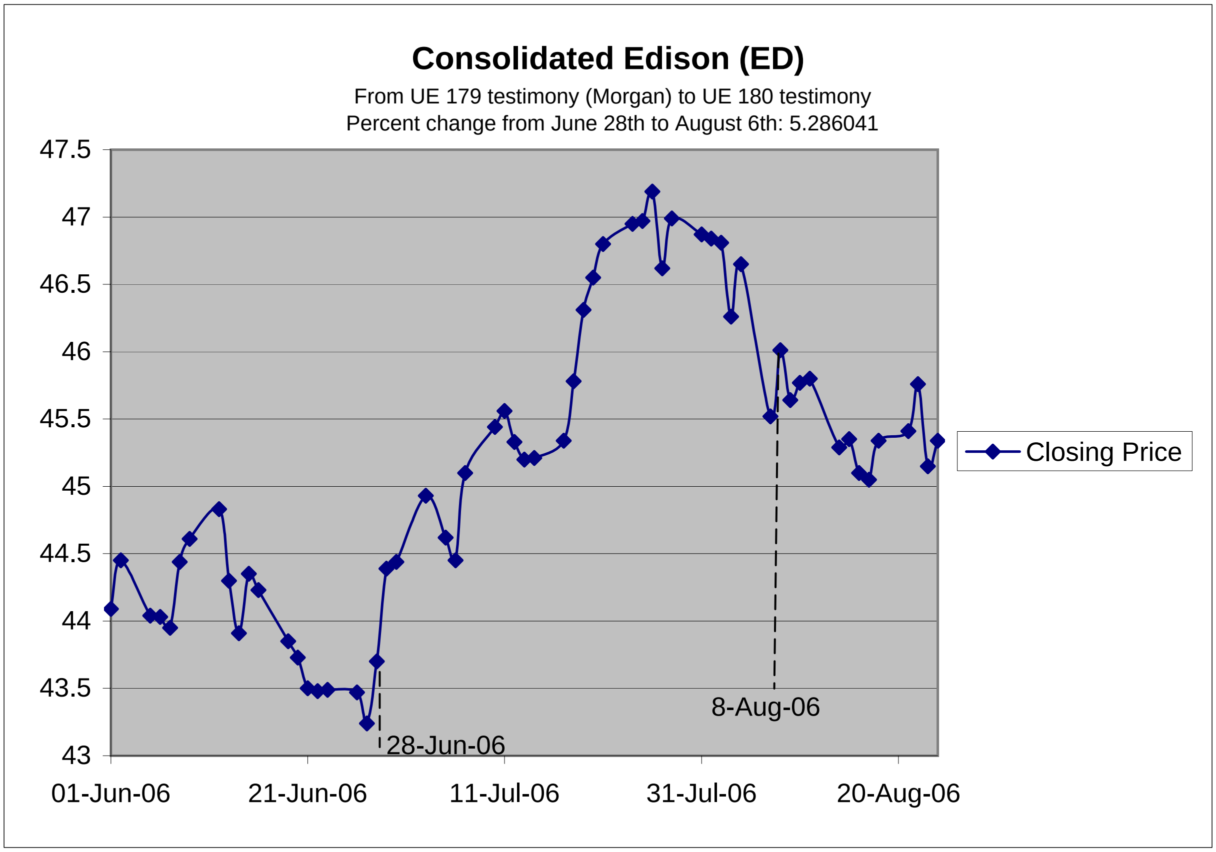
	Aa	Baa
Jan-00	8.17%	8.40%
Feb-00	7.99%	8.33%
Mar-00	7.99%	8.40%
Apr-00	8.00%	8.40%
May-00	8.44%	8.86%
Jun-00	8.10%	8.47%
Jul-00	8.10%	8.33%
Aug-00	7.95%	8.25%
Sep-00	8.11%	8.32%
Oct-00	8.07%	8.29%
Nov-00	8.03%	8.25%
Dec-00	7.79%	8.01%
Jan-01	7.73%	7.99%
Feb-01	7.62%	7.94%
Mar-01	7.51%	7.85%
Apr-01	7.72%	8.06%
May-01	7.79%	8.11%
Jun-01	7.62%	8.02%
Jul-01	7.55%	8.05%
Aug-01	7.39%	7.95%
Sep-01	7.55%	8.12%
Oct-01	7.47%	8.02%
Nov-01	7.45%	7.96%
Dec-01	7.53%	8.27%
Jan-02	7.28%	8.13%
Feb-02	7.14%	8.18%
Mar-02	7.42%	8.32%
Apr-02	7.38%	8.26%
May-02	7.43%	8.33%
Jun-02	7.33%	8.26%
Jul-02	7.22%	8.07%
Aug-02	7.10%	7.74%
Sep-02	6.98%	7.62%
Oct-02	7.07%	8.00%
Nov-02	7.03%	7.76%
Dec-02	6.94%	7.61%
Jan-03	6.87%	7.47%
Feb-03	6.66%	7.17%
Mar-03	6.56%	7.05%
Apr-03	6.47%	6.94%
May-03	6.20%	6.47%
Jun-03	6.12%	6.30%
Jul-03	6.37%	6.67%
Aug-03	6.48%	7.08%
Sep-03	6.30%	6.87%
Oct-03	6.28%	6.79%
Nov-03	6.26%	6.69%
Dec-03	6.18%	6.61%
Jan-04	6.06%	6.47%
Feb-04	6.10%	6.28%
Mar-04	5.93%	6.12%

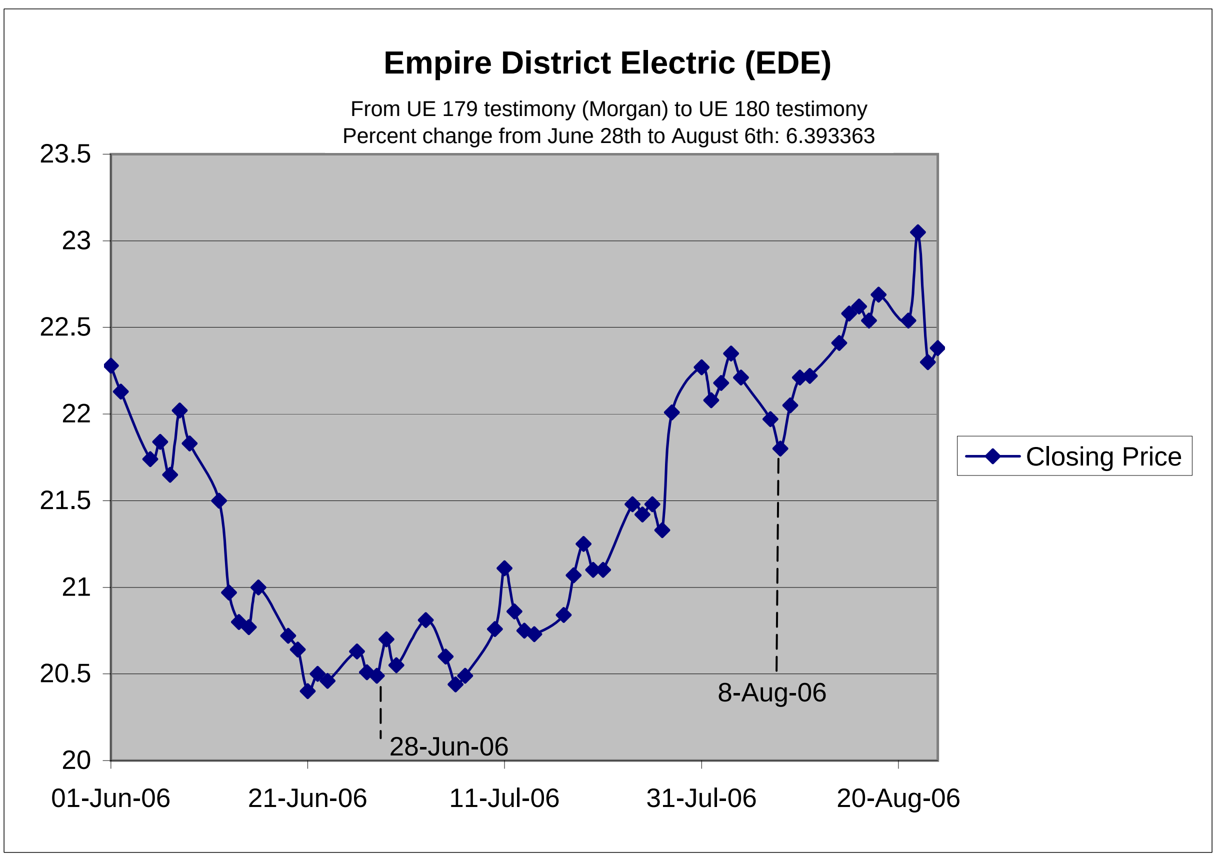
Apr-04	6.33%	6.46%
May-04	6.66%	6.75%
Jun-04	6.30%	6.84%
Jul-04	6.09%	6.67%
Aug-04	5.95%	6.45%
Sep-04	5.79%	6.27%
Oct-04	5.74%	6.17%
Nov-04	5.79%	6.16%
Dec-04	5.78%	6.10%
Jan-05	5.68%	5.95%
Feb-05	5.55%	5.76%
Mar-05	5.76%	6.01%
Apr-05	5.56%	5.95%
May-05	5.40%	5.88%
Jun-05	5.05%	5.27%
Jul-05	5.18%	5.81%
Aug-05	5.23%	5.80%
Sep-05	5.27%	5.83%

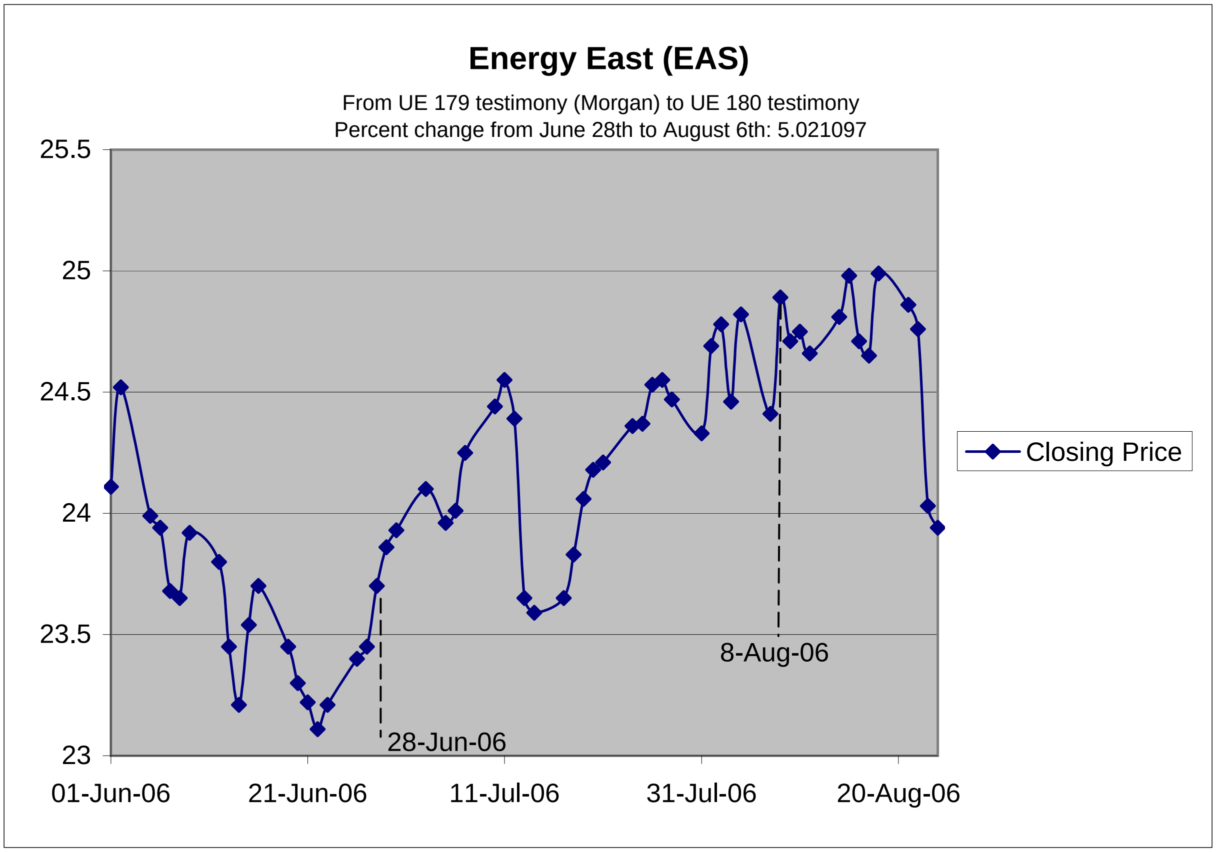

PGE Debt Issuances vs. Moody's Utility Index
Rate
9.00%
8.00%
7.00%
6.00%
5.00%
4.00%
3.00%
Month/Year
36526
36590
36654
36718
36782
36846
36910
36974
37038
37102
37135
37198
37262
37326
37390
37454
37518
37582
37646
37710
37742
37806
37870
37934
37998
38062
38126
38190
38254
38318
38382
38414
38478
38542
38606
Aa
Ba
a
8.125%
6.875%
6.750%
5.625%
5.279%
5.6675%

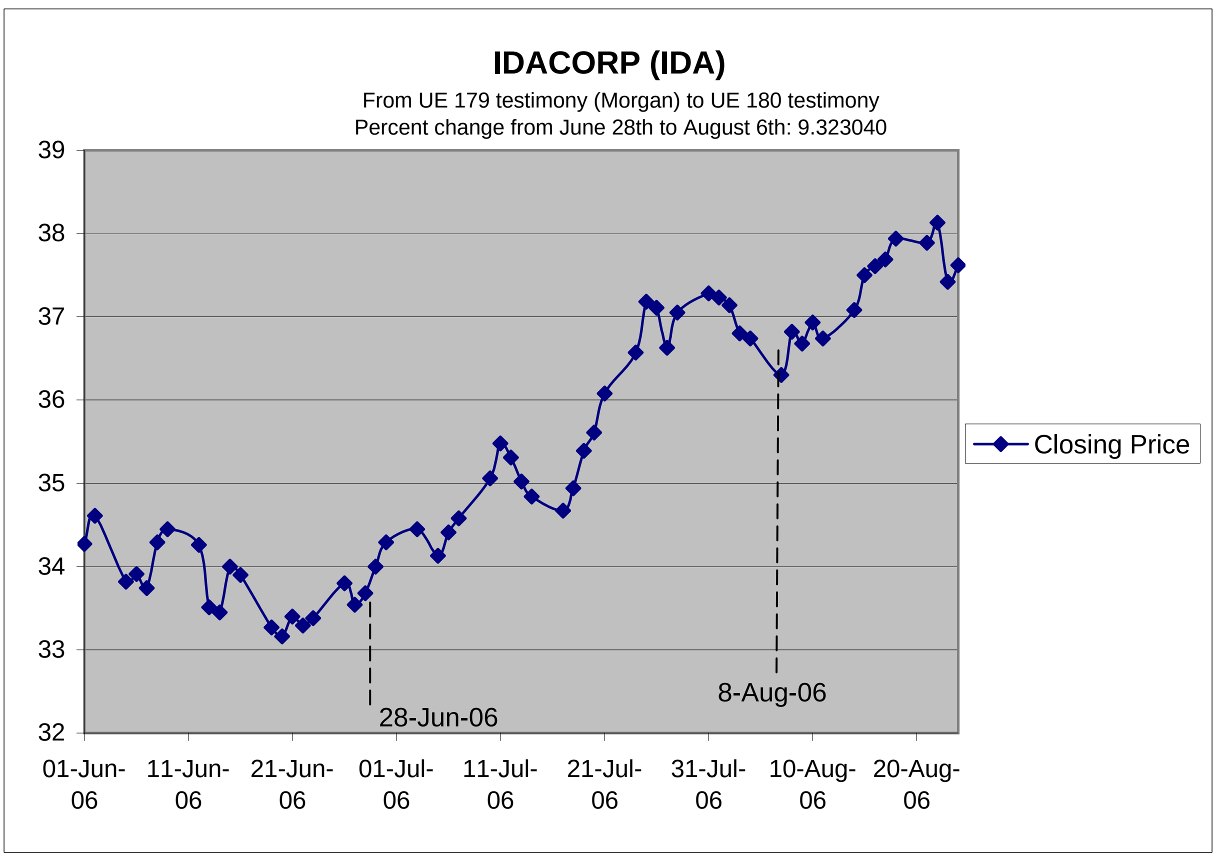

Alliant Energy (LNT)
From UE 179 testimony (Morgan) to UE 180 testimony
Percent change from June 28th to August 6th: 7.174754
37
36.5
36
35.5
35
34.5
34
33.5
33
01-Jun-06
21-Jun-06
11-Jul-06
31-Jul-06
20-Aug-06
28-Jun-06
8-Aug-06
Closing Price

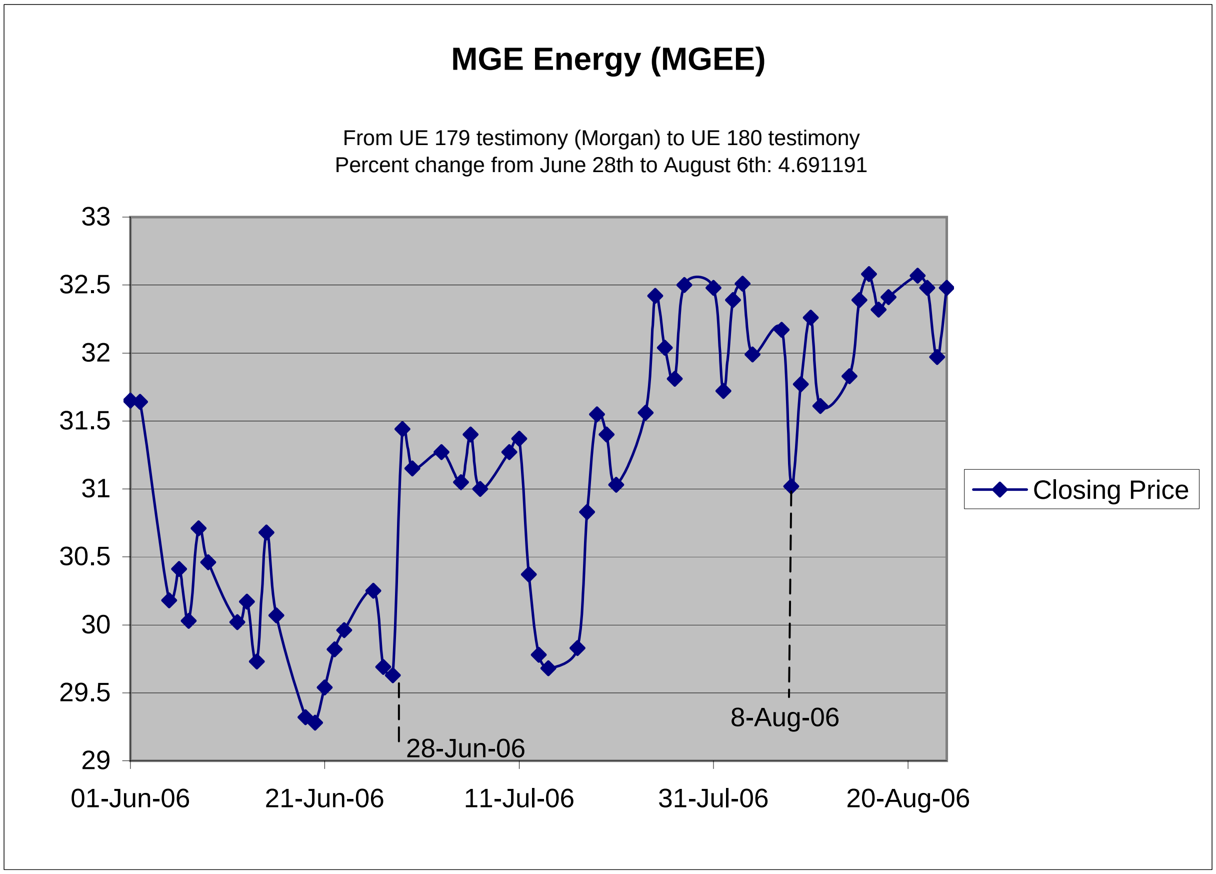

American Electric Power (AEP)
From UE 179 testimony (Morgan) to UE 180 testimony
Percent change from June 28th to August 6th: 7.824033
37.5
37
36.5
36
35.5
35
34.5
34
33.5
01-Jun-06
21-Jun-06
11-Jul-06
31-Jul-06
20-Aug-06
28-Jun-06
8-Aug-06
Closing Price

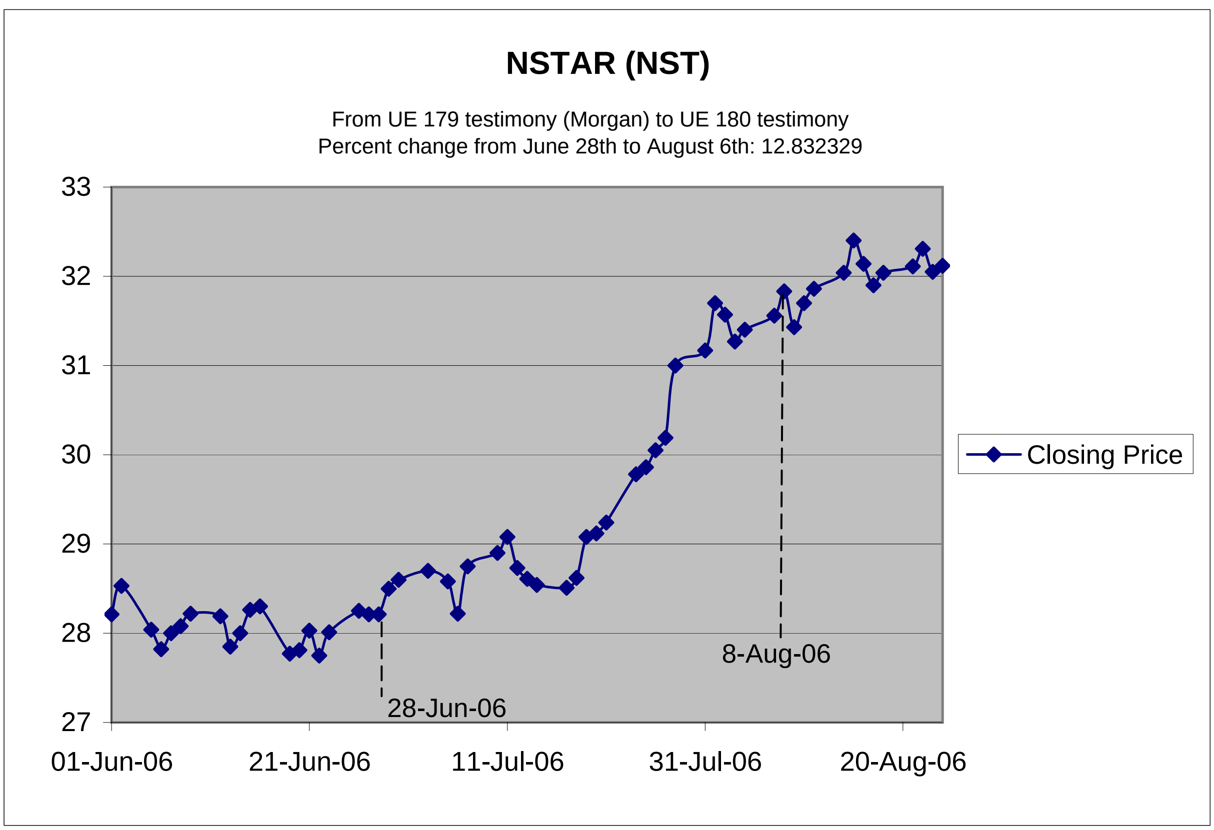

Consolidated Edison (ED)
From UE 179 testimony (Morgan) to UE 180 testimony
Percent change from June 28th to August 6th: 5.286041
47.5
47
46.5
46
45.5
45
44.5
44
43.5
43
28-Jun-06
8-Aug-06
01-Jun-06
21-Jun-06
11-Jul-06
31-Jul-06
20-Aug-06
Closing Price

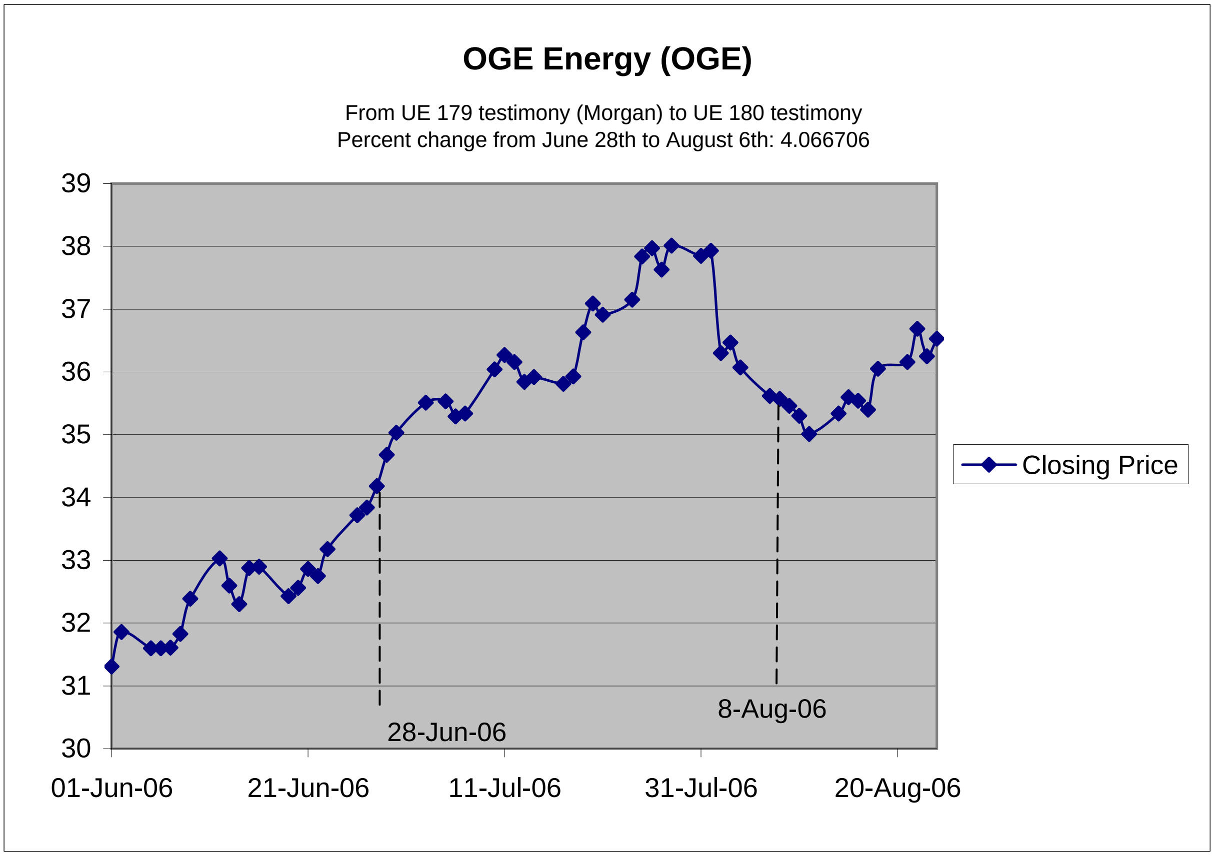

Empire District Electric (EDE)
From UE 179 testimony (Morgan) to UE 180 testimony
Percent change from June 28th to August 6th: 6.393363
23.5
23
22.5
22
21.5
21
20.5
20
28-Jun-06
8-Aug-06
01-Jun-06
21-Jun-06
11-Jul-06
31-Jul-06
20-Aug-06
Closing Price

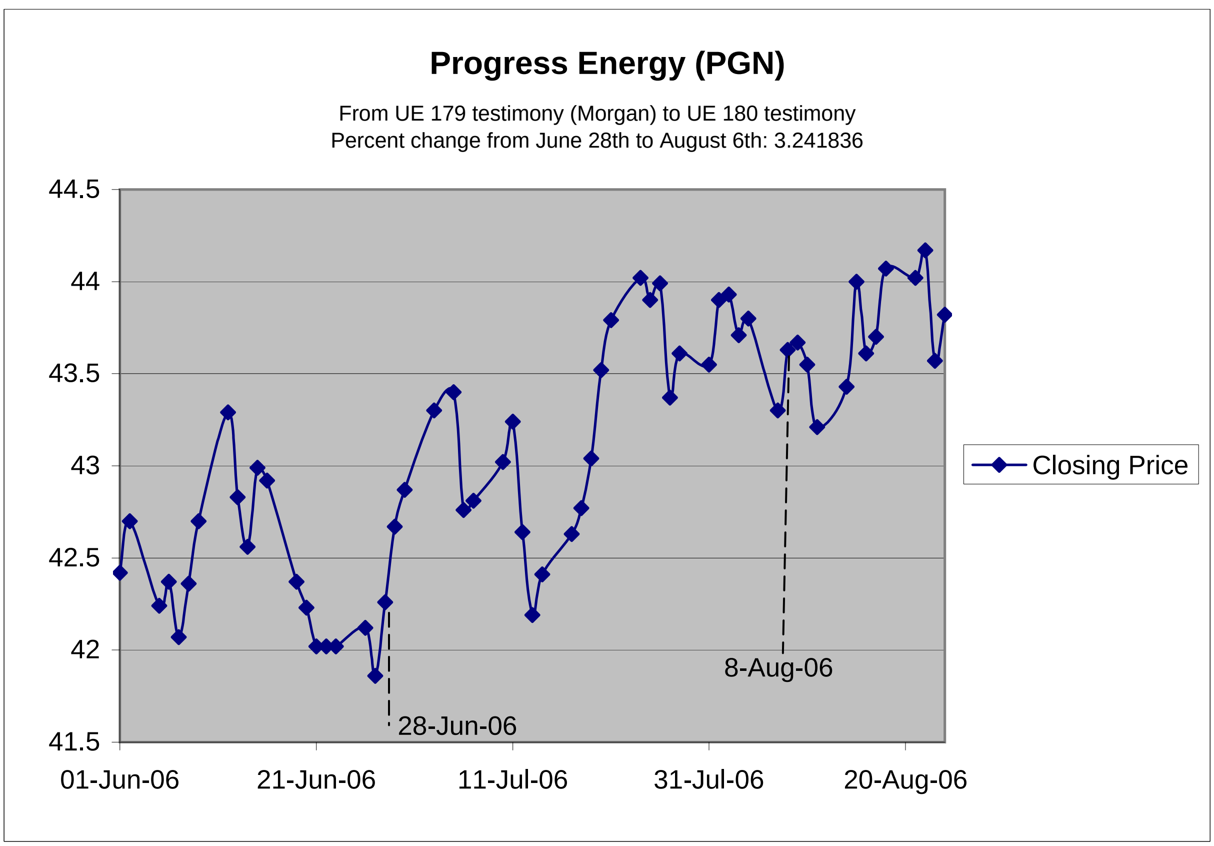

Energy East (EAS)
From UE 179 testimony (Morgan) to UE 180 testimony
Percent change from June 28th to August 6th: 5.021097
25.5
25
24.5
24
23.5
23
01-Jun-06
21-Jun-06
11-Jul-06
31-Jul-06
20-Aug-06
28-Jun-06
8-Aug-06
Closing Price

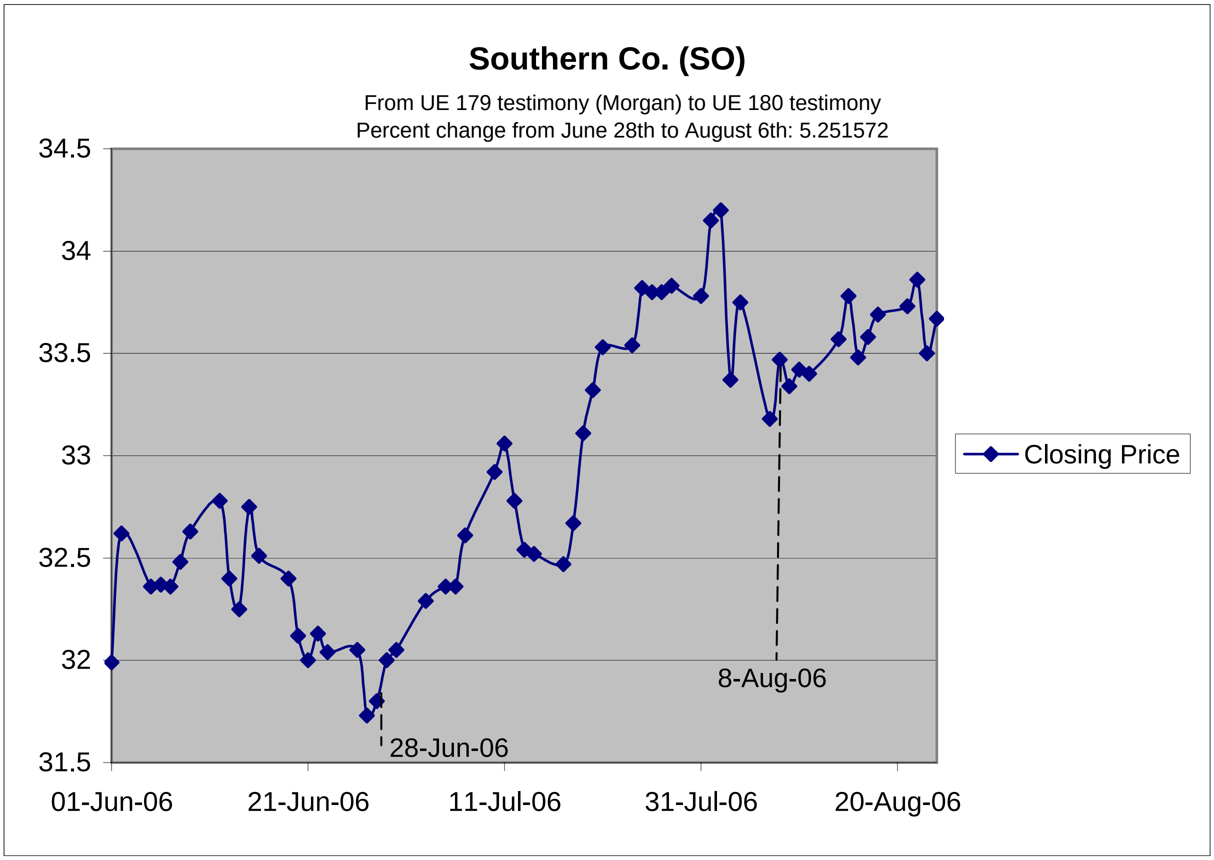

IDACORP (IDA)
From UE 179 testimony (Morgan) to UE 180 testimony
Percent change from June 28th to August 6th: 9.323040
39
38
37
36
35
34
33
32
01-Jun-06
11-Jun-06
21-Jun-06
01-Jul-06
11-Jul-06
21-Jul-06
31-Jul-06
10-Aug-06
20-Aug-06
28-Jun-06
8-Aug-06
Closing Price

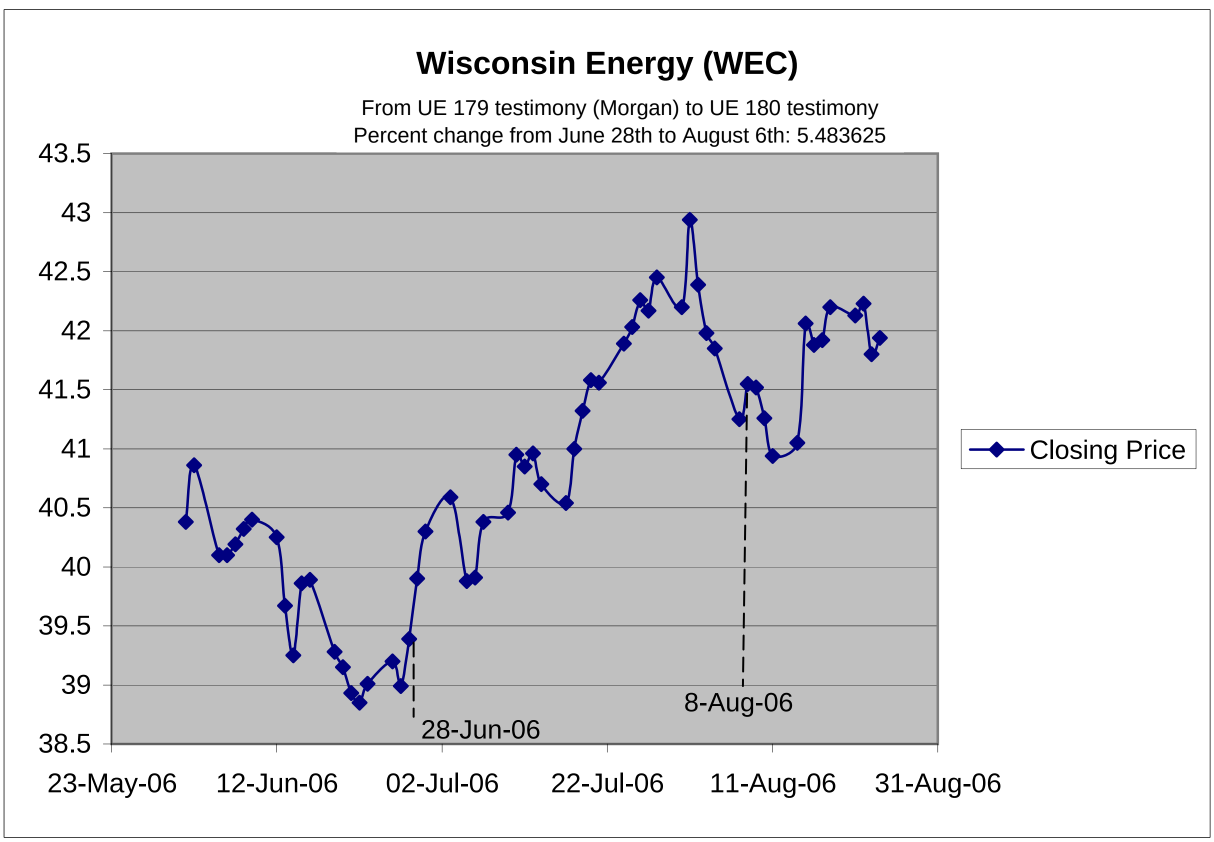

MGE Energy (MGEE)
From UE 179 testimony (Morgan) to UE 180 testimony
Percent change from June 28th to August 6th: 4.691191
33
32.5
32
31.5
31
30.5
30
29.5
29
28-Jun-06
8-Aug-06
01-Jun-06
21-Jun-06
11-Jul-06
31-Jul-06
20-Aug-06
Closing Price

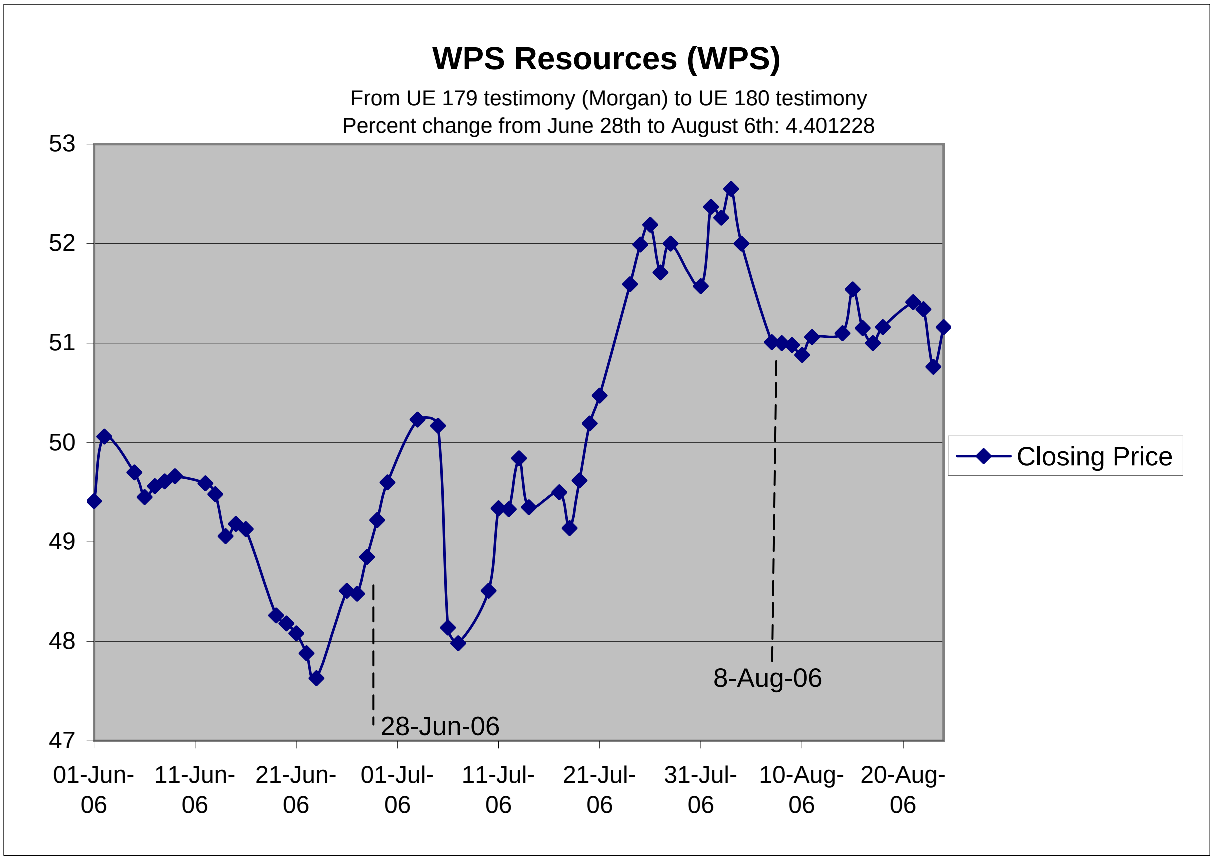

NSTAR (NST)
From UE 179 testimony (Morgan) to UE 180 testimony
Percent change from June 28th to August 6th: 12.832329
33
32
31
30
29
28
27
28-Jun-06
8-Aug-06
01-Jun-06
21-Jun-06
11-Jul-06
31-Jul-06
20-Aug-06
Closing Price

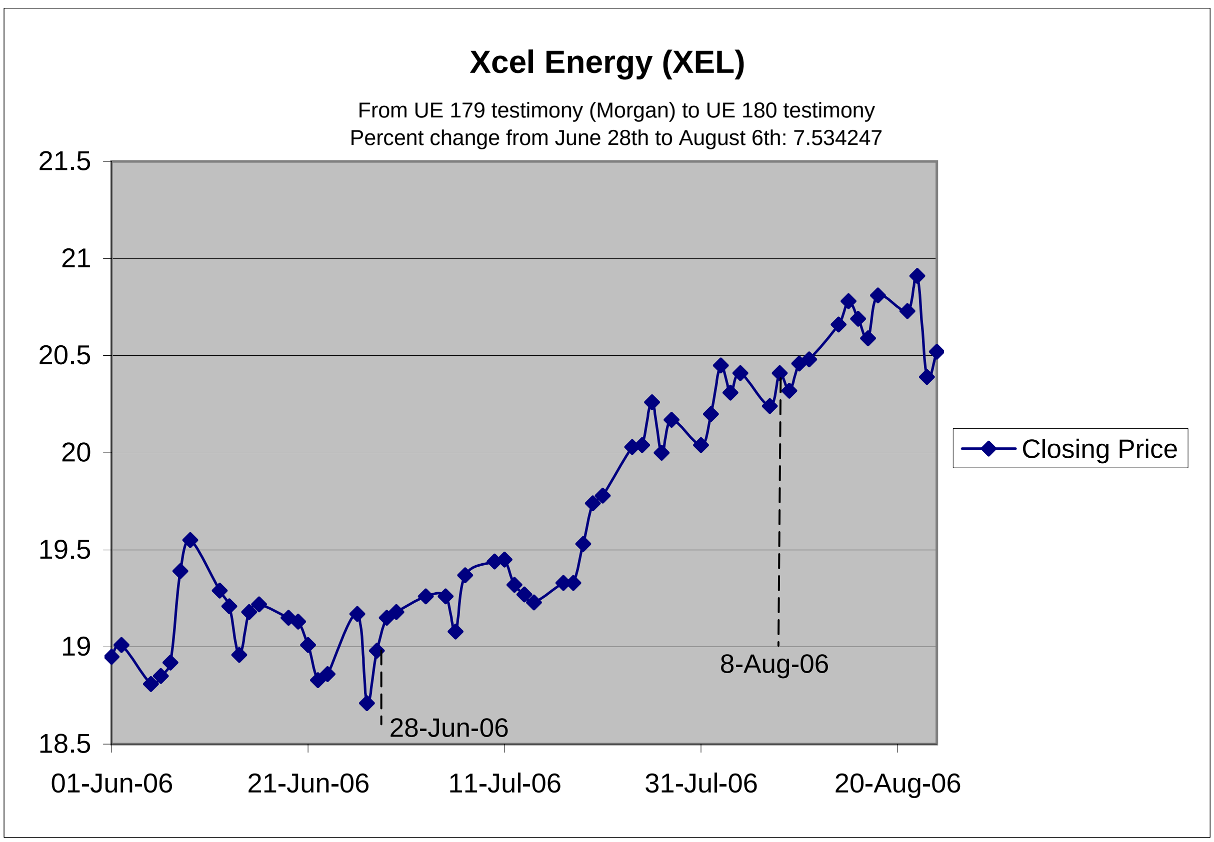

OGE Energy (OGE)
From UE 179 testimony (Morgan) to UE 180 testimony
Percent change from June 28th to August 6th: 4.066706
39
38
37
36
35
34
33
32
31
30
28-Jun-06
8-Aug-06
01-Jun-06
21-Jun-06
11-Jul-06
31-Jul-06
20-Aug-06
Closing Price


Progress Energy (PGN)
From UE 179 testimony (Morgan) to UE 180 testimony
Percent change from June 28th to August 6th: 3.241836
44.5
44
43.5
43
42.5
42
41.5
28-Jun-06
8-Aug-06
01-Jun-06
21-Jun-06
11-Jul-06
31-Jul-06
20-Aug-06
Closing Price


Southern Co. (SO)
From UE 179 testimony (Morgan) to UE 180 testimony
Percent change from June 28th to August 6th: 5.251572
34.5
34
33.5
33
32.5
32
31.5
8-Aug-06
28-Jun-06
01-Jun-06
21-Jun-06
11-Jul-06
31-Jul-06
20-Aug-06
Closing Price


Wisconsin Energy (WEC)
From UE 179 testimony (Morgan) to UE 180 testimony
Percent change from June 28th to August 6th: 5.483625
43.5
43
42.5
42
41.5
41
40.5
40
39.5
39
38.5
8-Aug-06
28-Jun-06
23-May-06
12-Jun-06
02-Jul-06
22-Jul-06
11-Aug-06
31-Aug-06
Closing Price


WPS Resources (WPS)
From UE 179 testimony (Morgan) to UE 180 testimony
Percent change from June 28th to August 6th: 4.401228
53
52
51
50
49
48
47
28-Jun-06
8-Aug-06
01-Jun-06
11-Jun-06
21-Jun-06
01-Jul-06
11-Jul-06
21-Jul-06
31-Jul-06
10-Aug-06
20-Aug-06
Closing Price


Xcel Energy (XEL)
From UE 179 testimony (Morgan) to UE 180 testimony
Percent change from June 28th to August 6th: 7.534247
21.5
21
20.5
20
19.5
19
18.5
28-Jun-06
8-Aug-06
01-Jun-06
21-Jun-06
11-Jul-06
31-Jul-06
20-Aug-06
Closing Price

Risk Positioning Method (Data through 12/05)

Example demonstrating equivalence of two models

First model: AuthorizedROE = Intercept + (constant*7yrT-Bonds lag 1 month)

Bond rate for example = 5.22

7yr Treasury yields 1983-2005 (1 month lag)

R-Square 0.7057

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.4471	0.1334	63.34	<.0001
yr71	0.5534	0.0162	34.07	<.0001

Implied ROE 2007:
11.336

ROE CALCULATION:

AROE = intercept + cons * 7yrBondEst

MRP = AROE - 7yrBondEst

MRP = intercept + (cons-1) * 7yrBondEst

>> IMPLIEDROE = 7yrBondEst + MRP <<

Second model: MRP = Intercept + (constant*7yrT-Bonds lag 1 month)

Bond rate for example = 5.22

7yr Treasury yields 1983-2005 (1 month lag)

R-Square 0.5063

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.4471	0.1334	63.34	<.0001
yr71	-0.4466	0.0162	-27.49	<.0001

Implied ROE 2007:
11.336

ROE CALCULATION:

MRP = intercept + cons * 7yrBondEst

>> IMPLIEDROE = 7yrBondEst + MRP <<

	Adjusted R^2 When Dependent Variable is	
	MRP	Authorized ROE
Trial 1	0.560647266	0.001490877
Trial 2	0.670943384	0.027124441
Trial 3	0.532282999	-0.020322392
Trial 4	0.402422470	-0.023579290
Trial 5	0.470762799	-0.019422120
Trial 6	0.435921031	-0.013316265
Trial 7	0.531782120	-0.019654988
Trial 8	0.463624800	-0.012336638
Trial 9	0.573457859	-0.018458538
Trial 10	0.452993494	-0.020221065

Risk Positioning Method (Data through 12/05)
Using *Global Insight* Forecast

rate = 5.22

7yr Treasury yields 1983-2005 (1 month lag)

R-Square 0.6095

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.44787	0.13651	61.89	<.0001
yr71	-0.4458	0.01648	-27.06	<.0001

Implied ROE 2007:
11.341

---

rate = 5.22

7yr Treasury yields 1983-2005 (7 month lag)

R-Square 0.6458

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.16655	0.12543	65.11	<.0001
yr77	-0.4293	0.01468	-29.24	<.0001

Implied ROE 2007:
11.1456

Using January 2006 Interest Rates

rate = 4.60

7yr Treasury yields 1983-2005 (1 month lag)

R-Square 0.6095

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.44787	0.13651	61.89	<.0001
yr71	-0.4458	0.01648	-27.06	<.0001

Implied ROE 2007:
10.9973

---

rate = 4.60

7yr Treasury yields 1983-2005 (7 month lag)

R-Square 0.6458

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.16655	0.12543	65.11	<.0001
yr77	-0.4293	0.01468	-29.24	<.0001

Implied ROE 2007:
10.7918

Using Corporate Bond Rates

PGE Estimate FMB Bond rate = 6.15
Moody's Baa Utility Nov 05 rate = 6.14

Corporate Bonds 1983-2005

R-Square 0.6315

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	6.44697	0.16874	38.21	<.0001
debtcost	-0.34408	0.01692	-20.33	<.0001

	Implied ROE 2007:
PGE	10.4809
Moodys	10.4743

TOTAL ROE (average) = 10.8718

YEARS 2001-2005 (to account for new wholesale power market conditions)

Risk Positioning Method (Data through 12/05)
Using *Global Insight* Forecast

rate = 5.22
Obs = 53

7yr Treasury yields 2001-2005 (1 month lag)

R-Square 0.2371

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	10.3593	0.91682	11.3	<.0001
yr71	-0.847	0.22648	-3.74	0.0005

Implied ROE 2007:
11.1581

---

rate = 5.22
Obs = 53

7yr Treasury yields 2001-2005 (7 month lag)

R-Square 0.2371

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	9.43318	0.93233	10.12	<.0001
yr77	-0.6251	0.22514	-2.78	0.008

Implied ROE 2007:
11.3903

YEARS 2001-2005 (to account for new wholesale power market conditions)

Using January 2006 Interest Rates

rate = 4.60
Obs = 53

7yr Treasury yields 2001-2005 (1 month lag)

R-Square 0.2371

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	10.3593	0.91682	11.3	<.0001
yr71	-0.847	0.22648	-3.74	0.0005

Implied ROE 2007:
11.0632

---

rate = 4.60
Obs = 53

7yr Treasury yields 2001-2005 (7 month lag)

R-Square 0.6315

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	9.43318	0.93223	10.12	<.0001
yr77	-0.62508	0.22514	-2.78	0.008

Implied ROE 2007:
11.1578

YEARS 2001-2005 (to account for new wholesale power market conditions)

Using Corporate Bond Rates

	PGE Estimate FMB Bond	rate = 6.15			
	Moody's Baa Utility Nov 05	rate = 6.14		Obs = 53	
Corporate Bonds 2001-2005					
	R-Square	0.6315			

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|		Implied ROE 2007:
Intercept	10.8307	0.73489	14.74	<.0001	PGE	10.9657
debtcost	-0.9781	0.11138	-8.78	<.0001	Moodys	10.9655

TOTAL ROE (average) = 11.1168

YEARS 1990-2005 (Removed high inflation 1980s as precaution)

Risk Positioning Method (Data through 12/05)

Using *Global Insight* Forecast

rate = 5.22

7yr Treasury yields 1990-2005 (1 month lag)

R-Square 0.6095

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	9.81497	0.209	46.96	<.0001
yr71	-0.7116	0.03451	-20.62	<.0001

Implied ROE 2007: 11.3206

rate = 5.22

7yr Treasury yields 1990-2005 (7 month lag)

R-Square 0.6458

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	9.63996	0.19373	49.76	<.0001
yr77	-0.6938	0.03075	-22.56	<.0001

Implied ROE 2007: 11.2384

YEARS 1990-2005 (Removed high inflation 1980s as precaution)

Using January 2006 Interest Rates

rate = 4.60

7yr Treasury yields 1990-2005 (1 month lag)

R-Square 0.6095

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	9.81497	0.209	46.96	<.0001
yr71	-0.7116	0.03451	-20.62	<.0001

Implied ROE 2007:
11.1418

---

rate = 4.60

7yr Treasury yields 1990-2005 (7 month lag)

R-Square 0.6458

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	9.63996	0.19373	49.76	<.0001
yr77	-0.6938	0.03075	-22.56	<.0001

Implied ROE 2007:
11.0486

YEARS 1990-2005 (Removed high inflation 1980s as precaution)

Using Corporate Bond Rates

	PGE Estimate FMB Bond	rate = 6.15
	Moody's Baa Utility Nov 05	rate = 6.14
Corporate Bonds 1990-2005		
	R-Square	0.6315

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|		Implied ROE 2007:
Intercept	8.8532	0.30649	28.89	<.0001	PGE	10.9209
debtcost	-0.6638	0.03782	-17.55	<.0001	Moodys	10.9175

TOTAL ROE (average) = 11.098

GRAND AVERAGE = 11.0288

ADJUSTED DATA **(removed high influence)**

Risk Positioning Method (Data through 12/05)

Using *Global Insight* Forecast

rate = 5.22

7yr Treasury yields 1983-2005 (1 month lag)

R-Square 0.6806

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.3863	0.12	69.87	<.0001
yr71	-0.4449	0.0145	-30.73	<.0001

Implied ROE 2007:
11.284

---

rate = 5.22

7yr Treasury yields 1983-2005 (7 month lag)

R-Square 0.6949

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.2	0.1177	69.66	<.0001
yr717	-0.4387	0.0138	-31.76	<.0001

Implied ROE 2007:
11.13

ADJUSTED DATA

Using January 2006 Interest Rates

rate = 4.60

7yr Treasury yields 1983-2005 (1 month lag)

R-Square 0.6806

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.3863	0.12	69.87	<.0001
yr71	-0.4449	0.0145	-30.73	<.0001

Implied ROE 2007:
10.94

---

rate = 4.60

7yr Treasury yields 1983-2005 (1 month lag)

R-Square 0.6949

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.2	0.1177	69.66	<.0001
debtcost	-0.4387	0.0138	-31.76	<.0001

Implied ROE 2007:
10.782

ADJUSTED DATA
Using Corporate Bond Rates

	PGE Estimate FMB Bond	rate = 6.15
	Moody's Baa Utility Nov 05	rate = 6.14
Corporate Bonds 1983-2005		
	R-Square	0.6315

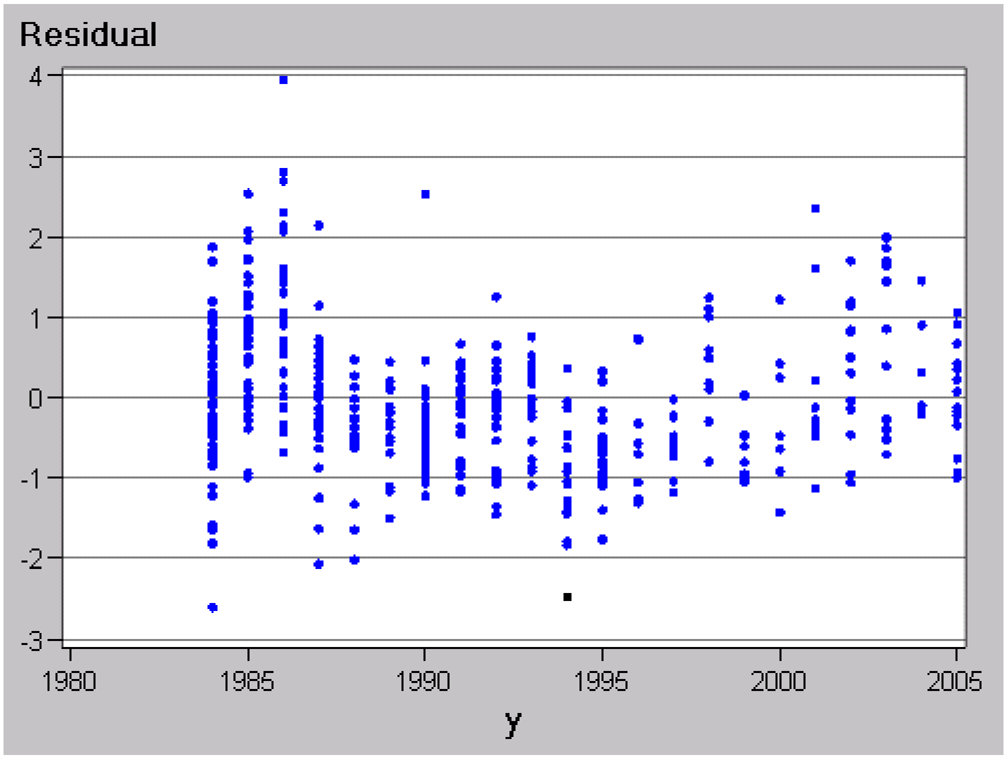
Parameter Estimates

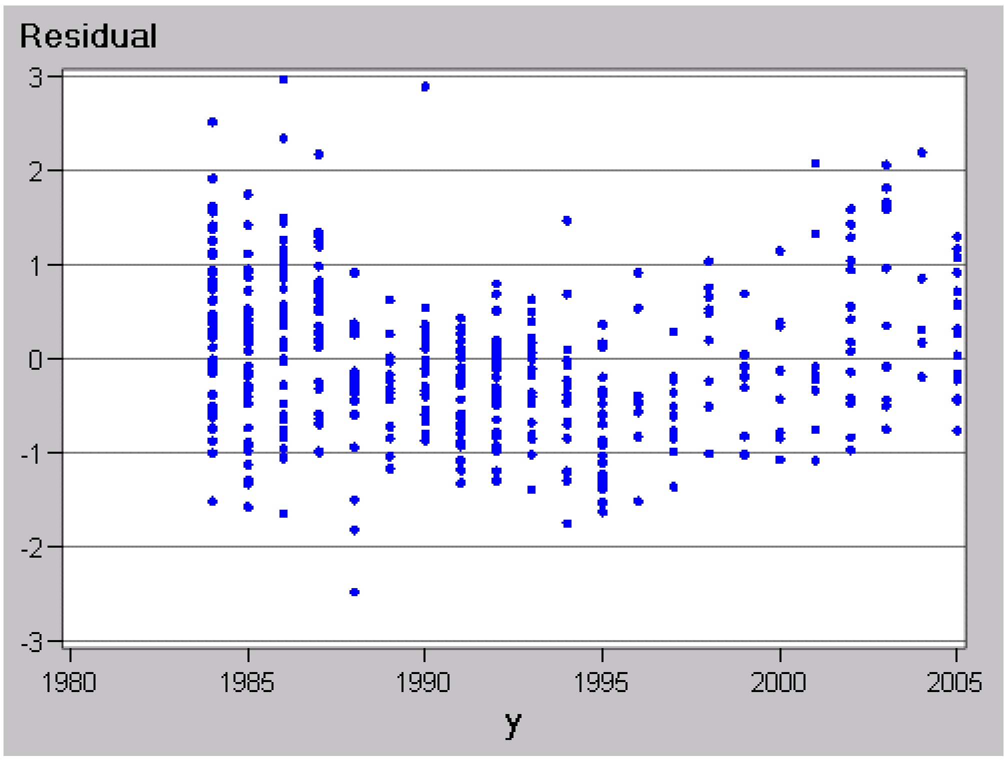
Variable	Estimate	Error	t Value	Pr > |t|
Intercept	6.5173	0.1557	41.87	<.0001
debtcost	-0.3553	0.0157	-22.71	<.0001

	Implied ROE 2007:
PGE	10.482
Moodys	10.476

TOTAL ROE (average) = 10.849

1 RESIDUAL PLOT OF MODEL RISKP = a + b*(7 year T bond lag 1 mo.) + residual





2 RESIDUAL PLOT OF MODEL RISKP = a + b*(7 year T bond lag 7 mo.) + residual

MODEL SPECIFIED USING MINIMIZED AIC

Note-- assumption made that rates will hold constant

Risk Positioning Method (Data through 12/05)

Using *Global Insight* Forecast

rate = 5.22

*NOTE: AROE regressed instead of MRP due to specification

7yr Treasury yields 1983-2005

R-Square 0.7866 *

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	7.9082	0.1216	65.02	<.0001
yr71	0.1542	0.0567	2.72	0.0068
yr74	0.1372	0.0692	1.98	0.048
yr79	0.1506	0.0805	1.87	0.0621
yr711	-0.3213	0.1449	-2.22	0.027
yr712	0.4874	0.1153	4.23	<.0001

Implied ROE 2007:
11.082

Using January 2006 Interest Rates

rate = 4.60

7yr Treasury yields 1983-2005

R-Square 0.7866 *

ROE AVERAGE = 10.89396

ROE AVERAGE from single variable models = 11.06891

*note this comparison removes corporate bonds

Difference of : 0.1749481

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	7.9082	0.1216	65.02	<.0001
yr71	0.1542	0.0567	2.72	0.0068
yr74	0.1372	0.0692	1.98	0.048
yr79	0.1506	0.0805	1.87	0.0621
yr711	-0.3213	0.1449	-2.22	0.027
yr712	0.4874	0.1153	4.23	<.0001

Implied ROE 2007:
10.705

ADDING CPI AS PROXY FOR ECONOMIC ENVIRONMENT

Risk Positioning Method (Data through 12/05)

Using *Global Insight* Forecast and CPI from St. Louis Fed

rate = 5.22
CPI = 203.2 (July 2006)

7yr Treasury yields 1983-2005 (1 month lag)

R-Square 0.6429

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	12.238	0.5795	21.12	<.0001
yr71	-0.6162	0.0297	-20.75	<.0001
CPI	-0.0182	0.0027	-6.71	<.0001

Implied ROE 2007: 10.539

7yr Treasury yields 1983-2005 (7 month lag)

R-Square 0.6556

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	10.157	0.5967	17.02	<.0001
yr77	-0.5209	0.0298	-17.48	<.0001
CPI	-0.0093	0.0028	-3.35	0.0009

Implied ROE 2007: 10.776

ADDING CPI AS PROXY FOR ECONOMIC ENVIRONMENT

Using January 2006 interest rates and CPI from St. Louis Fed

rate = 4.6
CPI = 203.2 (July 2006)

7yr Treasury yields 1983-2005 (1 month lag)

R-Square 0.6429

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	12.238	0.5795	21.12	<.0001
yr71	-0.6162	0.0297	-20.75	<.0001
CPI	-0.0182	0.0027	-6.71	<.0001

Implied ROE 2007:
10.301

7yr Treasury yields 1983-2005 (7 month lag)

R-Square 0.6556

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	10.157	0.5967	17.02	<.0001
yr77	-0.5209	0.0298	-17.48	<.0001
CPI	-0.0093	0.0028	-3.35	0.0009

Implied ROE 2007:
10.479

ADDING CPI AS PROXY FOR ECONOMIC ENVIRONMENT

Using corporate bonds and CPI from St. Louis Fed

PGE Estimate FMB Bond rate = 6.15
Moody's Baa Utility Nov 05 rate = 6.14
CPI = 203.2 (July 2006)

Corporate Bonds 1983-2005

R-Square 0.6429

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.7609	0.6857	12.78	<.0001
yr71	-0.4482	0.0343	-13.07	<.0001
CPI	-0.0097	0.0028	-3.48	0.0006

	Implied ROE 2007:
PGE	10.183
Moody's	10.178

TOTAL ROE (average): 10.409

Different treasury bonds

Risk Positioning Method (Data through 12/05)
Using *Global Insight* Forecast

rate = 5.22

10yr Treasury yields 1983-2005 (1 month lag)

R-Square 0.5824

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.2361	0.1377	59.82	<.0001
yr101	-0.4298	0.0165	-25.98	<.0001

Implied ROE 2007:
11.213

rate = 5.22

10yr Treasury yields 1983-2005 (7 month lag)

R-Square 0.6187

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	7.9886	0.1276	62.61	<.0001
yr107	-0.4171	0.0149	-28.03	<.0001

Implied ROE 2007:
11.031

Using January 2006 Interest Rates

rate = 4.60

10yr Treasury yields 1983-2005 (1 month lag)

R-Square 0.5824

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	8.23607	0.13768	59.82	<.0001
yr101	-0.42975	0.01654	-25.98	<.0001

Implied ROE 2007:
10.859

---

rate = 4.60

10yr Treasury yields 1983-2005 (7 month lag)

R-Square 0.6187

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	7.9886	0.1276	62.61	<.0001
yr107	-0.4171	0.0149	-28.03	<.0001

Implied ROE 2007:
10.67

Risk Positioning Method (Data through 12/05)

Using *Global Insight* Forecast

rate = 5.22

30yr Treasury yields 1983-2002 (1 month lag) **30 year rates unavailable 2002-2005

R-Square 0.4798

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	7.691	0.154	49.96	<.0001
yr301	-0.3817	0.0181	-21.13	<.0001

Implied ROE 2007:
10.919

rate = 5.22

30yr Treasury yields 1983-2002 (7 month lag) **30 year rates unavailable 2002-2005

R-Square 0.5133

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	7.4265	0.1425	52.11	<.0001
yr307	-0.3677	0.0163	-22.59	<.0001

Implied ROE 2007:
10.727

Using January 2006 Interest Rates

rate = 4.60

30yr Treasury yields 1983-2002 (1 month lag) **30 year rates unavailable 2002-2005

R-Square 0.4798

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	7.691	0.154	49.96	<.0001
yr301	-0.3817	0.0181	-21.13	<.0001

Implied ROE 2007: 10.535

---

rate = 4.60

30yr Treasury yields 1983-2002 (7 month lag) **30 year rates unavailable 2002-2005

R-Square 0.5133

Parameter Estimates

Variable	Estimate	Error	t Value	Pr > |t|
Intercept	7.4265	0.1425	52.11	<.0001
yr307	-0.3677	0.0163	-22.59	<.0001

Implied ROE 2007: 10.335

Exhibit 20&&_OPUC Staff's Response to PGE Data Requests

OPUC Staff's Response to PGE Data Requests: 23, 33, 38, 42, 53, 65

23. Please explain the basis for the statement at page 24, lines 8-9 that "there is a lot of evidence that risk premiums may be time-varying." Please identify such evidence, and provide any reports, analyses, studies or other documents which support or relate to this statement.

<u>Staff Response:</u>

This is based on Mr. Morgan's knowledge and was not based on a contemporaneous analysis of the literature. However, please see Staff/1003 Morgan/270 and 273 for examples and data regarding changing market risk premiums.

33. Referring to the tables at Staff/1000 Morgan/15-16, why does Mr. Morgan include utilities that have recently experienced, or are expected to experience, negative growth in earnings, dividends, and/or book value?

Staff Response:

Growth rates were not used in the filtering process.

38. Referring to Staff/1000 Morgan 24, please provide the "published risk premium literature" mentioned at line 6. If already provided, please list the relevant exhibit(s) and page numbers.

Staff Response:

See Staff's response to Data Request 23.

42. Referring to Staff/1003 Morgan/35, it states that "Oregon has provided a favorable regulatory environment that has responded quickly to changing market conditions that affect its regulatory enterprises." Please provide all relevant, specific, and measurable examples of the "favorable regulatory environment," including specific dockets, dates, page numbers, etc. Please provide any third-party publications or resources of which Staff is aware, or on which Staff relied, which support or relate to this statement.

Staff Response:

Staff does not have the requested reports. Staff is aware that S&P, Value Line and Regulatory Research Associates, among others, considers Oregon's regulatory treatment to be favorable.

Staff Response to PGE's Fourth Set of Data Requests 53 - 82
August 31, 2006
Page 1

53. Referring to Staff/1003 Morgan/4, when discussing interest rates, Mr. Morgan states "most analysts do not expect significant upward pressure."
   a. Please indicate what is meant by "most analysts"? More than 50%?
   b. Please provide all reports, analyses, studies, journals, or other documents on which Mr. Morgan relied in making this statement.

Staff Response:

Staff is referring to its perception of the current interest rate environment, including the recent actions by the Federal Reserve Board, as an indication that interest rates should remain reasonably stable. For additional information, see Staff/1003 Morgan/407.

65. What is the basis for the statement at Staff/1003 Morgan/28 that "some published literature provides the arithmetic average, for rate-making purposes"? Please provide such published literature, including all reports, analyses, studies, journals, or other documents on which Mr. Morgan relied in making this statement.

Staff Response:

Staff is not aware of specific published literature upon which the statement was based.

Exhibit 2021

Conway Deposition
Page 20

will.

A And my answer is no.

Q That's not your testimony.

A Correct.

Q Would you expect that the Company -- one of the considerations that they have when they issue debt is to stagger the maturity of the various debt issuances so that they do not all mature at the same time?

A Yes, that would be a reasonable thing for them to do.

Q And did you take that into account when you recommended that the maturity be based on a 10-year rate?

A I looked at the maturing -- maturities going forward, but I didn't provide an exhibit that showed all the maturities that would be coming due over the next 10 to 20 years.

Q And in looking and performing that analysis, did you conclude that a maturity in 10 years would be a reasonable thing to do?

A No, actually what I -- what I advocated for, was a -- it was more -- it was standard; it wasn't saying you must issue it with a 10-year. It was, it was a few different years. It wasn't a point at

Exhibit 2022

Morgan Deposition
Pages:
32, 35, 52, 55

you assemble your sample group of companies?
A I did not; I omitted that.
Q Is there a reason you omitted that?
A There is no reason I omitted it.
Q Are there any other criteria that you apply that you did not mention in your testimony?
A Not that I can think of, no.
Q How about the regulatory regime that a utility operates under? For example, are the risks different for a T&D-only company than for a fully-integrated electric utility?
A When you say "risks," could you define what risks you're referring to?
Q Do you believe that the required rate of return is the same for a -- all other things being equal -- for a utility that's a T&D-only company versus a fully-integrated electric utility?
A I don't think I have a specific opinion on that.
Q Do you think that a vertically-integrated electric utility generally has the same risk profile as a T&D-only company?
A I think that the risk profile is likely different. How that might factor into cost of capital, I think it could vary.

with a power cost recovery mechanism be more or less risk than a utility without a power cost recovery mechanism?

A Are we assuming utilities that have a large amount of exposure to the market? Or -- I don't know if I could answer that question.

Q How about whether or not a utility is subject to a consolidated tax adjustment for ratemaking purposes in the various jurisdictions in which they operate? Is that something that you would take my account?

A When I made my sample selection I did not take that into account.

Q So you're not aware whether any of the utilities in your sample group are subject to a consolidated tax adjustment?

A No.

Q How about reliance on the wholesale market or a percentage of power supply for purchased power? Is that a relevant consideration?

A On --

Q In term determining your sample group of companies.

A It was not.

Q Do you know what the percentage of power

Q Have you considered the impact of the implementation of SB 408 on the volatility of a utility's earnings?
A No.
Q Are you familiar with the double whammy situation referred to in AR 499?
A I do not know what a double whammy is.
Q After you compiled your sample group of companies and performed your DCF calculations, did you consider whether or not any adjustment was necessary in the case of PGE to take into account its greater reliance on hydrogeneration?
MS. ANDRUS: Objection; ambiguous. Greater as opposed to what?
MR. VAN NOSTRAND: The sample group.
MS. ANDRUS: Objection; assumes a fact not in evidence that PGE has a greater reliance on hydro than the sample group.
BY MR. VAN NOSTRAND:
Q Can you answer the question?
A Could you restate your question?
Q Do you know whether or not -- did you look at the percentage reliance of hydrogeneration of any companies in the sample group?
A No, I did not. I did not look at the

A I'm familiar with what imputed debt is.

Q Do you understand that S&P considers purchased power agreements to be debt equivalents?

A Generally, yes.

Q And is the effect of S&P's treatment of debt equivalents to require greater amounts of equity in the capital structure to offset the impact of purchased power agreements?

A I'm not familiar with that.

Q Did they do a calculation which suggests a higher amount of equity capital to offset the debt equivalent associated with purchased power?

A I'm not familiar with S&P requiring a higher amount of equity in a capital structure. Because of debt imputation.

Q Do your knowledge, does S&P perform such a calculation in the case of PGE?

A I'm familiar that it does in that it's updating its overall framework right now, yes. For all companies. But I do understand that it also applies it to PGE.

MS. ANDRUS: Do both of you need to speak up for the court reporter? It's just me? I just have the bad hearing? Okay, sorry.

THE REPORTER: I've got this (indicating

PGE Exhibit 2023

- Staff stated in Staff Exhibit 1000, page 24 that "there is a lot of **evidence** that risk premiums may be time-varying." Staff's answer to the data request requesting such evidence was that it was "Mr. Morgan's **knowledge** and was not based on contemporaneous analysis of the literature." (OPUC Response to PGE Data Request No. 23[1]).
- Staff states at Staff Exhibit 1000, page 24 that he relies upon "**published** risk premium literature" to aid in his criticism of PGE's risk premium model. When asked for such "published literature," Staff did not provide it and again asserted that their testimony was based on **judgment** (OPUC Response to Staff Data Request No.'s 38 and 23).
- Staff states at Staff Exhibit 1003, page 35 that "Oregon has provided a favorable regulatory environment." When asked to provide the **evidence** for this statement, Staff stated that it "does not have the requested reports" and that "Staff is aware that S&P, Value Line and Regulatory Research Associates…considers Oregon's regulatory treatment to be favorable (OPUC Response to PGE Data Request No. 42).
- Staff states at Staff Exhibit 1003, page 4 that "…**most analysts** do not expect significant upward pressure." However, in response to PGE Data Request No. 053, when asked what is meant by "most analysts" and to provide **evidence**, Staff stated "Staff is referring to **its perception** of the current interest rate environment."
- Staff states at Staff Exhibit 1003, page 28 that "Although some **published literature** provides the arithmetic average, for ratemaking purposes, the compounded, or geometric average, return is the proper metric upon which to focus for cost of capital

determinations." In response to PGE Data Request No. 065, Staff stated that they are "**not aware of specific published literature** upon which the statement was based."

[1] OPUC Responses to PGE Data Requests are PGE Exhibit &&

			Moody's Index for:		**Above (Below)**	
Month/Year	**Issue**	**Effective All-In Debt Rate**	**Aa**	**Baa**	**Aa**	**Baa**
October 2002	FMB 8.125%	8.421%	7.07%	8.00%	135	42
October 2002	FMB 5.6675%	7.420%	7.07%	8.00%	35	(58)
April 2003	FMB 5.279%	6.434%	6.47%	6.94%	(4)	(51)
August 2003	FMB 5.625%	6.266%	6.48%	7.08%	(21)	(81)
August 2003	FMB 6.750%	7.220%	6.48%	7.08%	74	14
August 2003	FMB 6.875%	7.282%	6.48%	7.08%	80	20

			S&P's Index for:		**Above (Below)**	
Month/Year	**Issue**	**Effective All-In Debt Rate**	**A**	**BBB**	**A**	**BBB**
October 2002	FMB 8.125%	8.421%	7.01%	8.62%	141	(20)
October 2002	FMB 5.6675%	7.420%	7.01%	8.62%	41	(120)
April 2003	FMB 5.279%	6.434%	5.71%	6.82%	72	(39)
August 2003	FMB 5.625%	6.266%	6.06%	6.74%	21	(47)
August 2003	FMB 6.750%	7.220%	6.06%	6.74%	116	48
August 2003	FMB 6.875%	7.282%	6.06%	6.74%	122	54

S&P/Moody's Combined

	Company Name	Included / reason for exclusion
AYE	Allegheny Energy	No dividends paid since 12/31/2002
AEE	Ameren Corporation	Included
AEP	American Electric Power	Included
CEG	Constellation Energy Group	Merger in progress with FPL
CHG	CH Energy Group	Included
CNP	CenterPoint Energy	Included
CIN	CINergy Corp.	Completed merger with Duke Energy 4/3/2006
ED	Consolidated Edison	Included
DPL	DPL Inc	Dividend suspension within last three years (3/30/2004)
D	Dominion Res Inc VA New	Included
DTE	DTE Energy Co.	Included
DUK	Duke Energy Corp	Included
EAS	Energy East Corp	Included
EIX	Edison Int'l	Dividends suspended and reinstated within last three years
ETR	Entergy Corp.	Included; No data from 10/2005 - 1/2006
EXC	Exelon Corp.	Merger in progress with PSEG
FE	FirstEnergy Corp.	Included
FPL	FPL Group	Merger in progress with Constellation
IDA	Idacorp	Dividend reduction within last three years (12/31/2003)
IPL	Ipalco Enterprises	Acquired by AES
NI	Nisource	Dividend reduction within last three years (12/31/2003)
OGE	OGE Energy Corp	Included
PCG	PG&E Corp.	Dividends suspended since March 2001; reinstated 6/30/2005
PEG	Public Service Enterprise Group	Merger in progress with Exelon
PNW	Pinnacle West Capital	Included
POM	Potomac Electric Power Co	Included
PPL	PPL Corp.	Included
PGN	Progress Energy, Inc.	Included
SO	Southern Co.	Included
TE	TECO Energy	Included
TXU	TXU Corp.	Included
XEL	Xcel Energy Inc	Included
	Total Companies: 32	Included: 20

PGE Comparables

	Company Name	Included / reason for exclusion
LNT	Alliant	Included
AVA	Avista	Included
CNL	CLECO	Included
DPL	D P L Inc.	Dividend suspension within last three years
IDA	Idaho Power Co.	Dividend reduction within last three years (12/31/2003)
NU	Northeast Utilities	Included
NOR	Northwestern Corp.	No longer followed by Value Line
OGE	Oklahoma Gas & Electric Co.	Included
POM	Potomac Electric Power Co.	Included
PNW	Pinnacle West Capital Corp.	Included
PSD	Puget Sound Energy	Included
UNS	UniSource Energy Corp.(Tucson Electric Power Co.)	Included
WR	Western Resources	Included
WEC	Wisconsin Energy Corp.	Included
	Total Companies: 14	Included: 11

UE 170 Rebuttal Sample

	Company Name	Included / reason for exclusion
LNT	Alliant	Included
AEE	Ameren Corporation	Included
CHG	CH Energy	Included
CNL	CLECO	Included
ED	Consolidated Edison Co. NY Inc.	Included
EDE	Empire District Electric Co.	Included
EAS	Energy East Corp.	Included
ETR	Entergy Corp	Included; NOTE: No data for 10/2005 through 1/2006
EXC	Exelon Corp.	Merger in progress with PSEG
FPL	F P L Group Inc.	Merger in progress with Constellation
MGEE	MGE Energy	Included
NST	NSTAR	Included
PGN	Progress Energy	Included
SCG	Scana Corp	Included
SO	Southern Company	Included
VVC	Vectren	Included
XEL	Xcel Energy Inc.	Included
	Total Companies: 17	Included: 14

Table of Contents

I. Introduction and Qualifications

Q. Please state your name and address.

A. My name is Thomas M. Zepp. My business address is Utility Resources, Inc., Suite 250, 1500 Liberty Street, S.E., Salem, Oregon 97302.

Q. What is your profession and background?

A. I am an economist and Vice President of Utility Resources, Inc., a consulting firm. I received my Ph.D. in Economics from the University of Florida. Prior to jointly establishing our consulting firm in 1985, I was a consultant at Zinder Companies from 1982-1985 and a senior economist on the staff of the Oregon Public Utility Commissioner between 1976 and 1982. While on the Staff of the OPUC, I presented testimony on the cost of capital and other issues. Prior to 1976, I taught econometrics, economics and business courses at the University of Florida, Central Michigan University and in the Joint Graduate Program at Armstrong State and Savannah State Colleges.

I have been deposed or testified on various topics before regulatory commissions, courts and legislative committees in twenty-two states, before two Canadian regulatory authorities and before four Federal agencies. In addition to cost of capital studies, I have testified as to incremental costs of energy and telecommunications services, values of utility properties, and appropriate rate designs.

Q. What cost of capital studies have you prepared before?

A. I have submitted studies or testified on cost of capital and other financial issues before the Interstate Commerce Commission, Bonneville Power Administration, and courts or regulatory agencies in Alaska, Arizona, California, Hawaii, Idaho, Illinois, Kentucky, Montana, Nevada, New Mexico, Oregon, Tennessee, Utah, Washington and Wyoming.

My studies and testimony have included consideration of the financial health and fair rates of return for General Telephone of the Northwest, Illinois Bell Telephone, Nevada Bell Telephone, Pacific Northwest Bell, US WEST, Anchorage Municipal Light & Power, Arizona Public Service Company, Commonwealth Edison, Idaho Power, Iowa-Illinois Gas and Electric, Pacific Power & Light, Portland General Electric, Puget Sound Power & Light, Cascade Natural Gas, Mountain Fuel Supply, Northern Illinois Gas, Northwest Natural Gas, Anchorage Water Utility, Anchorage Wastewater Utility, Arizona Water Company, Arizona American Water Company, California American Water Company, California Water Service, Chaparral City Water Company, Dominguez Water Company, Golden State Water Company, Hawaii American Water Company, Kentucky American Water Company, Mountain Water Company, New Mexico American Water Company, Oregon Water Company, Paradise Valley Water Company, Park Water Company, San Gabriel Valley Water Company, San Jose Water Company, Southern California Water Company, Suburban Water System, Tennessee American Water Company and Valencia Water Company. I have also prepared estimates of the appropriate rates of return for a number of hospitals on behalf of the Washington State Hospital Commission and U.S. railroads.

Q. Do you have other professional experience related to cost of capital issues?

A. Yes. My article, "Utility Stocks and the Size Effect - Revisited," was published in the *Quarterly Review of Economics and Finance*, Vol. 43, Issue 3, Autumn 2003, pp. 578-582. Also, I published an article "Water Utilities and Risk," *Water the Magazine of the National Association of Water Companies* Vol. 40, No. 1 Winter 1999 and was an invited speaker on the topic of risk of water utilities at the 57th Annual Western Conference of Public Utility Commissioners in June 1998. I presented a paper "Application of the Capital Asset Pricing Model in the Regulatory Setting" at the 47th Annual Southern Economic Association

Conference and published an article "On the Use of the CAPM in Public Utility Rate Cases: Comment," *Financial Management* Autumn 1978, pp. 52-56. I have been a journal referee for the *International Review of Economics* and *Finance and Financial Management*. While on the staff of the Oregon PUC, I also established a sample of over 500,000 observations of common stock returns and measures of risk and conducted a number of studies related to the use of various methods to estimate costs of equity for utilities. I was invited to Stanford University to discuss that research.

II. Purpose and Summary of Testimony

Q. What is the subject of your testimony in this proceeding?

A. Portland General Electric Company ("PGE," or "the Company") asked me to review the Cost of Capital testimony of Thomas D. Morgan marked as Staff Exhibits 1000, 1002 and 1003, dated August 14, 2006, and respond where I thought it was appropriate.

Q. Have you prepared any tables to accompany your testimony?

A. Yes. I prepared and am sponsoring 10 exhibits.

Q. Please summarize your testimony.

A. I provide my testimony in three sections. In section III, I present five observations about Mr. Morgan's testimony to put his recommended ROE of 9.3% in perspective. All of those observations indicate 9.3% is substantially below PGE's cost of equity.

In section IV, I comment about Mr. Morgan's DCF analyses.

- I re-run his 40-year DCF analysis for his electric utilities sample with alternative assumptions Mr. Morgan said should be considered but he did not incorporate in his analyses, and find the internal rate of return for the DCF approach is 10.50%.
- I show that DCF estimates for utilities in another industry support PGE's requested ROE of 10.75%.
- I point out that if the difference in market leverage relied upon by investors when they buy utility stocks and book equity relied upon by regulators is recognized when authorized ROEs are determined, PGE would require a higher ROE than is indicated by the DCF method.

In section V, I explain why studies I have done and decisions of another commission support reliance on the risk positioning approach adopted by PGE. I also present two other risk premium equity cost analyses for electric utilities which indicate PGE has a cost of equity in excess of its requested 10.75%.

Q. What are your conclusions regarding PGE's cost of equity?

A. I conclude PGE's requested ROE of 10.75% is very conservative and should be adopted.

III. Overview of Mr. Morgan's Testimony

Q. What rates of return on equity and capital structures have PGE and Mr. Morgan recommended?

A. In PGE Exhibit 1100, filed March 15, 2006, Patrick Hager and William Valach recommended a rate of return on equity ("ROE") of 10.75% with a capital structure containing 55.96% common equity, 0.29% preferred stock and 43.75% long-term debt be used to determine PGE's revenue requirements in UE 180. That proposal assumes the NVPC regulatory framework proposed by Ms. Lesh and Mr. Niman (PGE Exhibit 400) is adopted.

Mr. Morgan (Staff Exhibit 1000) recommends an ROE of 9.3% with a capital structure that includes 48.5% common equity and 51.50% long-term debt. It is not clear whether this proposal considers at all the NVPC regulatory framework Staff supports in Staff Exhibit 800.

As another point of reference, ICNU-CUB witness Gorman recommends an equity return of 9.9% and an equity ratio of 50.0%.

Q. Do you have any general observations that put Mr. Morgan's recommended ROE in perspective?

A. Yes. I have five general observations.

- First, PGE is more risky than the sample of electric utilities Mr. Morgan chose to determine benchmark cost of equity estimates. Mr. Morgan does not adjust upward his ROE estimates for his sample of electric utilities to account for PGE's greater risk.

- Second, a 9.3% ROE recommendation is only 210 basis points higher than a consensus of analysts' forecasts of investment grade ("Baa") bond rates for the second quarter of 2007 (Blue Chip Financial Forecasts, August 2006). When compared to past data, this is a very low premium above investment grade bond rates.
- Third, since 2003 when the Public Utility Commission of Oregon ("Commission") determined that an appropriate ROE for NW Natural in UG 152 was 10.2%, interest rates and the costs of equity for all utilities have increased.
- Fourth, Mr. Morgan's recommendation is 180 and 150 basis points lower than averages of currently authorized and earned ROEs, respectively, for the sample of electric utilities that Mr. Morgan states recommends be used as guideline companies to determine a fair ROE for PGE.
- Fifth, there is a wealth of information available to determine benchmark equity costs that Mr. Morgan has chosen to exclude from his analysis. That information indicates PGE's cost of equity is much higher than 9.3%.

A. Rebuttal to Staff's ROE Recommendation

1. PGE is more risky than Staff's sample companies

Q. Is PGE more risky than the sample of electric utilities Mr. Morgan relies upon to determine PGE's recommended ROE?

A. Yes. PGE Exhibit 2101 compares five different measures of risk for PGE to comparable measures of risk for Mr. Morgan's sample of electric utilities.

Standard & Poor's Rating Services assigns "business profiles" to reflect the relative business risks of utilities. These business profiles range between 1 for the least risky company to 10 for the most risky companies. (*See* Staff/1003, Morgan 113). Based on those S&P rankings of risk, PGE (with a business profile of 5) is more risky than the average utility in Mr. Morgan's sample (with a business profile of 3.9).

PGE is also more risky than the Morgan sample based on considerations of bond ratings and percentages of purchased power. The data provided in Staff Exhibit 1003, page 124 report a bond rating for PGE of "BBB+" while the Morgan sample has a higher average bond rating of "A."

PGE is also more risky than the Morgan sample because PGE's percentage of purchased power of 49% is higher and thus PGE is more risky than the sample which has an average percentage of purchased power of 35%. PGE is publicly traded but not followed by Value Line and thus there are no beta estimates or Safety Ranks to compare to Mr. Morgan's sample.

Q. Do you have similar concerns with respect to Mr. Morgan's use of his sample of electric companies to determine PGE's capital structure in this proceeding?

A. Yes. PGE discusses the fact that bond rating agencies impute debt to PGE because of its purchased power contracts. During his deposition, Mr. Morgan acknowledged that S&P does indeed impute debt to companies with such purchased power contracts, but he was unwilling to incorporate that fact in his analysis of an appropriate capital structure for PGE. Instead, he went the other way and imputed a hypothetical capital structure to PGE for ratemaking which is even more leveraged.

I have a simple observation. It is that based on the three available measures of risk, even though PGE has a "higher" equity ratio than the Morgan sample, it is more risky than

Mr. Morgan's sample. Even without consideration of imputed debt, with a business profile of 5, S&P has a higher (not lower) target equity ratio for PGE to obtain the same bond rating as an average utility in Mr. Morgan's sample, with a business profile of 3.9. The full story must recognize that PGE has imputed debt and higher than average business risks which should be offset with the risk-reducing benefit of lower leverage. Mr. Morgan fails to adjust the guideline estimates of costs of equity he obtains for his sample to recognize PGE is more risky.

Q. Does PGE have other risks not reflected in PGE Exhibit 2101?

A. Yes. In the testimony of Mr. Hager and Mr. Valach, PGE discusses a number of risks that are beyond the control of the Company and the Commission. For example, added risk was imposed by the legislature when it passed SB 408. In January, Regulatory Research Associates downgraded the regulatory environment in Oregon as a result of that legislation. When the Commission determines a fair ROE for PGE, the added risk of SB 408 and other company-specific risks discussed by PGE should be considered.

2. Staff's recommended ROE is extremely low

Q. Why is Staff's recommendation unreasonable?

A. A 210 basis point risk premium above the cost of investment grade bonds is extremely small when compared to premiums found reasonable by this commission in past cases. In UG 152, for example, the premium found reasonable by the Commission was 344 basis points above the average 2003 "Baa" rate of 6.76%. Data in PGE Exhibit 2101 show PGE is more risky than NW Natural and thus the 344 basis point risk premium provides a conservative measure of the premium now required by PGE. A 210 basis point risk premium is also very conservative when compared to risk premiums produced with various studies I discuss later in my testimony.

3. Interest rates are rising

Q. Have costs of equity increased since 2003 when the Commission determined NW Natural required an ROE of 10.2%?

A. Yes. Interest rates and costs of equity have increased since the Commission determined NW Natural required an ROE of 10.2% in UG 152. PGE Exhibit 2102 computes the indicated increase in the cost of 7-year Treasury security rates between July 2003 (when Staff prepared Surrebuttal testimony in UG 152) and November 2003 (when the Commission issued its order in UG 152) and August 29, 2006. During the 2003 period indicated, the average monthly rates on 7-year Treasury securities ranged from 3.45% to 3.96%; thus, rates for 7-year Treasury securities have increased by 81 to 132 basis points since the 10.2% ROE was found reasonable for NW Natural.

PGE Exhibit 2102 also computes the indicated increase in the cost of equity. PGE's risk positioning model reported at PGE Exhibit 1110, page 1 reports equity costs will tend to increase by 55 (1-.4477) basis points to 57 (1-.4262) basis points for every 100 basis point increase in the rates on 7-year Treasury securities. The PGE estimates are validated by a determination by the California PUC in multiple dockets that costs of equity for energy utilities increase by one-half to two-thirds of the change in a benchmark interest rate. (Table 3 of California PUC Decision 97-12-089 confirmed in California PUC Decision 02-11-027) PGE's estimates are also in line with studies I have conducted in the past for gas utilities and water utilities and a study conducted by Oregon PUC Staff in Docket UT 85 that found risk premiums vary inversely with interest rates (*See* UT 85, Staff/3, January 20, 1989). Based on the increases in 7-year Treasury security rates and the PGE study, the indicated increase in the cost of equity since the Commission determined a 10.2% ROE was reasonable for NW Natural falls in a range of 10.66% to 10.95%. Based on the measures of risk reported in

PGE Exhibit 2101, NW Natural is less risky than Mr. Morgan's sample of electric utilities and PGE, and thus a range of 10.66% to 10.95% is a conservative estimate of PGE's current cost of equity.

4. Mr. Morgan's recommendation is lower than averages of currently authorized and earned ROEs for Mr. Morgan's sample

Q. Are earned and authorized ROEs for Mr. Morgan's sample important information that should be considered in the determination of a fair ROE for PGE?

A. Yes. The U. S. Supreme Court's decisions in the 1923 *Bluefield Waterworks* case and 1944 *Hope Natural Gas Company* case, as well as ORS 756.040, set forth three standards for a fair ROE.[1] In effect, the Oregon legislature and the U.S. Supreme Court require the Commission to determine rates and rate adjustment mechanisms for PGE that allow the Company to have a fair chance to earn its opportunity cost of capital, *i.e.*, returns investors could expect to earn if they invest in other enterprises of comparable risk. Mr. Morgan contends that those "other enterprises of comparable risk" are the utilities in his sample of 14 electric utilities. If that is the appropriate benchmark, PGE should be authorized rates and rate adjustment mechanisms that allow it a reasonable opportunity to earn a return on equity as high as investors can expect will be earned by his sample companies. If, as PGE Exhibit 2101 indicates, PGE is more risky than that sample, it should be authorized rates and rate adjustment mechanisms that give it an opportunity to earn an ROE higher than is expected to be earned by the sample.

The two obvious measures of the opportunity cost of equity that are available to investors are ROEs currently being earned and ROEs the utilities are authorized to earn. If

[1] Mr. Hager and Mr. Valach discuss these standards at UE 180/PGE Exhibit 1100 page/3-4. These standards were confirmed in the 1989 *Duquesne Light Co. v Barasch* case.

regulators authorize rates and rate adjustment mechanisms that allow utilities a reasonable chance to earn their costs of equity, an average of earned ROEs for the sample as well as an average of authorized ROEs provide measures of that opportunity cost of equity. PGE Exhibit 2103 provides a list of earned and authorized ROEs for the companies in Mr. Morgan's sample. In compiling this list I have used the smaller of ROEs reported by Value Line and AUS Utility Reports when the reported values differed. In cases where Value Line reported authorized ROEs for several jurisdictions, I used the average of authorized ROEs determined by AUS in the August 2006 AUS Utility Reports. Taking into account that PGE is more risky than companies in Mr. Morgan's sample, the evidence in PGE Exhibit 2103 indicates the opportunity cost of equity for investors in PGE stock is above the range of 10.8% to 11.1%.

Q. Does the evidence in PGE Exhibit 2103 depend upon what types of models were used to determine the ROEs or what assumptions were used to produce equity costs with those unknown models?

A. No, it does not. The evidence in PGE Exhibit 2103 provides a direct estimate of the opportunity cost of equity that the Oregon legislature and the U.S. Supreme Court have found should be considered in determining a fair rate of return on equity. Ultimately, the test of a fair ROE is not whether the correct assumptions are used to determine equity costs with the DCF model or some type of risk premium model. The ultimate test is whether the rates and rate adjustment mechanisms authorized for PGE by the Oregon Commission give PGE an opportunity to earn the rate of return investors could expect to earn if they invested in another utility of comparable risk. PGE Exhibit 2103 provides conservative evidence about what that range of ROEs is for PGE.

Q. Does Mr. Morgan rely upon the type of information you report in PGE Exhibit 2103 or any other information about ROEs investors expect his sample companies to earn when he determined his recommended ROE for PGE?

A. No, he does not. He limits his analysis to equity costs determined with three versions of the DCF model.

Q. What weight should the Commission give to the information in Exhibit 2103?

A. The Commission should consider all useful information when it determines a fair ROE for PGE. PGE Exhibit 2103 is a part of that information and should be given no less weight than equity costs determined with financial models such as the risk premium (or risk positioning) models and DCF models. All models require assumptions, and differences in equity cost estimates result when analysts select different models and assumptions. The information in PGE Exhibit 2103 is transparent and does not rely upon hidden assumptions. It requires only an assumption that the ROEs—be they authorized or earned—provide reasonable indications about ROEs investors expect those companies to earn in the future. I do not recommend limiting the Commission's inquiry to PGE Exhibit 2103 and recommend the DCF and risk premium approaches I present below also be considered. But, PGE Exhibit 2103 provides important perspective. If equity costs estimated with financial model(s) are significantly lower or higher than the ROEs tabulated in PGE Exhibit 2103, the Commission should question the assumptions that drive the results coming out of those models. In my view, the information in PGE Exhibit 2103 raises serious questions about the usefulness of whatever models and assumptions Mr. Morgan has used to justify an ROE that is 150 to 180 basis points lower than the currently earned and authorized ROEs for utilities Mr. Morgan says are of risk comparable to PGE.

5. Mr. Morgan did not use readily available information

Q. Did Mr. Morgan consider other factors in his analysis?

A. There is a wealth of information that the Commission should consider when determining a fair ROE for PGE that Mr. Morgan has ignored. That information includes: 1) DCF estimates for samples of other types of utilities, 2) the sensitivity of Mr. Morgan's 40-year DCF model to different assumptions about growth Mr. Morgan says should be considered in a DCF analysis but he does not consider, 3) an analysis that explains why results of DCF models are expected to understate ROEs required in jurisdictions that rely on original cost rate bases, 4) the risk positioning models presented by PGE, and 5) two risk premium models I present in Section V.

IV. Response to Mr. Morgan's DCF Estimates

Q. At Staff Exhibit 1000, page 2, Mr. Morgan tells the Commission he has produced a table of ROE results that provide the Commission with information related to the upper and lower ends of a reasonable cost of equity estimate for PGE. Do you agree?

A. No, I do not. As I will explain further below, I disagree because Mr. Morgan has excluded a large amount of useful information by relying solely on the DCF model for his sample of 14 electric utilities to determine his equity cost estimates. Also, if investors do rely on the DCF model, Mr. Morgan does not consider all of the assumptions investors might reasonably consider when they price electric utility stocks with such a model. That said, I provide three primary responses to his DCF analyses.

First, I discuss growth rates that should be used in the determination of DCF equity cost estimates for electric utilities. I note that Mr. Morgan has omitted a portion of sustainable growth and explain why analysts' forecasts of growth may understate growth expected by investors. I show analysts' forecasts for utilities in another industry produce more reasonable equity cost estimates.

Second, I re-run Mr. Morgan's 40-year DCF analysis for his electric utility sample with three changes. Those changes are:

a) When estimating sustainable growth, I include growth that results when common shares are sold at prices in excess of book value, called "sv" growth. This component of sustainable growth was routinely included in DCF estimates by the Oregon Staff in past cases, but is excluded by Mr. Morgan;

b) I rely upon—as Mr. Morgan says we should do—historical information to determine growth investors expect in the first stage of the model; and

c) Once the second stage is reached, I assume the retention ratio attained in the first stage continues and the expected ROE for the sample is 12.5%, the ROE Value Line projects for the electric utility industry. This 12.5% is the ROE that Mr. Morgan says should be considered (Staff Exhibit 1000, page 13) but he did not consider in his analysis. The 12.5% ROE is a forecasted return on year-end equity; in computing "br" growth (ROE times the company's retention ratio), I adjust the growth rate estimate with the FERC formula to put the "r" in "br" growth on a mid-period basis.

Third, I address a general problem with DCF estimates, which several prestigious ROE analysts have argued means, that unadjusted DCF estimates understate the ROE required in regulatory jurisdictions that rely on original cost as the measure of rate base and capital structure for ratemaking.

A. DCF Model

1. General comments on the DCF model

Q. Do you have any general comments about the DCF model?

A. Yes. Conceptually, investors use the valuation model in equation 1) to determine how much they are willing to pay for stocks:

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

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. Presumably, if the market price for the stock were less than P_{buy} and the investor had the funds, he/she would buy the stock. In his 1974 book, Myron

Gordon (M. J. Gordon, The *Cost of Capital to a Public Utility*, Michigan State University, East Lansing, Michigan, 1974) made a number of assumptions[2] and adapted equation (1) to derive equity cost estimates with the DCF model. After making assumptions about the pattern of future cash flows and market efficiency and rearranging terms, what was previously an input (the discount rate) in the determination of the value of a stock in equation (1) became the focus of the inquiry.

Q. Why is this background important?

A. It is important because it should be clear that all models—including the DCF model—are based on abstractions and simplifying assumptions. With the risk positioning and risk premium approaches presented by PGE and by me, those assumptions are fairly straight forward but are not generally the same as the assumptions being made with whatever version of the DCF model is being used. We do not know which assumptions best reflect investor motives when they buy and sell stocks; thus, it is important to look at more than one type of model. Given concerns with determining the growth rates investors expect for electric utilities, it is appropriate to examine DCF estimates for other types of utilities as well as consider other types of models and the information in PGE Exhibit 2103.

2. Mr. Morgan's DCF analysis

Q. At lines 8-14 of Staff Exhibit 1000, page 7, Mr. Morgan outlines the three types of growth rates he considered. Do you have any comments about this testimony?

A. Yes. I address each of his categories of growth rates below. I summarize my comments here.

[2] Some of those assumptions are prices for stocks are efficient, investors have an infinite time horizon and investors are price takers and thus cannot affect stock prices.

1. Analyst's Forecasts. I have examined analysts' forecasts for electric utilities reported by Mr. Morgan (Staff Exhibit 1002, page 16) and Mr. Gorman (ICNU Exhibit 305, page 1) for their samples. It appears these financial analysts are making conservative forecasts for at least three reasons.

2. Sustainable growth. Below I explain that sustainable growth should be computed as the sum of growth from retained earnings (called "br" growth) and sales of stock above book value (called "sv" growth). Oregon PUC Staff routinely included "sv" growth in cases in which I testified in the past, but Mr. Morgan has excluded (with no explanation) "sv" growth from his sustainable growth calculations. Based on data in Mr. Morgan's exhibits, "sv" growth for his sample is expected to be 0.47%. In effect, Mr. Morgan has excluded almost 50 basis points of growth from all of his estimates of sustainable growth. Just fixing this obvious flaw would increase his recommended ROE from 9.3% to 9.8%.

3. Historical Utility Growth rates. Mr. Morgan recommends that past growth be considered by the Commission but he does not include estimates of such past growth in his DCF models. I do. Below, I modify his 40-year three-stage model and show that: a) if investors relied upon past growth in earnings per share ("EPS") when they formed their expectations of cash flows considered in equation (1); b) expected "sv" growth is included in the analysis; c) the First Stage is modified to be 10 years in length; d) growth of dividends per share ("DPS") in the First Stage is the same as was assumed by Mr. Morgan; and e) investors expect to earn Value Line's forecast of the future ROE of 12.5% instead of Mr. Morgan's 12%, but all other assumptions made by Mr. Morgan are unchanged, the derived internal rate of return for Mr. Morgan's 40-year DCF analysis increases to 10.50%.

3. Analyst forecast growth estimates

Q. Please turn to your comments about analysts' forecasts of growth.

A. It is a difficult task to find a sample of electric utilities that does not have several companies that have cut dividends in the last 10 years, merged with other utilities, or had volatile earnings per share. With such an unstable past, investors do not have a firm foundation to establish their predictions for the future. Mr. Morgan's sample of electric utilities is no exception. During the last 10 years, five of the 14 utilities in Mr. Morgan's sample cut dividends, one-half of the sample companies had earnings that were more volatile than the S&P 500 index, and three of those utilities were in mergers. I expect this past volatile environment and uncertainties about future costs to generate power have had three impacts on analysts' forecasts.

First, analysts appear to recognize the extremely volatile period this industry went through in the last 10 years and are justifiably cautious about forecasting realistic earnings per share growth rates.

Second, it may be that the financial analysts are generally pessimistic about prospects for the electric utility industry.

Third, a number of electric utilities have merged during the last 10 years and investors may expect more mergers in the future. Such mergers provide economies of scale and synergies that enhance future cash flows to levels higher than would be expected from simple growth in EPS. When investors use equation (1) to determine prices they are willing to pay for electric utilities' stocks, they would include something in those future cash flows to reflect the probability of more mergers and higher cash flows than would be obtained by simply looking at EPS growth. Analysts' forecasts of EPS growth do not address such potential higher cash flows from such mergers. If financial analysts are either cautious or pessimistic about the prospects for all electric utility companies—not just Mr. Morgan's sample of companies—it is not unreasonable to expect analysts are not forecasting EPS growth to be as rapid as investors expect. In addition, if future mergers occur, as they have in the past, future cash flows will be enhanced and analysts' forecasts of EPS growth will not capture all future cash flows investors anticipate when they price stocks.

Q. Have you recently conducted a DCF analysis for utilities in another industry in which analysts do not appear to have such concerns?

A. Yes. In that DCF analysis, I adopted a sample of six water utilities that have at least 80% of their revenues from regulated water operations and have at least one analyst's forecast of 5-year EPS growth.[3] The result of that analysis is provided in PGE Exhibit 2104. Combining average dividend yields for utilities in that sample with an average of analysts' forecasts of growth provided by Zacks, First Call and the S&P Earnings Guide, the indicated cost of equity made with analysts' forecasts is 10.82%.

Q. What do you conclude about the use of analysts' forecasts of growth to determine equity costs for electric utilities?

A. Given the very low ROE estimates made with analysts' forecasts of growth for electric utilities, it appears that analysts are being cautious or pessimistic about companies in this industry and may not include other future cash flows expected by investors.

<u>4. Mr. Morgan did not include "sv" growth in his estimates</u>

Q. Your second point relates to Mr. Morgan's estimates of sustainable growth. Should Mr. Morgan include "sv" growth in his estimates of sustainable growth?

A. Yes. Myron Gordon is generally regarded as the "father" of the DCF model used in regulatory proceedings. In Gordon's model, sustainable growth is computed as the sum of expected growth from future retained earnings ("br" growth) and expected future growth from sales of common stock above book value (called "sv" growth). Mr. Morgan left out one of the components of sustainable growth.

Q. Does the Federal Energy Regulatory Commission (FERC) include estimates of "sv" growth in estimates of sustainable growth?

A. Yes. FERC stated:

> "g" is the sustainable growth rate of DPS . . . [where] the sustainable growth rate is calculated by the following formula: g = br + sv, where "b" is the expected retention ratio, "r" is the expected earned return on common equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate. (*Southern California Edison* referring to note 37 to *Connecticut Light and Power Co.* 45 FERC P 61370 at page 62,161 n 13 (1988)).

Q. In Oregon PUC cases in which you testified in the past, did the Oregon PUC Staff routinely include "sv" growth as part of its estimates of sustainable growth?

A. Yes. See, for example, Staff testimony in UG 132, Staff Exhibit 1600 dated July 2, 1999.

Q. At Staff Exhibit 1000, page 1113, Mr. Morgan discusses sustainable growth. Does he explain why he has excluded "sv" growth?

A. No.

Q. Did Mr. Morgan have the data to compute "sv" growth?

A. Yes. In Staff Exhibit 1002, page 11, Mr. Morgan provides estimates of past and projected increases in the number of shares for each of the companies in his sample. His data can be used to estimate a forward-looking estimate of the increase in the average number of shares ("s") of 1.1% per year for his sample. Mr. Morgan also relies on a market to book ratio of 1.73 in his 40-year DCF analysis. Using that market to book ratio, the indicated estimate of "v" is .42 = (1- (Book value/Market value)) and the indicated missing component of

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[3] With these criteria, Pennichuck Corporation would also be included in the sample. If it were included, based on available current data, the equity cost estimate would increase. Pennichuck is, however, under threat of

sustainable growth is 0.47%. In effect, by leaving out "sv" growth, Mr. Morgan has biased downward all of his estimates of sustainable growth by approximately 50 basis points.

Q. Turning to your third point, at Staff Exhibit 1000, page 7, Mr. Morgan states he considered historical utility growth rates. Were you able to determine how he incorporated historical utility growth rates in his analyses?

A. No.

Q. Have you revised Mr. Morgan's 40-year DCF analysis to assume investors consider past historical growth in EPS to forecast future growth in EPS?

A. Yes, I have. I have made three changes to Mr. Morgan's 40-year DCF analysis (Staff Exhibit 1002, page 6). The primary change is I have assumed that marginal investors consider past growth in EPS during the last 10 years to forecast future EPS growth in the next 10 years. At Staff Exhibit 1003 page 43, Mr. Morgan reports 40% to 60% of the shares of companies in his sample are owned by institutional investors. These institutions may conduct their own analyses of future prospects for electric utilities and give little or no weight to analysts' forecasts of future EPS growth reported by the financial press. I do not, however, assume any change in DPS growth Mr. Morgan used to determine growth in his First Stage.

Second, I have included "sv" growth in the analysis. Mr. Morgan did not include it.

Third, I have assumed investors expect electric utilities will earn an ROE of 12.5% during the second stage of the analysis. This is Value Line's forecast of the return on year-end equity that will be earned by the electric utilities industry during 2009-2011. At Staff Exhibit 1003, page 96, Staff Exhibit 1003, page 97, and Staff Exhibit 1003, page 98, this Value Line forecast was reported but not used in Mr. Morgan's analysis. At Staff

condemnation by the City of Nashua and is not included.

Exhibit 1000, page 13, Mr. Morgan says it is reasonable to assume investors rely upon "the future expectations for the specific industry" in Stage 2 which is the 12.5% forecast reported by Value Line and used in my restatement of his 40-year analysis. I have adjusted the "br" growth rates made with the 12.5% forecasted ROE with the FERC formula to put the ROE in "br" growth on a mid-period basis. Mr. Morgan's analysis in the first stage of his 40-year analysis is based on returns on average equity, and during his deposition, Mr. Morgan stated his 12% forecast for the Second Stage was also intended to be a return on average equity.

Q. Do you have any other comments about the changes you made to restate Mr. Morgan's 40-year DCF analysis?

A. Yes. At numerous places, Mr. Morgan advises the Commission it should consider historic utility growth rates in a DCF analysis. I revised the first stage of his 40-year DCF analysis by making the assumption that investors do rely on past growth in EPS and assume the same changes in EPS that occurred in the last 10 years will occur in the next 10 years. I also revised the length of Stage 1 to accommodate that assumption. I do not however, change Mr. Morgan's assumption about growth in DPS in the First Stage. I still assume, as does Mr. Morgan, that DPS will grow at 3% per year in the First Stage and adopt all of Mr. Morgan's initial numbers for 2005 and 2006 for his sample.

Q. Should the Commission include expected growth in book value from sales of stock above book value in a restatement of Mr. Morgan's 40-year DCF analysis?

A. Yes.

Q. What are the results of your restatement of Staff Exhibit 1002, page 6?

A. The results are reported in PGE Exhibit 2105. With this change in the assumption about EPS growth expected by investors in the First Stage, the expected retention ratio increases to 54.5% by 2015. After 2015, consistent with Mr. Morgan's approach, I assume the level of the retention ratio is stable and maintained for the rest of the years in the analysis. With these three changes, the indicated internal rate of return for the 40-year analysis for his electric utility sample is 10.50%.

Q. Why does your analysis indicate Mr. Morgan's sample has a required ROE that is so much higher than Mr. Morgan computed with his analysis?

A. The primary reason is that my analysis computes the retention ratio for the second stage instead of assuming it will be 40%. My first stage is 10 years long. I have assumed that DPS will grow at the same rate that Mr. Morgan assumed will occur in his first stage, but I assume investors expect future EPS growth during the next 10 years will be the same as it was in the last 10 years. With my assumption, EPS grows faster than DPS and the retention ratio increases to 54.5%. My analysis also produces a higher ROE because I have included "sv" growth and have assumed investors expect his sample of electric utilities will earn the ROE Value Line projects will be earned in the future by the electric utility industry.

Q. Are there any factors that make your analysis conservative?

A. Yes. To the extent that investors expect Mr. Morgan's sample companies to benefit from future merger activity, I have understated the required ROE. Cost-effective future mergers would cut costs due to synergies and economies of scale and thus would increase future cash flows.

Q. You changed the length of the first stage. What is the internal rate of return using the 40-year DCF analysis if you ended the first stage in 2010 but assumed investors expected past growth in EPS during the most recent five year period will occur in the first stage?

A. The analysis would produce an internal rate of return of 10.31%. See PGE Exhibit 2106. The internal rate of return drops primarily because the Stage 2 retention ratio increases to only 47.3% by 2010. In effect, this sensitivity analysis shows that if investors expect EPS to be growing more rapidly than DPS in the First Stage, the internal rate of return will increase if the First Stage is assumed to be longer than 5 years.

Q. What is the most important point of the analyses you have presented in PGE Exhibits 2105 and 2106?

A. The most important point is that if investors give weight to actual past earnings growth, investors may expect much higher growth in future cash flows than has been assumed by Mr. Morgan. We do not know what cash flows investors expect to receive from electric utility stocks. If they expect the pattern of past EPS to repeat itself in the future, the indicated cost of equity range of 10.31% to 10.50% is just slightly below PGE's requested ROE of 10.75%.

At a minimum, this analysis shows the Commission Mr. Morgan has not provided a realistic "Range of Results" in his table at Staff Exhibit 1000, page 2. At Staff Exhibit 1000, page 7, Mr. Morgan states that historical utility growth rates should be considered in a DCF analysis. PGE Exhibits 2105 and 2106 consider such past growth and find that if investors give weight to actual past EPS growth for his sample of electric utilities, the appropriate "Range of Results" at Staff Exhibit 1000, page 2 should report an ROE range of 8.5% to 10.5%. Further, if other useful indicators of the cost of equity are considered, the range would include equity costs at and above 11.0%. Contrary to Mr. Morgan's testimony, an appropriate DCF range includes the equity cost requested by PGE.

Q. Do you have any other concerns with the way Mr. Morgan applies the DCF model?

A. Yes. It is inappropriate to use spot prices to determine dividend yields for DCF estimates presented in regulatory proceedings for at least three reasons. First, there are no estimates of "spot" growth rates to combine with the estimates of spot prices. Value Line, for example, updates its growth rate forecasts every three months. Also, other investor services do not report daily updates of growth rate estimates. And to the extent that historical data are relied upon to estimate future growth rates, little if any new historical data are provided on a daily basis. The constraint on the quality of the equity cost estimate comes from the quality of the growth rate estimates, not easily measured dividends and prices. Spot yields provide a false sense of accuracy and should not be used to estimate DCF equity costs in regulatory proceedings.

Second, spot prices and spot dividend yields create arbitrary cost of equity estimates. A comparison of Mr. Morgan's testimony in this case and in the PacifiCorp case shows the primary driver for the 20 basis point difference in recommended ROEs in these cases is a difference in spot prices used in the analyses. Refer back to equation (1). The prices investors are willing to pay for stocks in Mr. Morgan's sample depend on expected cash flows and the discount rate being used to discount those cash flows. If indeed one believes markets are efficient, it is likely that changes in growth of the expected cash flows—that we do not know about—led to the changes in spot prices. If daily updates of the growth rates relied upon by investors buying and selling shares of stock are not available, daily updates of the prices simply produce arbitrary equity cost estimates. Average dividend yields are not a perfect answer, but produce equity costs that are generally consistent with the quality of the growth rate estimates that are available.

Third, it takes a huge leap of faith to actually believe markets are as extremely efficient as one has to believe when using spot prices. In my view it is nonsense to assume minute-by-minute changes, even day-by-day changes, in prices fully reflect all available information about the stock, the economy, the U. S. stock market, international stock markets and all of the other information that may affect the value of utility stocks. Use of average prices also presumes market efficiency, but allows for a period in which all of the relevant information that supposedly is reflected in stock prices is actually recognized by investors.

Q. Is there a general problem with DCF estimates of the cost of equity that Mr. Morgan does not address?

A. Yes. Lawrence Kolbe, the lead author of A. Lawrence Kolbe and James A Read, Jr. with George R. Hall, The Cost of Capital Estimating Rate of Return for Public Utilities, MIT Press, 1986 published an article in 2005 which addresses the mismatch of capital structure considered by investors when they buy utility stocks and the capital structure used in an original cost jurisdiction like Oregon. (A. Lawrence Kolbe, Michael J. Vilbert and Bente Villadsen, "Business & Money – Measuring Return on Equity Correctly" www.fortnightly.com/pubs/4572.cfm, August 2005). The argument is very simple and intuitive: investors buy common stocks at market prices above book values and thus the equity ratio of concern to them is higher than the more leveraged equity ratio used by regulators to set rates. For Mr. Morgan's sample, the book equity ratio (used in ratemaking) is 49% (Staff Exhibit 1002, page 9) and the market to book ratio is 1.73. (Staff Exhibit 1002, page 6). Based on simple arithmetic, these data imply the market capitalization ratios are 38% for debt and 62% for common equity (assuming no preferred stock and book costs of debt are the same as market values of debt to keep the analysis simple). Kolbe, et. al. report that the financial literature now concludes the required after-tax ROR does not change with differences in leverage for a reasonable range of equity ratios. Assuming a debt cost of 7% and an equity cost derived from market data of 10.25%, we have the following:

	Capitalization Ratio	**Cost**	**Weighted Cost**
Debt	38%	7.00%	2.78%
Equity	62%	10.25%	6.40%
Total			9.18%

Kolbe, *et. al.* say the embedded cost of debt (I have assumed is 7%) should be used in this analysis.

When regulators set rates, the original cost of book equity is used in the capital structure for ratemaking and indicated cost of equity increases to "K":

	Capitalization Ratio	**Cost**	**Weighted Cost**
Debt	51%	7.00%	3.77%
Equity	49%	K	5.41%
Total			9.18%

Solving for K, the indicated cost of equity for ratemaking purposes is 11.0%, not 10.25%.

Kolbe, Vilbert and Villadsen conclude:

> Differences between the market-value capital structures of the sample companies and the capital structure used to set rates can be large. If so, there will be equally large differences in the amount of financial risk—hence, the costs of equity at the different capital structures. Failure to take these differences into account is likely to lead to allowed rates of return on equity that are materially below the costs of equity that utility shareholders actually require. ("Business & Money – Measuring Return on Equity Correctly" www.fortnightly.com/pubs/4572.cfm, August 2005, page 3)

Q. Have you adjusted your DCF equity cost estimates to reflect this analysis?

A. No, I have not. I have presented it to explain why we should not be surprised if DCF models produce cost of equity estimates that are lower than equity costs indicated by other models, such as risk premium and risk positioning models. This article is also another reason for the Commission to consider more than the limited information about PGE's cost of equity that is suggested by Mr. Morgan's application of the DCF model.

Q. Do you have any responses to Mr. Morgan's comments about analysts' forecasts of growth in Staff Exhibit 1000 and Staff Exhibit 1003?

A. Yes. At Staff Exhibit 1000, page 10 and in Staff Exhibit 1003, page 319 and page 323, Mr. Morgan suggests analysts may expect growth to be higher than sustainable growth, provides an article in which the author concluded analysts provided inflated forecasts, and provides another article that found actual growth rates had been lower, on average than growth expected by analysts. I have three responses. First, I have already explained several reasons analysts' forecasts may understate—not overstate—growth expected by marginal investors buying and selling electric utility stocks. I do not repeat that testimony. Second, there is evidence that analysts' short-term forecasts understate growth that actually occurs. And third, at least for utilities, long-term forecasts made by analysts understate future growth that has actually occurred.

With respect to the second point, contrary to Mr. Morgan's suggestion, it is generally *not* true that analysts' projected EPS growth rates overstate growth in the short term. In an article posted 4/23/2004, *USA Today* stated more than half of the S&P 500 companies had reported earnings at that point in time and 78% of those companies beat analysts' estimates. The article also pointed out that *typically*, 58% of companies beat forecasts. If more than half of the companies typically beat earnings forecasts, a contention that analysts' projected EPS growth exceed actual growth—at least in short-term forecasts—is not true.

Q. What about the issue of bias in longer-term analysts' forecasts?

A. In Oregon PUC Docket UG 132, I conducted a test of the quality of Value Line forecasts of future ROEs and found that Value Line analysts' forecasts for utilities were actually lower than what the utilities earned in real terms. My study compared Value Line forecasts of returns for a sample of eight gas distribution utilities to realized returns for the same sample of eight gas distribution utilities during the 21 year period 1977 to 1998. I have reproduced the results of my study in PGE Exhibit 2107. The original study and the testimony that more completely explains that study are available to Mr. Morgan and the Commission in the OPUC files for UG 132. Value Line states it takes forecasts of inflation into account when it makes forecasts of earnings and future ROEs. In my study I took into account differences in Value Line's forecasts of inflation and the inflation that subsequently occurred and thus compared real forecasts of returns with realized real returns. I found that, after recognizing differences in actual and realized inflation, the average of Value Line forecasts of ROEs were 11 basis points *lower* than ROEs that were realized. 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. My study showed that, at least for utilities, the Value Line forecasts were not biased upward during a 21 year period.

V. Other Information and Other Models

Q. Does Mr. Morgan offer any evidence other than his DCF model estimates of the cost of equity to support reducing PGE's ROE to a level of 9.3%?

A. Yes. While he does not offer a risk premium model for electric utilities to support his ROE recommendation, at Staff Exhibit 1003, page 17 and other places Mr. Morgan presents results of studies that he asserts would support equity risk premiums that are lower today than in the past. I do not agree with his contention for at least four reasons.

First, contrary to the studies he presents, Value Line forecasts of risk premiums for its Industrial Composite have increased since 1986. See PGE Exhibit 2108. The Value Line composite is currently a composite of data for 635 industrial, retail and transportation companies.

Second, the theoretical work of Gordon and Halpern ("Bond Share Yield Spreads Under Uncertain Inflation," *American Economic Review*, 66: 4 (September-1976, pp. 559-565) explains why we should expect common stock risk premiums to vary inversely with inflation and interest rates. It is generally recognized that as inflationary expectations increase, investors will demand higher long-term interest rates to offset lost purchasing power.

Third, the results of studies I have done over the years for all types of utilities show equity costs are expected to move in the same direction as interest rates, but by less. Said another way, risk premiums vary inversely with interest rates. The risk positioning study PGE presented in this case and at least one study I can recall that was conducted by the Oregon PUC Staff in the past (in Docket UT 85) also found risk premiums vary inversely with interest rates. With lower interest rates and lower expected inflation, expected risk premiums increase, they don't decrease.

Fourth, Mr. Morgan refers to a 2002 paper by Roger Ibbotson and Peng Chen that he implies supports a current market risk premium that is lower than one based on an historical average of past returns. In Chapter 5 of the 2006 Ibbotson Associates *Valuation Edition of the SBBI Yearbook,* Ibbotson Associates put the Ibbotson and Chen analysis in perspective. At page 97, they state that contrary to several recent studies of equity risk premiums that declare equity risk premiums to be very small, Ibbotson and Chen found the long-term supply side estimate of the long-horizon equity risk premium to be only slightly lower than the straight historical average. At page 98, they also note that though some of the theories are compelling in an academic framework, most do little to prove the expected market risk premium based on historical data is too high.

Q. What other types of information should the Commission consider when determining a reasonable ROE for PGE?

A. I recommend the Commission consider the type of data in PGE Exhibit 2103 equity cost estimates for utilities in other industries and data provided by at least three other types' models. I have already explained why I recommend the Commission consider the data in PGE Exhibit 2103. Both authorized and realized ROEs provide direct evidence about the opportunity cost of capital that should be the basis for PGE's authorized ROE, under the standards of ORS 756.040 and applicable U. S. Supreme Court precedent. I expect other representative samples of electric utilities would have similar averages of authorized and realized ROEs. DCF estimates for utilities in other industries are also useful and provide valuable perspective. I also recommend the Commission consider at least three types of models in addition to the DCF model.

Q. What is the first type of model you recommend be considered?

A. The first type of model is the risk premium model that PGE calls the risk positioning model. In PGE's analysis, they show authorized ROEs vary directly (and thus risk premiums vary indirectly) with both corporate bonds and Treasury security rates. The California PUC found that when it considered DCF models, RP models, the capital asset pricing model and other information presented by numerous parties in its determinations of authorized ROEs for energy utilities, costs of equity increase (decrease) by one-half to two-thirds as much as increases (decreases) in benchmark equity cost estimates (California PUC Decision 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). PGE's risk positioning analyses found the same relationship. Mathematically, if risk premiums vary inversely with interest rates but the absolute value of the expected change in the risk premium is less than the change in interest rates, it also means equity costs move in the same direction as interest rates but by less.

I conducted similar analyses for natural gas distribution utilities and water utilities and also found costs of equity increase by one-half to two-thirds as much as the increases in interest rates. The analyses presented by PGE are consistent with analyses I have done in the past and changes in interest rates and ROEs the California PUC observed occur during its annual updates of authorized ROEs for energy utilities. It is my understanding that PGE is responding to Staff comments about their risk positioning analyses and thus I do not.

Q. What is the second model you believe the Commission should consider?

A. The second model is a risk premium model that adopts actual earned ROEs for utilities in Mr. Morgan's sample as proxies for the costs of equity. In conducting this risk premium analysis, I assume regulators attempt to provide utilities reasonable opportunities to earn their costs of equity. If rates and rate adjustment mechanisms authorized by regulators give utilities a reasonable opportunity to earn their costs of equity, the average of such earned ROEs should provide an indication of the cost of equity. In some years an individual utility will make less and in other years earn more than its cost of equity. Also, in any given year, some utilities will make more and others will make less than their costs of equity. As a result, a risk premium analysis based on averages of realized ROEs for Mr. Morgan's sample should provide useful information for the Commission about the cost of equity for a typical utility in his sample.

My analysis is reported in PGE Exhibit 2109. The Department of Ratepayer Advocates of the California PUC ("DRA") routinely uses this method to determine forward-looking equity costs. See for example, Division of Ratepayer Advocates, *Report of the Cost of Capital for San Jose Water,* June 2006, Application 06-02-014, Table 2-7. In that analysis, DRA adopted annual averages of actual realized ROEs for its sample of utilities as proxies for the costs of equity for the period 1996-2005, subtracted contemporaneous Treasury rates from those equity cost proxies to determine annual average risk premiums, then added the 5-year and the 10-year averages of those risk premiums to forecasts of the respective Treasury rates to determine an equity cost range. PGE Exhibit 2109 is the DRA analysis but with data for Mr. Morgan's sample companies substituted for the sample data used by DRA.

Q. What are the results of your analysis?

A. The risk premium analysis in PGE Exhibit 2109 indicates the average cost of equity for Mr. Morgan's sample is expected to be 11.0% in 2007. Because PGE is more risky than Mr. Morgan's sample, the analysis indicates PGE has an equity cost in excess of 11.0%.

Q. At Staff Exhibit 1000, page 23, Mr. Morgan objects to PGE's risk positioning model because authorized ROEs are only one component involved in setting revenue requirements. How does the model you present in PGE Exhibit 2109 differ?

A. It differs in that the realized ROEs result from "all of the components" involved in setting the overall revenue requirement. While I strongly disagree with the suggestion that relying upon authorized ROEs produces a flawed analysis, the analysis in PGE Exhibit 2109 is different than such an approach in that it considers the bottom line resulting from all of the components the various commissions considered when setting rates and rate adjustment mechanisms for those utilities.

Q. What is the third risk premium model you believe the Commission should consider?

A. There are various methods that can be used to determine the risk premium used in a risk premium analysis. At Staff Exhibit 1003, page 48, Mr. Morgan points out that

$$K = [(P_1 - P_0) + D_1] / P_0,$$

where K is the holding period return for a year in which the initial price was P_0, P_1 is the price at the end of the year and D_1 is the dividend paid during the year. I derived a third risk premium method with such annual market holding period returns, contemporaneous interest rates and the assumption that investors expect the future risk premium to be similar to the average risk premium in the past. With this risk premium approach, the expected risk premium E(RP) is found as an average of realized annual risk premiums (K_i) over a relatively long period of time (n years).

$$E(RP) = \sum(K_i)/n + \sum (D_i)/n$$

In making this risk premium estimate, it is assumed that the average of differences between expected and realized return premiums, $\sum(D_i)/n$, will approach zero if the time period is long enough. The analysis also assumes the average risk premium in the past is the same as the risk premium expected in the future. But, since "Baa" rates of 7.2% expected in 2007 are lower than the average of "Baa" rates of 8.0% during 1950 to 2004, the average future risk premium is expected to be higher today than in the simple average based on past data. Thus, this method provides a conservative indication of the cost of equity.

PGE Exhibit 2110 shows application of this method to data for Moody's Electric Utility Common Stocks over the period 1950 to 2005. When Mergent purchased Moody's, it stopped updating this index. Data for the period 2001 to 2005 are derived by constructing an index of electric utility returns from data for six utilities in Mr. Morgan's sample and the original Moody's sample. Over this period, the average premium of returns for the Moody's electric utilities was 3.55% higher than rates for "Baa" bonds. With an expected "Baa" rate of 7.2% in 2007, the indicated benchmark cost of equity is 10.75%.

Q. Does this complete your prefiled rebuttal testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2101	Comparison of Risk Factors for PGE, NW Natural, and Staff's Sample
2102	Change in 7-Year Treasuries since UG 152
2103	Earned and Authorized ROEs of Staff's Sample
2104	DCF Estimates for Water Utilities Sample
2105	Restated Staff 40-Year DCF Model: include "sv" growth
2106	Restated Staff 40-Year DCF Model: First Stage ending in 2010
2107	Examination of Bias in Value Line forecasts
2108	Analysis of Equity Costs and Risk Premiums of Value Line Industrial Composite
2109	California DRA Risk Premium Model with Staff's Data
2110	Risk Premium Model based on Moody's Electric Utilities Sample

Comparison of Risk Factors for PGE, NW Natural and Mr. Morgan's Electric Utilities Sample

	S&P Business Profile[a/]	Value Line Beta[b/]	Value Line Safety Rank[b/]	S&P Bond Rating[c/]	Percentage of Purchased Power[b/]
Mr. Morgan's Electric Utilty Sample					
1 Alliant Energy	5	0.90	3	A-	33%
2 AEP	2	1.25	3	BBB	na
3 Consol Edison	2	0.70	1	A	100%
4 Empire District	6	0.80	3	BBB+	30%
5 Energy East Corp.	3	0.90	2	BBB+	100%
6 IDACORP, Inc.	5	1.00	3	A-	22%
7 MGE Energy Inc.	4	0.70	1	AA-	37%
8 NSTAR	1	0.80	1	A+	na
9 OGE Energy	4	0.75	2	BBB+	12%
10 Progress Energy	5	0.85	2	BBB	0%
11 Southern Co.	4	0.65	1	A	5%
12 Wisconsin Energy	5	0.80	2	A-	18%
13 WPS Resources	4	0.80	2	A+	36%
14 Xcel Energy	5	0.90	2	A-	30%
Average	3.9	0.84	2.0	A-	35%
PGE	5	na	na	BBB+	49%
NW Natural	1	0.75	1	AA-	--

Sources and Notes:

a/ From Staff/1003 Morgan/119 to 124. A business profile of 1 is the least risky.

b/ From Staff/ 1003 Morgan/56 to112.

d/ AUS Utilty Reports, August 2006, except PGE. PGE as reported in Staff/1003 Morgan/124..

09/02/06

Implied Cost of Equity Range for PGE Based on
NW Natural's Last Order and Changes in 7-Year Treasury Rates

	Highest Rate		Lowest Rate
7-Year Treasury Rates at the time of UG152 for the period July 2003 to November 2003	3.96%		3.45%
Current 7-Year Treasury Rate (August 29, 2006)		4.77%	
Increase in 7-year Treasury Rates	0.81%		1.32%
Apply results of the PGE RP Model to Estimate the indicated increase in Required ROE	0.46%		0.75%
Indicated Conservative ROE Range for PGE	10.66%	to	10.95%

09/02/2006

Earned and Authorized ROEs for Utilities in
Mr. Morgan's Sample of Electric Utilities

		Earned ROE	Authorized ROE		
1	Alliant Energy	10.80%	11.09%	_a/	VL
2	AEP	11.70%	11.09%	_b/	VL-AUS
3	Consol Edison	10.00%	11.08%	_b/	VL-AUS
4	Empire District	6.00%	11.00%	_a/	VL
5	Energy East Corp.	9.30%	10.77%	_b/	VL-AUS
6	IDACORP, Inc.	9.30%	10.25%	_a/	VL
7	MGE Energy Inc.	10.30%	11.00%	_c/	AUS
8	NSTAR	13.20%	10.50%	_a/	VL
9	OGE Energy	12.60%	10.75%	_a/	VL
10	Progress Energy	9.30%	12.42%	_b/	VL-AUS
11	Southern Co.	14.40%	12.20%	_c/	AUS
12	Wisconsin Energy	11.60%	11.20%	_a/	VL
13	WPS Resources	13.10%	11.00%	_a/	VL
14	Xcel Energy	9.40%	11.12%	_b/	VL-AUS
	Average	10.8%	11.1%		

Notes and Sources

a/ Data reported by Value Line. Lower than data reported by AUS Utility Reports.

b/ The lesser of ROEs reported by Value Line and AUS Utility Reports, August 2006.

c/ Data from AUS Utility Reports, August 2006. Lower than data reported by Value Line.

09/02/2006

DCF Estimate for Water Utilties Sample

		Current Yield[a/]	Expected Growth[b/]	DCF Yield[c/]	Equity Cost Estimate[d/]
1	American States	2.50%	6.00%	2.66%	8.66%
2	Aqua America	2.12%	9.77%	2.32%	12.09%
3	Artesian Resources	3.18%	10.83%	3.52%	14.35%
4	California Water Service	3.20%	8.33%	3.46%	11.80%
5	Middlesex Water	3.72%	3.75%	3.86%	7.61%
6	York Water	2.62%	7.60%	2.82%	10.42%
7	Average	2.89%	7.71%	3.11%	10.82%

Notes and Sources:

a/ Average of dividend yields during June, July and August 2006.
b/ Average of growth rates reported by Zacks, First Call and S&P Earnings Guide reported on the Internet August 18, 2006.
c/ Current yield times (1 + growth rate).
d/ DCF yield plus growth.

09/02/06

Restate Staff 40-Year DCF Analysis with Three Changes: Adopt Value Line Forecast of Future Earned ROEs, Include VS Growth and Assume Investors Expect Future Pattern of EPS Growth to Match Past EPS Growth During First Stage

	Year	[1] Year-end Book Value	[2] Retention Ratio	[3] DPS growth	[4] EPS growth	[5a] Retained Earnings per Share	[5b] Gain from Sales of Stock Above Book Value	[6] Total Increment to Book Value	[7] Market Price	[8] M/B	[9] ROE	[10] Cash Flow From Stock Transfer	[11] Cash Flow from Dividends	[12] Total Cash Flow
	2005 [a/]	$20.13							$33.79	1.73		-$33.79		-$33.79
	2006 [a/]	$20.98	0.343	$1.47	$2.24				$36.30	1.73	10.88%		$1.47	$1.47
	2007	$21.78	0.317	$1.51	$2.22	$0.70	$0.10	$0.80	$37.68	1.73	10.41%		$1.51	$1.51
	2008	$22.91	0.397	$1.56	$2.59	$1.03	$0.10	$1.13	$39.63	1.73	11.63%		$1.56	$1.56
First	2009	$24.17	0.419	$1.61	$2.76	$1.16	$0.11	$1.27	$41.82	1.73	11.80%		$1.61	$1.61
Stage	2010	$25.43	0.408	$1.65	$2.80	$1.14	$0.11	$1.25	$43.99	1.73	11.32%		$1.65	$1.65
	2011	$27.21	0.494	$1.70	$3.36	$1.66	$0.12	$1.78	$47.07	1.73	12.84%		$1.70	$1.70
	2012	$28.82	0.459	$1.75	$3.24	$1.49	$0.13	$1.61	$49.86	1.73	11.62%		$1.75	$1.75
	2013	$30.82	0.508	$1.81	$3.67	$1.86	$0.13	$2.00	$53.32	1.73	12.37%		$1.81	$1.81
	2014	$33.08	0.532	$1.86	$3.98	$2.12	$0.14	$2.26	$57.23	1.73	12.50%		$1.86	$1.86
	2015	$35.53	0.545	$1.92	$4.21	$2.30	$0.15	$2.45	$61.47	1.73	12.34%		$1.92	$1.92
	2016	$38.19	0.545	$2.02	$4.44	$2.50	$0.17	$2.67	$66.08	1.73	12.50%		$2.02	$2.02
	2017	$41.06	0.545	$2.17	$4.77	$2.69	$0.18	$2.87	$71.03	1.73	12.50%		$2.17	$2.17
	2018	$44.14	0.545	$2.34	$5.13	$2.89	$0.19	$3.08	$76.36	1.73	12.50%		$2.34	$2.34
	2019	$47.45	0.545	$2.51	$5.52	$3.11	$0.21	$3.31	$82.09	1.73	12.50%		$2.51	$2.51
	2020	$51.01	0.545	$2.70	$5.93	$3.34	$0.22	$3.56	$88.25	1.73	12.50%		$2.70	$2.70
	2021	$54.84	0.545	$2.90	$6.38	$3.59	$0.24	$3.83	$94.87	1.73	12.50%		$2.90	$2.90
	2022	$58.95	0.545	$3.12	$6.85	$3.86	$0.26	$4.11	$101.98	1.73	12.50%		$3.12	$3.12
	2023	$63.37	0.545	$3.35	$7.37	$4.15	$0.27	$4.42	$109.63	1.73	12.50%		$3.35	$3.35
Second	2024	$68.13	0.545	$3.60	$7.92	$4.46	$0.29	$4.75	$117.86	1.73	12.50%		$3.60	$3.60
Stage	2025	$73.24	0.545	$3.87	$8.52	$4.79	$0.32	$5.11	$126.70	1.73	12.50%		$3.87	$3.87
	2026	$78.73	0.545	$4.17	$9.15	$5.15	$0.34	$5.49	$136.20	1.73	12.50%		$4.17	$4.17
	2027	$84.64	0.545	$4.48	$9.84	$5.54	$0.37	$5.91	$146.42	1.73	12.50%		$4.48	$4.48
	2028	$90.99	0.545	$4.81	$10.58	$5.96	$0.39	$6.35	$157.41	1.73	12.50%		$4.81	$4.81
	2029	$97.81	0.545	$5.18	$11.37	$6.40	$0.42	$6.83	$169.21	1.73	12.50%		$5.18	$5.18
	2030	$105.15	0.545	$5.56	$12.23	$6.88	$0.45	$7.34	$181.91	1.73	12.50%		$5.56	$5.56
	2031	$113.04	0.545	$5.98	$13.14	$7.40	$0.49	$7.89	$195.55	1.73	12.50%		$5.98	$5.98
	2032	$121.52	0.545	$6.43	$14.13	$7.95	$0.53	$8.48	$210.22	1.73	12.50%		$6.43	$6.43
	2033	$130.63	0.545	$6.91	$15.19	$8.55	$0.57	$9.12	$225.99	1.73	12.50%		$6.91	$6.91
	2034	$140.43	0.545	$7.43	$16.33	$9.19	$0.61	$9.80	$242.95	1.73	12.50%		$7.43	$7.43
	2035	$150.97	0.545	$7.99	$17.55	$9.88	$0.65	$10.53	$261.17	1.73	12.50%		$7.99	$7.99
	2036	$162.29	0.545	$8.59	$18.87	$10.62	$0.70	$11.32	$280.76	1.73	12.50%		$8.59	$8.59
	2037	$174.46	0.545	$9.23	$20.29	$11.42	$0.75	$12.17	$301.82	1.73	12.50%		$9.23	$9.23
	2038	$187.55	0.545	$9.92	$21.81	$12.28	$0.81	$13.09	$324.46	1.73	12.50%		$9.92	$9.92
	2039	$201.62	0.545	$10.67	$23.44	$13.20	$0.87	$14.07	$348.80	1.73	12.50%		$10.67	$10.67
	2040	$216.75	0.545	$11.47	$25.20	$14.19	$0.94	$15.12	$374.97	1.73	12.50%		$11.47	$11.47
	2041	$233.00	0.545	$12.33	$27.09	$15.25	$1.01	$16.26	$403.10	1.73	12.50%		$12.33	$12.33
	2042	$250.48	0.545	$13.25	$29.13	$16.40	$1.08	$17.48	$433.34	1.73	12.50%		$13.25	$13.25
	2043	$269.27	0.545	$14.25	$31.31	$17.63	$1.16	$18.79	$465.84	1.73	12.50%		$14.25	$14.25
	2044	$289.47	0.545	$15.32	$33.66	$18.95	$1.25	$20.20	$500.79	1.73	12.50%		$15.32	$15.32
3rd Stage	2045	$311.19	0.545	$16.46	$36.18	$20.37	$1.35	$21.72	$538.36	1.73	12.50%	$538.36	$16.46	$554.82

Internal Rate of Return	10.50%

Notes and Sources for Each Column

a/ Initial values for 2005 and 2006 in all columns are from Staff/1002 Morgan/6.
[1] Book Value from prior year plus increment in colum [6].
[2] First stage values derived from estimated EPS and DPS. Second stage assumes value from 2015 continues.
[3] First stage growth of 3% from Staff/1002 Morgan/6. Values in Stage 2 are derived from EPS and Retention ratio.
[4] First stage assumes investors expect the same pattern of EPS growth in 2006-2015 as the average of changes in EPS realized by utilities in Mr. Morgan's sample during 1996-2005. Second stage EPS growth is computed by multiplying values in column [1] by column [9].
[5a] BR growth computed by subtracting DPS from EPS. Adjusted in Second Stage for 12.5% ROE being return on year-end equity.
[5b] SV growth is determined by multiplying estimated sv growth by beginning book value to be conservative.
[6] The sum of columns [5a] and [5b].
[7] Col [1] times col. [10].
[8] From Staff 1002 Morgan/6
[9] First stage ROE is derived. Second stage ROE is the ROE forecasted by Value Line for the East (Staff/1003 Morgan/97), the Central (Staff 1003 Morgan/98) and the West (Staff/1003 Morgan/96).
[10] Inputs are negative when stock is purchased and positive when it is sold.
[11] Column [3]
[12] Sum of columns 10 and 11.

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Mr. Morgan's DCF Analysis as Modififed with Assumptions for Rebuttal Table 9 but with First Stage Ending in 2010

	Year	[1] Year-end Book Value	[2] Retention Ratio	[3] DPS growth	[4] EPS growth	[5a] Retained Earnings per Share	[5b] Gain from Sales of Stock Above Book Value	[6] Total Increment to Book Value	[7] Market Price	[8] M/B	[9] ROE	[10] Cash Flow From Stock Transfer	[11] Cash Flow from Dividends	[12] Total Cash Flow
	2005[a/]	$20.13							$33.79	1.73		-$33.79		-$33.79
	2006[a/]	$20.98	0.343	$1.47	$2.24				$36.30	1.73	10.88%		$1.47	$1.47
First	2007	$22.00	0.378	$1.51	$2.43	$0.92	$0.10	$1.02	$38.06	1.73	11.38%		$1.51	$1.51
Stage	2008	$23.19	0.412	$1.56	$2.65	$1.09	$0.10	$1.19	$40.12	1.73	11.78%		$1.56	$1.56
	2009	$24.58	0.443	$1.61	$2.88	$1.28	$0.11	$1.39	$42.52	1.73	12.13%		$1.61	$1.61
	2010	$26.17	0.473	$1.65	$3.14	$1.48	$0.11	$1.60	$45.28	1.73	12.42%		$1.65	$1.65
	2011	$27.89	0.473	$1.72	$3.27	$1.59	$0.12	$1.71	$48.25	1.73	12.50%		$1.72	$1.72
6.55%	2012	$29.71	0.473	$1.84	$3.49	$1.70	$0.13	$1.83	$51.41	1.73	12.50%		$1.84	$1.84
	2013	$31.66	0.473	$1.96	$3.71	$1.81	$0.14	$1.95	$54.77	1.73	12.50%		$1.96	$1.96
	2014	$33.73	0.473	$2.09	$3.96	$1.93	$0.15	$2.07	$58.36	1.73	12.50%		$2.09	$2.09
	2015	$35.94	0.473	$2.22	$4.22	$2.05	$0.16	$2.21	$62.18	1.73	12.50%		$2.22	$2.22
6.55%	2016	$38.29	0.473	$2.37	$4.49	$2.19	$0.17	$2.35	$66.25	1.73	12.50%		$2.37	$2.37
	2017	$40.80	0.473	$2.52	$4.79	$2.33	$0.18	$2.51	$70.59	1.73	12.50%		$2.52	$2.52
	2018	$43.47	0.473	$2.69	$5.10	$2.48	$0.19	$2.67	$75.21	1.73	12.50%		$2.69	$2.69
	2019	$46.32	0.473	$2.86	$5.43	$2.64	$0.20	$2.85	$80.13	1.73	12.50%		$2.86	$2.86
	2020	$49.35	0.473	$3.05	$5.79	$2.82	$0.22	$3.03	$85.38	1.73	12.50%		$3.05	$3.05
	2021	$52.59	0.473	$3.25	$6.17	$3.00	$0.23	$3.23	$90.97	1.73	12.50%		$3.25	$3.25
	2022	$56.03	0.473	$3.46	$6.57	$3.20	$0.24	$3.44	$96.93	1.73	12.50%		$3.46	$3.46
	2023	$59.70	0.473	$3.69	$7.00	$3.41	$0.26	$3.67	$103.28	1.73	12.50%		$3.69	$3.69
Second	2024	$63.61	0.473	$3.93	$7.46	$3.63	$0.28	$3.91	$110.04	1.73	12.50%		$3.93	$3.93
Stage	2025	$67.77	0.473	$4.19	$7.95	$3.87	$0.30	$4.16	$117.24	1.73	12.50%		$4.19	$4.19
	2026	$72.21	0.473	$4.46	$8.47	$4.12	$0.32	$4.44	$124.92	1.73	12.50%		$4.46	$4.46
	2027	$76.94	0.473	$4.76	$9.03	$4.39	$0.34	$4.73	$133.10	1.73	12.50%		$4.76	$4.76
	2028	$81.97	0.473	$5.07	$9.62	$4.68	$0.36	$5.04	$141.81	1.73	12.50%		$5.07	$5.07
	2029	$87.34	0.473	$5.40	$10.25	$4.99	$0.38	$5.37	$151.10	1.73	12.50%		$5.40	$5.40
	2030	$93.06	0.473	$5.75	$10.92	$5.31	$0.41	$5.72	$160.99	1.73	12.50%		$5.75	$5.75
	2031	$99.15	0.473	$6.13	$11.63	$5.66	$0.43	$6.09	$171.53	1.73	12.50%		$6.13	$6.13
	2032	$105.65	0.473	$6.53	$12.39	$6.03	$0.46	$6.49	$182.77	1.73	12.50%		$6.53	$6.53
	2033	$112.56	0.473	$6.96	$13.21	$6.43	$0.49	$6.92	$194.73	1.73	12.50%		$6.96	$6.96
	2034	$119.93	0.473	$7.41	$14.07	$6.85	$0.52	$7.37	$207.48	1.73	12.50%		$7.41	$7.41
	2035	$127.79	0.473	$7.90	$14.99	$7.30	$0.56	$7.85	$221.07	1.73	12.50%		$7.90	$7.90
	2036	$136.15	0.473	$8.42	$15.97	$7.77	$0.59	$8.37	$235.55	1.73	12.50%		$8.42	$8.42
	2037	$145.07	0.473	$8.97	$17.02	$8.28	$0.63	$8.92	$250.97	1.73	12.50%		$8.97	$8.97
	2038	$154.57	0.473	$9.56	$18.13	$8.82	$0.67	$9.50	$267.40	1.73	12.50%		$9.56	$9.56
	2039	$164.69	0.473	$10.18	$19.32	$9.40	$0.72	$10.12	$284.91	1.73	12.50%		$10.18	$10.18
	2040	$175.47	0.473	$10.85	$20.59	$10.02	$0.77	$10.78	$303.57	1.73	12.50%		$10.85	$10.85
	2041	$186.96	0.473	$11.56	$21.93	$10.67	$0.82	$11.49	$323.44	1.73	12.50%		$11.56	$11.56
	2042	$199.20	0.473	$12.32	$23.37	$11.37	$0.87	$12.24	$344.62	1.73	12.50%		$12.32	$12.32
	2043	$212.25	0.473	$13.12	$24.90	$12.12	$0.93	$13.04	$367.19	1.73	12.50%		$13.12	$13.12
	2044	$226.14	0.473	$13.98	$26.53	$12.91	$0.99	$13.90	$391.23	1.73	12.50%		$13.98	$13.98
3rd Stage	2045	$240.95	0.473	$14.90	$28.27	$13.76	$1.05	$14.81	$416.85	1.73	12.50%	$416.85	$14.90	$431.74

Internal Rate of Return	10.31%

Notes and Sources for Each Column

a/	Initial values for 2005 and 2006 in all columns are from Staff/1002 Morgan/6.
[1]	Book Value from prior year plus increment in colum [6].
[2]	First stage values derived from estimated EPS and DPS. Second stage assumes value from 2010 continues.
[3]	First stage growth of 3% from Staff/1002 Morgan/6. Values in stage 2 are derived from EPS and Retention ratio.
[4]	First stage assumes investors expect the same pattern of EPS growth in 2006-2010 as the average of changes in EPS realized by utilities in Mr. Morgan's sample during 2001-2005. Second stage EPS growth is computed by multiplying values in column [1] by column [9].
[5a]	BR growth computed by subtracting DPS from EPS. Adjusted in Second Stage for 12.5% ROE being return on year-end equity.
[5b]	SV growth is determined by multiplying estimated sv growth by beginning book value to be conservative.
[6]	The sum of columns [5a] and [5b].
[7]	Col [1] times col. [10].
[8]	From Staff 1002 Morgan/6
[9]	First stage ROE is derived. Second stage ROE is the ROE forecasted by Value Line for the East (Staff/1003 Morgan/97), the Central (Staff 1003 Morgan/98) and the West (Staff/1003 Morgan/96).
[10]	Inputs are negative when stock is purchased and positive when it is sold.
[11]	Column [3]
[12]	Sum of columns 10 and 11.

09/02/06

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	Actual 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.

09/02/2006

Analysis of Equity Costs and Risk Premiums Based on DCF Analyses of the Value Line Industrial Composite: 1986 to 2006

	Study Date	Dividend Yield	Expected Growth[b/]	DCF Equity Cost	Long-term Treasury Lag 1 Mnth	Risk Premium	Line BR (Published)	to FERC br
1	1/86	3.80%	8.85%	12.65%	9.54%	3.11%	8.50%	8.8%
2	2/87	3.00%	9.39%	12.39%	7.39%	5.00%	9.00%	9.39%
3	2/88	3.10%	9.93%	13.03%	8.83%	4.20%	9.50%	9.93%
4	7/88	3.50%	7.77%	11.27%	9.00%	2.27%	7.50%	7.77%
5	2/89	3.50%	7.77%	11.27%	8.93%	2.34%	7.50%	7.77%
6	2/90	3.20%	7.77%	10.97%	8.26%	2.71%	7.50%	7.77%
7	1/91	3.70%	9.93%	13.63%	8.24%	5.39%	9.50%	9.93%
8	2/92	2.80%	9.39%	12.19%	7.58%	4.61%	9.00%	9.39%
9	2/93	2.90%	8.31%	11.21%	7.34%	3.87%	8.00%	8.31%
10	2/94	3.00%	8.31%	11.31%	6.39%	4.92%	8.00%	8.31%
11	2/95	2.70%	9.93%	12.63%	7.97%	4.66%	9.50%	9.93%
12	3/96	2.70%	10.48%	13.18%	6.03%	7.15%	10.00%	10.48%
13	2/97	2.40%	12.13%	14.53%	6.91%	7.62%	11.50%	12.13%
14	1/98	1.50%	14.92%	16.42%	6.07%	10.35%	14.00%	14.92%
15	1/99	1.30%	16.05%	17.35%	5.36%	11.99%	15.00%	16.05%
16	2/00	0.80%	16.05%	16.85%	6.86%	9.99%	15.00%	16.05%
17	7/00	1.00%	14.92%	15.92%	6.28%	9.64%	14.00%	14.92%
18	2/01	1.20%	13.79%	14.99%	5.65%	9.34%	13.00%	13.79%
19	7/01	1.20%	12.13%	13.33%	5.82%	7.51%	11.50%	12.13%
20	1/02	1.20%	12.13%	13.33%	5.76%	7.57%	11.50%	12.13%
21	8/02	1.60%	12.68%	14.28%	5.51%	8.77%	12.00%	12.68%
22	1/03	1.60%	12.13%	13.73%	5.01%	8.72%	11.50%	12.13%
23	7/03	1.50%	11.57%	13.07%	4.34%	8.73%	11.00%	11.57%
24	3/04	1.60%	12.13%	13.73%	4.94%	8.79%	11.50%	12.13%
25	10/04	1.80%	11.57%	13.37%	4.89%	8.48%	11.00%	11.57%
26	4/05	1.90%	11.57%	13.47%	4.89%	8.58%	11.00%	11.57%
27	11/05	2.10%	12.68%	14.78%	4.74%	10.04%	12.00%	12.68%
28	5/06	2.10%	12.68%	14.78%	5.22%	9.56%	12.00%	12.7%

Averages for:	
All years (1986-2006)	7.0%
Last 15 years (1992-2006)	8.1%
Last 10 years (1997-2006)	9.1%

Notes and Sources:
a/ Data obtained from *Value Line's* studies of the Industrial Composite.
b/ Projected growth from retained earnings restated with FERC formula.

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Risk Premium Analysis Method Used by Department of Ratepayer Advocates of the California PUC[a/] but with Data for Mr. Morgan's Sample

	Return on Equity[b/]	Annual Averages: Long-term Treasury[c/]	Annual Averages: 10-Year Treasury[c/]	Risk Premiums: Long-term Treasury	Risk Premiums: 10-Year Treasury
1996	12.54%	6.70%	6.44%	5.84%	6.10%
1997	10.49%	6.61%	6.35%	3.88%	4.14%
1998	11.11%	5.58%	5.26%	5.53%	5.85%
1999	11.58%	5.87%	5.64%	5.71%	5.94%
2000	12.14%	5.94%	6.03%	6.20%	6.11%
2001	11.69%	5.49%	5.02%	6.20%	6.67%
2002	10.06%	5.42%	4.61%	4.64%	5.45%
2003	10.50%	5.05%	4.02%	5.45%	6.48%
2004	9.87%	5.12%	4.27%	4.75%	5.60%
2005	10.59%	4.56%	4.29%	6.03%	6.30%
	10-Year Average Premium			5.42%	5.86%
	5-year Average Premium			5.41%	6.10%
	Expected Treasury Rates for 2007[d/]			5.35%	5.20%
	Projected Returns on Equity				
	10-Year Average			10.8%	11.1%
	5-Year Average			10.8%	11.3%
	Overall Average			11.0%	

Notes and Sources:

a/ See for example, Division of Ratepayer Advocates, CPUC, *Report on the Cost of Capital for San Jose Water,* June 2006, A.06-02-014, Table 2-7.

b/ Average of Earned ROEs for the 14 Utilities and their predecessors in Mr. Morgan's Sample. Data obtained from various editions of C.A. Turner (AUS) Utilities Reports, 1996-2005.

c/ Source: Table 2-7 in California DRA Cost of Capital Report in A.06-02-014.

d/ Average of Value Line's forecast, dated August 25, 2006 and the Blue Chip concenus forecast for Mid-2007 reported by Blue Chip in August 2006.

09/02/2006

Risk Premium Analysis Based on Holding Period Returns for Moody's Electric Utilities Sample as Updated, 1950 to 2005

	Baa Corporate Bond Rate[a]	Year-end Price Index[b]	Annual Average Dividend[b]	Index Gain/Loss	Dividend Yield	Total Return	Risk Premium
1950	3.20%	$30.81					
1951	3.61%	$33.85	$1.88	9.87%	6.10%	15.97%	12.77%
1952	3.51%	$37.85	$1.91	11.82%	5.64%	17.46%	13.85%
1953	3.74%	$39.61	$2.01	4.65%	5.31%	9.96%	6.45%
1954	3.45%	$47.56	$2.13	20.07%	5.38%	25.45%	21.71%
1955	3.62%	$49.35	$2.21	3.76%	4.65%	8.41%	4.96%
1956	4.37%	$48.96	$2.32	-0.79%	4.70%	3.91%	0.29%
1957	5.03%	$50.30	$2.43	2.74%	4.96%	7.70%	3.33%
1958	4.85%	$66.37	$2.50	31.95%	4.97%	36.92%	31.89%
1959	5.28%	$65.77	$2.61	-0.90%	3.93%	3.03%	-1.82%
1960	5.10%	$76.82	$2.68	16.80%	4.07%	20.88%	15.60%
1961	5.10%	$99.32	$2.81	29.29%	3.66%	32.95%	27.85%
1962	4.92%	$96.49	$2.97	-2.85%	2.99%	0.14%	-4.96%
1963	4.85%	$102.31	$3.21	6.03%	3.33%	9.36%	4.44%
1964	4.81%	$115.54	$3.43	12.93%	3.35%	16.28%	11.43%
1965	5.02%	$114.86	$3.86	-0.59%	3.34%	2.75%	-2.06%
1966	6.18%	$105.99	$4.11	-7.72%	3.58%	-4.14%	-9.16%
1967	6.93%	$98.19	$4.34	-7.36%	4.09%	-3.26%	-9.44%
1968	7.23%	$104.04	$4.50	5.96%	4.58%	10.54%	3.61%
1969	8.65%	$84.62	$4.61	-18.67%	4.43%	-14.23%	-21.46%
1970	9.12%	$88.59	$4.70	4.69%	5.55%	10.25%	1.60%
1971	8.38%	$85.56	$4.77	-3.42%	5.38%	1.96%	-7.16%
1972	7.93%	$83.61	$4.87	-2.28%	5.69%	3.41%	-4.97%
1973	8.48%	$60.87	$5.01	-27.20%	5.99%	-21.21%	-29.14%
1974	10.63%	$41.17	$4.83	-32.36%	7.93%	-24.43%	-32.91%
1975	10.56%	$55.66	$4.97	35.20%	12.07%	47.27%	36.64%
1976	9.12%	$66.29	$5.18	19.10%	9.31%	28.40%	17.84%
1977	8.99%	$68.19	$5.54	2.87%	8.36%	11.22%	2.10%
1978	9.94%	$59.75	$5.81	-12.38%	8.52%	-3.86%	-12.85%
1979	12.06%	$56.41	$6.22	-5.59%	10.41%	4.82%	-5.12%
1980	14.64%	$54.42	$6.58	-3.53%	11.66%	8.14%	-3.92%
1981	16.55%	$57.20	$6.99	5.11%	12.84%	17.95%	3.31%
1982	14.14%	$70.26	$7.43	22.83%	12.99%	35.82%	19.27%
1983	13.75%	$72.03	$7.87	2.52%	11.20%	13.72%	-0.42%
1984	13.40%	$80.16	$8.26	11.29%	11.47%	22.75%	9.00%
1985	11.58%	$94.98	$8.61	18.49%	10.74%	29.23%	15.83%
1986	9.97%	$113.66	$8.89	19.67%	9.36%	29.03%	17.45%
1987	11.29%	$94.24	$9.12	-17.09%	8.02%	-9.06%	-19.03%
1988	10.65%	$100.94	$8.87	7.11%	9.41%	16.52%	5.23%
1989	9.82%	$122.52	$8.82	21.38%	8.74%	30.12%	19.47%
1990	10.43%	$117.77	$8.79	-3.88%	7.17%	3.30%	-6.52%
1991	9.26%	$144.02	$8.95	22.29%	7.60%	29.89%	19.46%
1992	8.81%	$141.06	$9.05	-2.06%	6.28%	4.23%	-5.03%
1993	7.69%	$146.70	$8.99	4.00%	6.37%	10.37%	1.56%
1994	9.10%	$115.50	$8.96	-21.27%	6.11%	-15.16%	-22.85%
1995	7.49%	$142.90	$9.02	23.72%	7.81%	31.53%	22.43%
1996	7.89%	$136.00	$9.06	-4.83%	6.34%	1.51%	-5.98%
1997	7.32%	$155.73	$9.06	14.51%	6.66%	21.17%	13.28%
1998	7.23%	$181.84	$7.83	16.77%	5.03%	21.79%	14.47%
1999	8.19%	$137.30	$8.10	-24.49%	4.45%	-20.04%	-27.27%
2000	8.02%	$227.09	$8.27	65.40%	6.02%	71.42%	63.23%
2001	8.05%	$207.15	$8.37	-8.78%	3.68%	-5.10%	-13.12%
2002	7.45%	$210.86	$8.46	1.79%	4.09%	5.88%	-2.17%
2003	6.60%	$201.14	$7.99	-4.61%	3.79%	-0.82%	-8.27%
2004	6.15%	$231.21	$7.93	14.95%	3.94%	18.89%	12.29%
2005	6.32%	$233.46	$8.11	0.98%	3.51%	4.48%	-1.67%
Average	8.00%			Average risk premium			3.55%
				Expected Baa rate in 2007			7.20%
				Indicated Cost of Equity			10.75%

Notes and Sources:

a/ Federal Reserve data. Monthly rates for December of the indicated year.

b/ Mergent, Moody's 2001 Public Utility Manual with updates for 2001-2005.

09/02/2006

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 rebuttal testimony?

A. The purpose of this rebuttal 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 regarding Schedule 76R, Economic Replacement Power. We do not discuss the various marginal cost, ratespread, rate design, and other partial requirements issues raised by Staff, ICNU, CUB, and Fred Meyer because we believe that a settlement has been reached between PGE and these parties. We also believe that the settlement is satisfactory to the City of Portland regarding their concerns about Schedule 75, Partial Requirements Service. Should this settlement for any reason not be finalized, PGE will have to file supplemental testimony on the issues identified by parties in their Opening Testimony.

II. Non-streetlighting Issues

Q. Please summarize the non-streetlighting related modifications proposed by the Cities.

A. The City of Portland in Exhibit COP/300 proposes that PGE revise Schedule 38 (a previously closed schedule) to be applicable to all customers whose demand is less than 1,000 kW in order that they may experience on- and off-peak differentiated energy charges. Other non-streetlighting issues raised include service restoration priorities (by the Cities), and modifications to the Customer Impact Offset (CIO) proposed by COP and COG.

Q. Please review PGE's proposal regarding Schedule 38.

A. Schedule 38 is an optional Large Non-residential Schedule that has been closed to new service since October 2001. The Energy Charge is on- and off-peak differentiated, however these on- and off-peak hours do not conform to the standard of six days by sixteen hours on-peak. Instead, the on-peak hours are limited to thirteen hours per day Monday-Friday. In this proceeding we proposed reopening this schedule to current Schedule 83 customers whose demand does not exceed 200 kW in order to mitigate the bill impacts of mid-size seasonal customers. Specifically, we proposed reopening this schedule so that the majority of our seasonal customers who are currently on Schedule 83, many of whom operate for only a few months of the year, would not incur a Facilities Capacity Charge during the many months they do not consume energy. Instead, we used the volumetric distribution charge of Schedule 38 to allow these customers to receive billing for service that is contemporaneous with actual energy consumption. We chose the cutoff level of 200 kW so that the majority of seasonal customers would have the option of switching to Schedule 38. We contemplated changing the unusual on- and off-peak differentiated energy charges to a flat energy charge, but decided against this in order to not cause undue bill impacts to customers currently on Schedule 38.

Q. Do other facets to Schedule 38 merit consideration?

A. Yes. Consistent with cost causation principles, we believe that all Large Non-residential customers should have distribution-related monthly charges at least partially based on demand and facilities charges. However, we do make concessions and recover distribution costs on a volumetric basis for certain seasonal customer classes such as irrigators. To extend these concessions to large customers whose demand may approach 1,000 kW would violate these cost causation principles.

Additionally, unless a current Schedule 83 customer has a very low annual load factor, the relatively high Schedule 38 volumetric distribution charges will result in a larger bill for most Schedule 83 customers. Referencing PGE Exhibit 1303 page 1, proposed Schedule 38 base rates are approximately 9.5 cents/kWh while proposed Schedule 83-S base rates are approximately 7.4 cents/kWh. The decision to move from Schedule 83-S to Schedule 38 based on “the potential economic benefits of shifting load from peak to off-peak periods” (See COP/300, page 5) for most customers will likely result in a higher monthly bill.

Q. What do you recommend regarding the COP’s Schedule 38 proposal?

A. We recommend that the Commission reject the COP’s Schedule 38 proposal to further expand eligibility because we believe that we have achieved a reasonable approach to mitigating bill impacts to the majority of our seasonal customers by reopening Schedule 38 to customers whose demand does not exceed 200 kW. The COP proposal to further expand the eligibility to customers whose demand approaches 1,000 kW would violate cost-causation principles. Additionally, we question whether the COP understands the degree by which the Schedule 38 charges exceed Schedule 83 charges.

Q. Please discuss the service restoration priority issue raised by COP, COG, and LOC (the Cities).

A. The Cities propose that PGE modify its current service restoration policy (Rule C, section 8. pp. C-13 and C-14) in two ways. The Cities first propose that PGE should list "Protecting Public Safety" as the top priority. Second, the Cities propose that PGE maintain a specific list of "critical accounts" within each city that it serves and that a specific PGE representative be available to each individual city at all times. According to the Cities, this PGE representative "should also have a current list and address of all critical service facilities including city staff names and cell phone numbers or pager numbers." See COP/COG/LOC/200, page 5.

Q. What is PGE's response to the Cities' service restoration proposals.

A. Because the Cities did not propose specific modifications to the Rule C language, it is difficult to determine what needs to be changed. Within our current Rule C, we list "Protect Public Safety" as the top priority; hence we believe that our tariff needs no modification. Additionally, our Key Customer Account Managers currently provide the services that the Cities request. Once again, we believe that we are already providing what the Cities request. Absent the Cities providing specific language changes within Rule C, and identifying specific lapses in our current service to cities, we conclude that no changes in our service restoration policy are necessary.

Q. What do COP and COG recommend regarding the CIO?

A. COP and COG recommend that PGE reduce its proposed CIO from two times the average base rate increase to 1.5 times the average rate increase.

Q. Do you agree with the CIO proposal of COP and COG?

A. No. While we believe that it is important to mitigate large rate increases to certain schedules, we believe that it is more important to gradually move schedules closer to cost of service over time. Our CIO proposal accomplishes this better than the proposal of COP and COG.

III. Streetlighting Service

Q. Please identify the streetlighting issues raised by the Cities.

A. The Cities cite four streetlighting maintenance issues: 1) The overall streetlight O&M budget compared to the maintenance cost study estimate of streetlight maintenance derived from labor and facility specific estimates. The Cities refer to this as the "budget true-up" issue; 2) Projected repair frequencies; 3) Labor productivity assumptions; 4) Repair crew dispatch assumptions. The Cities also take issue with the following items not explicitly related to the Streetlight Maintenance Study: 1) Streetlight operating hours; 2) Metering of new Option C installations; 3) Customer-owned lights attached to PGE poles; and 4) Accounting and tracking of each individual streetlight circuit. Through these issues, the Cities seek to change the cost-causation and cost allocations used to establish streetlight rates. Below we discuss each of the items, commencing with the maintenance issues.

A. Streetlight Maintenance

Q. Before discussing each individual maintenance estimate item contained in the Streetlight Cost Study, would you please provide an overview of the Cities proposed overall level of adjustments to streetlight maintenance?

A. Through their four proposed adjustments, the cities propose to reduce PGE's test period maintenance costs for lighting services by $1.2 million, approximately 39%, to $1.9 million, a figure that is nearly 14% lower than the actual per light maintenance costs incurred in 2002. We base the $1.9 million resulting figure on the Cities Response to PGE Data Request No. 005, which is contained in the Pricing work papers. Additionally, the Cities incorrectly claim that PGE is proposing to increase Schedule 91 maintenance costs by

78.9% or nearly 16% annually from 2002 to 2007. They also incorrectly claim that Schedule 15 maintenance costs are proposed to increase by 100.7%, or 20% annually. See COP/COG/LOC/200, page 5.

Q. Could you please provide some perspective on the Cities proposed O&M reduction of $1.2 million for lighting services.

A. Yes. In its initial filing, PGE proposed total distribution O&M of $60.3 million, $3.1 million of which was for lighting services. Subsequent to this, PGE, OPUC Staff, CUB, ICNU, and Fred Meyer Stores reached a revenue requirement settlement that reduced distribution O&M by $1.6 million or approximately 2.7%. The testimony supporting this stipulation was filed with the Commission August 28. We believe that any adjustment to the proposed lighting O&M figure of $3.1 million should be commensurate with the stipulated reduction of 2.7%.

Q. Please evaluate the Cities' claim that maintenance costs for lighting services have increased by 80 to 100%.

A. The Cities cite PGE work papers 208, and 213 through 214, which demonstrate the increase in maintenance charges for various lighting options since UE 115. These figures, however, represent the amount of lighting services maintenance to which PGE and the Cities stipulated in UE 115, not the actual incurred maintenance. The actual amount of incurred maintenance in 2002 was significantly higher than the amount to which PGE stipulated ($2.15 million vs. $1.62 million).

Q. Would you please provide a more accurate representation of the amount by which lighting services maintenance has changed?

A. Yes. Table 1 below provides a more accurate picture of the amount by which actual lighting services maintenance has changed on a per unit year-to-year basis. Commencing with actual 2001 maintenance costs through 2005 plus estimates for 2006 and 2007, the table below demonstrates that the average per unit level of 2007 maintenance costs relative to 2001 has increased by 6.62% per year, nowhere near the annual levels claimed by the Cities in their testimony.

Table 1
Historical Lighting Maintenance Costs

Year	Maintenance Costs	Area & Option A & B Lights	Cost per light	Annualized Growth Rate
2001	$1,998,559	135,004	$14.80	
2002	$2,147,348	138,633	$15.49	4.63%
2003	$2,461,817	141,363	$17.41	8.46%
2004	$2,854,432	141,374	$20.19	10.90%
2005	$2,497,166	142,075	$17.58	4.39%
2006	$2,894,218	141,371	$20.47	6.70%
2007	$3,086,178	141,891	$21.75	6.62%

Q. Would you please provide recent inflation-adjusted annual per light figures and compare these figures to the test period per light maintenance figure?

A. Table 2 below compares the inflation adjusted maintenance figures for the years 2003 through 2005 to the 2007 test period on a per light basis. We used the fully loaded bargaining unit wage changes to express the historical maintenance costs in 2007 dollars. Exhibit 2201 contains the specific inflation adjustments. As Table 2 clearly shows, PGE's projected 2007 lighting maintenance projection is within the norms of recent historical experience. The projected 2007 per light cost of $21.75 is higher than that incurred in 2003 and 2005, but is lower than that incurred in 2004.

Table 2
Inflation Adjusted Lighting Maintenance: 2003-2005

Year	Maintenance Cost 2007 Dollars	Area & Option A & B Lights	Cost per Light 2007 Dollars
2003	$2,808,511	141,363	$19.87
2004	$3,163,014	141,374	$22.37
2005	$2,633,496	142,075	$18.54
Three-year average	$2,868,341	141,604	$20.26

Q. What do the Cities assert about the first maintenance adjustment to the Streetlight Cost Study, referenced in their testimony as the "budget true-up" issue?

A. The Cities mistakenly assert that PGE's overall streetlight O&M budget appears to be a "'place-holder', somewhat unrelated to projected maintenance expenses." See COP/COG/LOC/200, page 7. Because the Streetlight Cost Study estimates of labor and facility specific maintenance costs produce a maintenance figure approximately 9% lower than the overall budget, the Cities advocate using the lower figure.

Q. Do you agree with the assertions made by the Cities?

A. No. The overall streetlight O&M budget is not a "place-holder", but is rather a detailed budget that provides documentation supporting year-to-year cost changes by cost element and activity. This budget is in fact the target level of costs for streetlighting O&M. We use the Streetlight Cost Study to estimate costs on a per unit functional basis in order to send customers the correct price signal - not the absolute level of price. We compare these specific per unit cost estimates to the detailed budget and adjust the fixture specific costs to the budget on an equal percent basis; this process is the same we follow when we estimate functional marginal cost revenues and reconcile them to functional revenue requirement.

Q. What do you conclude regarding the Cities "budget true-up" issue?

A. We conclude that our method of projecting overall streetlight maintenance costs is appropriate because it results in the proper cost allocations, sends the correct price signal, and is superior to the Cities' proposed methodology which ignores actual budgets.

Q. What do the Cities recommend regarding the number of projected repair frequencies?

A. The cities recommend that streetlight repair frequencies should be based upon the first six or seven months of 2006 for two cities, Portland and Gresham, as opposed to the PGE methodology that utilizes data for all cities for the three-year period 2002 through 2004. The Cities claim that this methodology is superior to PGE's based on an assertion that the average age of PGE's streetlight system has fallen due to recent replacement of aging components and new installations accommodating load growth. They further assert that the streetlight system now has such a low average age that repair frequencies should fall by 40% from what they were only several years ago.

Q. Do the Cities provide any evidence for their assertion that the age of PGE streetlight system has fallen?

A. No, they provide no evidence that either the system has a lower average age or that such a system requires less maintenance. They only provide the six or seven months of repair frequency data for Portland and Gresham.

Q. How would the rate base amount and subsequently the investment revenue requirement portion of the Streetlight Cost Study be affected if PGE had replaced large portions of the streetlight system?

A. We expect that the investment portion of the Streetlight revenue requirement would increase. However, as pointed out in PGE work paper page 246, the investment portion for lighting schedules has actually decreased by 16.6% with PGE-owned luminaire investment decreasing by 20.7%.

Q. Please summarize the Labor Productivity issue.

A. The Cities urge reducing all streetlight maintenance labor inputs to reflect improved labor productivity. The Cities assert that, because PGE's streetlighting maintenance study shows large labor productivity improvements in portions of its streetlight maintenance study, all labor assumptions should commensurately reflect these productivity improvements.

Q. Do you agree with the Cities on this issue?

A. No. When PGE performs a Streetlight Cost Study it validates all previous inputs and estimates from prior cost Studies. In this docket PGE incorporated specific maintenance labor estimates to reflect recently achieved productivity improvements. Had PGE found increased productivity in the other labor inputs, corresponding adjustments would have been made to the Streetlight Cost Study.

Q. Please summarize the Crew Dispatch Issue.

A. Based on experience, PGE's Streetlight Cost Study recognizes that unique crew configurations perform different types of streetlight maintenance functions. In some cases three-person line crews perform the maintenance functions, while at other times dedicated lamp replacers or a single-person Eagle performs the maintenance. All three of the crews have different labor rates and PGE bases the cost of the particular maintenance function on a weighted average of the three crews. The Cities contend that PGE should include only the least cost crew (single-person Eagle) in the cost analysis. The Cities further contend that using only the least cost crew "is analogous to assuming least-cost dispatch of PGE's generators and market purchases to meet loads." See COP/COG/LOC/200, pages 12 and 13.

Q. Please evaluate the Cities' contentions.

A. The Cities appear either to misunderstand the nature of the tasks performed by the various types of crews, or believe that PGE has dedicated crews performing only streetlight maintenance. In either case, they are mistaken. A three-person line crew is responsible for all types of distribution maintenance, such as repairing or replacing line transformers or performing circuit maintenance. These line crews will perform the streetlight maintenance functions as part of their general distribution maintenance functions if they are being dispatched to a particular area and other types of crews are not available. The three-person line crew is the least-cost resource in these situations. The same is true of the relampers; they are at a particular point in time and for certain specialized functions, the least-cost resource.

Should the Cities wish for PGE to hire more Eagle crews and dedicate them to perform streetlight maintenance, the total cost of streetlight maintenance would undoubtedly increase.

B. Additional Streetlight Issues

Q. Please summarize the Streetlight Operating Hours issue.

A. The Cities contend that PGE should be required to reduce the annual hours of operation for streetlight luminaires from the current 4,150 to 3,995. The 4,150 operating hours is based on an April 1984 agreement between PGE and the City of Portland. This agreement was based on a study that utilized a base operating hours assumption of 4,200 hours with an allowance of 50 hours for outages. The Cities further propose that the Commission order PGE and the City of Portland to enter into a joint two-year study that would presumably determine the actual operating hours. The Cities base their operating hours arguments on:

1) a statement that the 1984 Study contemplated some manner of additional monitoring that has not taken place. See COP/COG/LOC/200 page 13. 2) PacifiCorp's 3,931 operating hours assumption for their Portland service territory; 3) the Cities calculation using data from the U.S. Naval Observatory, a manufacturers' photocell specifications, and a textbook reference that specifies the relationship between latitude and on/off times for photocells. From these calculations the Cities propose to deduct 50 hours per year for outages, citing the 1984 study whose conclusion they claim is no longer applicable.

Q. Did you evaluate the Cities' three arguments?

A. Yes. Regarding the 1984 study, the City of Portland during UE 1/UE 6, advocated using the Sigma Instruments, Inc. ten-year study. As mentioned above, this study resulted in the 4,150 street light burning hours that PGE has used for two decades. Within the 4,150 hours result of this study was an assumption of 4,200 burning hours with a 50 hour reduction for outages. The Cities wish to deduct these same 50 hours for outages, yet seemingly discredit all other portions of the study.

Regarding the argument that PGE should conform to PacifiCorp's assumed operating hours, we could easily make a similar case for adopting Puget Sound Energy's assumed operating hours of 4,200. It is not sufficient to change the operating hours assumption simply because another utility uses a different assumption.

The Cities' third argument may have some merit, but is incomplete. As mentioned above, the Cities use data from the U.S. Naval Observatory that demonstrates that the Portland area annually experiences approximately 4,300 hours of darkness. The Cities then adjust these hours of darkness downward based on an assumption that all streetlights go on 22 minutes after sunset and 19 minutes before sunrise. This assumption reduces the operating hours from the approximate 4,300 to 4,045. After this, the Cities further contend that another downward adjustment must occur, specifically the 50 hours for outages from the 1984 study to which both PGE and the City of Portland stipulated. Again, it was this stipulated study that resulted in the current 4,150 operating hours. Finally, the Cities admit in their response to PGE Data Request No. 002 that further adjustments may need to be made to their calculated figure of 4,045 based on Portland's weather. Unfortunately, the Cities do not specify what these "further adjustments" may be.

Q. What other factors besides hours of darkness may contribute to streetlight operating hours?

A. Factors that may increase the operating hours of streetlights include atmospheric conditions such as clouds, haze, and smog, photocell drift, nearby trees and "dayburners." Dayburners are especially important because PGE uses FAIL-ON photocontrols. According to the Illuminating Engineering Society of North America (IESNA), most U.S. lighting installations also use FAIL-ON photocontrols. In other words, failures are more likely to be dayburners rather than outages. IESNA recommends that dayburners add between 25 to 75 burning hours per year to a lighting system. PGE Exhibit 2202-C is the professional IESNA paper that contains this dayburner recommendation. We label this paper as confidential because of copyright concerns. The Cities did not consider any of these factors in their analysis.

Q. Have you conducted your own analysis of streetlight burning hours?

A. Yes. Starting with the sunrise and sunset tables for the 2007 test period and then with input from the IESNA document cited above and from data supplied by a photocell manufacturer, we calculated a total of 4,176 annual burning hours. Exhibit 2203 contains both the summary of the analysis and the supporting data from the photocell manufacturer.

Q. Please specify how your analysis that resulted in the 4,176 burning hours differed from that of the Cities'.

A. Generally, we started from the same data source as the Cities, the sunrise and sunset tables provided by the U.S. Naval Observatory. However we used the 2007 tables rather than the 2006 tables used by the Cities in order to be consistent with the 2007 test period. We then used the Cities' photocell specifications (turn-on to turn-off ratio of 1:1.5) at a latitude of 45 degrees to determine the number of minutes after sunset and before sunrise that the specified photocell should turn on and off. Dark to Light, Inc., one of PGE's photocell suppliers provided us their specifications of turn-on at 18 minutes after sunset and turn-off at 16 minutes before sunrise at a latitude of 45 degrees; this amounts to a difference of 7 minutes per day or about 43 hours per year from the Cities' unsupported calculations. We also note that page 12 of the IESNA document contained in Exhibit 2202-C supports these on/off values. We then used the midpoint recommendation of IESNA and added 50 hours per year for dayburners. In order to account for atmospheric conditions, we averaged the recommendations of IESNA (adding 5 minutes per cloudy day) and the midpoint of Dark to Light (adding 10 to 20 minutes per cloudy day) regarding per-day adjustments for cloudy days. This resulted in an average adder of 10 minutes per cloudy day, which we then multiplied by the average number of cloudy days in Portland (222 according to the Western Regional Climate Center.) All of our calculations and supporting documentation are contained in PGE Exhibits 2202-C and 2203.

Q. What do you conclude regarding the Cities' operating hours issue?

A. We conclude that the operating hours should be maintained at their current level of 4,150 hours or perhaps increased to 4,176. Our detailed calculations are supported by the analysis of both a photocell manufacturer and by lighting professionals. The Cities, on the other hand provided no evidence to support their claim that lights go on 22 minutes after sunset and 19 minutes before sunrise. When we asked them to provide their calculations for this assumption (COP/COG/LOC Response to PGE Data Request No. 002 attached as a portion of Exhibit 2203) they responded that they used a specific manufacturer's photocell specifications and information contained in a 1961 article published in an engineering journal. The Cities did not provide their calculations, nor did they provide the photocell specifications, nor the 1961 publication that formed the basis of their on/off assumptions. Furthermore, the Cities did not include in their analysis any factors that may increase the streetlight operating hours; they only included downward adjustments based on data from a study they ultimately disregard because of its conclusions, and from calculations which they have not provided.

Q. What issues do the Cities raise regarding the proposal to meter new Option C installations and bill them under the provisions of Schedule 32?

A. The Cities propose that PGE's proposal to meter new Option C lighting installations be rejected and that the Cities be allowed to switch their lights from Option B to unmetered Option C service. See COP/COG/LOC/200 page 14. The Cities' latter proposal would allow them to perform maintenance on customer-owned luminaires that are attached to PGE distribution poles, a practice that is not allowed under PGE's current and proposed tariffs.

The Cities assert that PGE's proposal to meter new Option C installations would cause problems for new large commercial and residential developments within the City of Portland because, according to the Cities, these new developments have requirements such that new lights "become Option C lights." See COP/COG/LOC/200 page 15. The Cities also assert that due to the Schedule 32 customer charges, they would be forced to accept PGE-provided maintenance for smaller lighting installations (one to several lights). The Cities further assert that PGE is attempting to "force the Cities to give up maintenance of streetlights" and that PGE is simultaneously attempting to overcharge for Option B maintenance, making this Option a "cash cow." See COP/COG/LOC/200, page 17.

Q. Do you agree with the Cities' assertions?

A. No. PGE has proposed to meter new Option C installations primarily because of the amount of energy diversion that occurs on Option C lighting installations. According to field personnel, energy diversion from lighting installations occurs predominantly with Option C lighting installations. Some examples are as follows:

1) We have experienced ongoing problems with one city that has added numerous Christmas lights and irrigation controllers to such a degree that they have repetitively caused faults in circuits. PGE eventually had to replace and upgrade a circuit to match the load, a portion of which consisted of energy diversion.

2) One of the cities informed us that they caught a customer recharging his electric car from an Option C installation by adding a receptacle at the handhole.

3) Field personnel have discovered numerous instances where irrigation controllers have tapped into Option C circuits.

4) Field personnel have discovered Option C installations where additional lights have been installed after the original installation, yet these additions were not reported to PGE.

In short, PGE would not be acting in a responsible manner with regard to all of its other 800,000 other customers if it allowed this problematic situation to continue.

Q. Why is it more difficult to discover energy diversion from an Option C installation as opposed to an Option A or B installation?

A. Because PGE does not provide the maintenance for Option C installations, it frequently is unable to monitor Option C activity and, therefore does not discover the energy diversion until long after it occurs, if at all.

Q. Are you aware of other utilities that have grandfathered pre-existing customer-owned lighting installations effectively requiring that new customer-owned lighting installations be metered?

A. Yes. Puget Sound Energy through its Schedule 54 has prohibited new unmetered customer-owned streetlighting installations since June 1, 1999.

Q. Please comment on the Cities' assertions that PGE is somehow hindering the City of Portland in its requirements that large subdivisions or developments install "what become Option C lights."

A. Our proposal allows for the City of Portland to meet its requirements for large developments; we only propose that these new large Option C installations be metered.

Q. Please comment on the Cities' assertions that PGE is attempting to force the Cities to give up maintenance.

A. Again, PGE is comfortable with the Cities performing maintenance on their lighting equipment installed on their poles; we only propose that new installations be metered. With metered service, the Company does not have to track the number and the wattage of lights installed. The Cities are then free to utilize the Option C lighting installation for purposes other than lighting.

Q. Please comment on the Cities' assertions that PGE overcharges for option B maintenance and that this maintenance is a "cash cow."

A. This is perhaps the Cities' most unsubstantiated assertion. As we pointed out earlier in our testimony, PGE stipulated in UE 115 to a level of maintenance that was approximately $500,000 per year lower than that incurred. The Cities have enjoyed a level of PGE maintenance that has been priced substantially below cost for the past five years. In this proceeding we are attempting to recover our prospective costs for providing this service. We have clearly documented that our prospective maintenance costs are consistent with recently incurred annual maintenance costs.

Q. What do you recommend regarding the metering of new Option C installations?

A. We recommend that the Commission adopt our proposal to meter new Option C installations. Our obligation to reduce energy diversion to the benefit of all of our customers far outweighs the concerns raised by the Cities.

Q. Please summarize the issue of customer-owned lights attached to PGE poles.

A. Currently PGE requires customer-owned and maintained lighting equipment (Option C) to be mounted on customer-owned poles. PGE does allow customer-owned lighting fixtures to be mounted on PGE distribution poles at no cost to the customer, but requires that PGE perform the maintenance on these fixtures at a regulated rate (Option B). By allowing customers to attach to PGE distribution poles at no cost, PGE provides an option that results in substantial capital cost savings to its streetlighting customers. The Cities argue that "PGE should permit municipalities to install, maintain, transfer, or remove consumer-owned lights mounted to PGE-owned distribution poles as long as the work is done by qualified personnel." See COP/COG/LOC/200, page 18. The Cities further contend that their proposal is "a generally accepted practice among electric utilities."

Q. Is it "a generally accepted practice" to allow customer maintenance of customer-owned fixtures on utility distribution poles?

A. No, because it is not necessarily "generally accepted practice" for electric utilities to allow streetlighting customers to mount customer-owned lighting fixtures on utility poles. Many electric utilities that we are aware of draw clear distinctions between customer-owned and maintained fixtures and utility-owned and maintained fixtures. These utilities assume the ownership and provide the maintenance for lighting fixtures attached to their distribution poles. Conversely, these utilities require that the streetlighting customer provide their own pole for lighting fixtures they wish to own and maintain. In this manner, the customer-owned facilities are more effectively isolated from the utility-owned facilities.

Q. Why should PGE retain maintenance responsibilities for lighting equipment attached to its poles?

A. PGE is responsible for the overall performance level of its distribution system and is accountable to the Commission should its performance fall below specified levels. Additionally, PGE could incur large fines for substandard performance. Because of this, PGE retains the maintenance functions for lighting fixtures mounted on its equipment. We cannot guarantee the work of contractors with whom PGE has no enforceable contract. While it is true that PGE hires contract crews to perform maintenance functions, these contract crews are paid by PGE and are held to PGE safety and performance standards. Furthermore, these crews work under PGE supervision.

Q. What do you conclude regarding this issue?

A. We conclude that our responsibility to provide reliable service to all of our customers in a manner that meets the service quality standards far outweigh the Cities' desire to perform maintenance on their lighting facilities attached to PGE equipment.

Q. Please describe the "Accounting" issue.

A. The Cities ask the Commission to require PGE to individually identify all PGE circuits that support streetlights and bill those lights only for these individually identified circuits. The Cities further contend, that because they do not understand the investment cost recovery factors and the depreciation study the Commission should require PGE to restate these factors and justify them.

Q. Please comment on the streetlight circuit issue.

A. The Cities suggest costly changes to PGE's tracking of distribution system costs, and in its accounting system. When PGE installs new distribution infrastructure that includes dedicated streetlight circuits, some of the costs are allocated to specific plant accounts based on historical experience.

This is the most effective means of building distribution infrastructure and allows PGE to more efficiently track plant in our accounting system. PGE wants its distribution field personnel to concentrate on building distribution infrastructure, rather than on recording individual streetlight circuits that in monetary terms comprise less than 1% of distribution plant.

Regarding the billing for streetlight circuits, the same cost conscious arguments as above apply. We charge all applicable customers the same amount for streetlight circuits; to do otherwise would require costly light-specific tracking and billing of over 130,000 streetlights. To put the Cities' arguments in perspective, it may be useful to consider how we bill our Schedule 7, Residential Service. We do not charge residential customers more if their service lateral is fifteen feet longer than their neighbors'. Instead, we set rates for all residential customers on a basis that does not individually track service lateral distances. 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.

Q. Please comment on the investment cost recovery portion of the Accounting issue.

A. We are somewhat confused regarding this issue. The Cities claim that the book depreciation rates seem high to them, but they make no specific recommendations as to what the depreciation rates should be. PGE's Depreciation Study was filed in Docket No. UM 1233 and the Cities had ample opportunity to participate in that docket.

IV. Partial Requirements

Q. Please describe how ICNU proposes to change the partial requirements service provided under Schedule 76R, Economic Replacement Power Rider (ERP).

A. ICNU has proposed the following three alternatives which would result in a new array of options for the Economic Replacement Power service: 1) Use the daily pricing options as proposed in Schedules 83/89; 2) Allow a 76R customer to receive service from an ESS in a manner similar to Schedule 576R; 3) Allow 76R customers to receive service under the provisions of Schedule 87, Experimental Real Time Pricing for their non-Baseline Demand load. The three ICNU alternative ERP supply arrangements would replace the current and proposed Schedule 76 ERP supply arrangements.

ERP service is an optional service that allows partial requirements customers to purchase power from the Company when the customer's on-site generation is otherwise available to serve the customer's load. ERP is thus an adjunct economic-based replacement power service to Schedule 75, Partial Requirements Service (which provides customers with a more traditional emergency standby service when the customer's generation is not operational).

Q. Describe the service provided by Schedule 76R, (ERP).

A. Our proposed Schedule 76R retains the current service allowing partial requirements customers to have an option to request that the Company purchase replacement power on the customer's behalf in lieu of operating on-site generation. With the ERP option, the customer may make a request to the Company for ERP with only 90-minute notice when it determines that economic factors warrant shutting down their on-site load-serving generation. The ERP request requires that the Company make an additional power purchase to support the customer's request. The pricing is hourly Mid-C indexed prices and includes a mark-up as well as costs associated with wheeling and losses. A settlement process handles any deviations between forecast and actual usage.

Q. Does the Company support ICNU's three alternative ERP supply options?

A. No. ICNU proposes to replace the current ERP service and add the new ERP pricing options, but does not explain many of the details about how the different options would function in practice. ICNU simply states that we should offer more options "consistent with what is available in the market."

ICNU does not explain how the specific proposals reflect market-available services that are useful and available for partial requirements customers' supply decisions. These services would typically require specific advance scheduling and pricing procedures and settlement processes. None of these requirements and details are discussed by ICNU. In addition, ICNU does not recognize that ERP is a customer-optional service provided by the Company as an additional service for partial requirements customers. As such, we believe the service should meet customer needs in reasonable, administratively and operationally feasible manner.

Q. Please explain your overall concerns with the ICNU's proposed ERP options.

A. We are concerned that the three new ERP options ICNU proposes are shotgun approaches to providing "marketing prices" to partial requirements customers. We are, as already stated, concerned that none of the proposals presented include details to thoroughly consider the specific requirements on both the customer and the Company in making such an option available. Indeed, it is not clear how the options could interact among themselves.

Q. Please review ICNU's proposed ERP options.

A. ICNUs' first proposal is to use the Schedule 83 and 89 daily pricing option for pricing ERP. This pricing option is based on reported daily Mid-C indexed heavy load and light load hours which are known only after the trading window for day-ahead firm transactions is essentially closed. This service does not provide advance price information sought by ICNU. When Schedule 76 was originally developed with significant customer and Staff input, price certainty was an important consideration. Finally, ERP is an entirely different type of service when compared to the Schedule 83 and 89 daily pricing option which supplies the on-going customers loads. ERP supply is an on-demand request for additional power to replace on-site generation based on economics. As such it potentially places PGE at significant risk for actually acquiring power at the index rate. The current Schedule 76 was developed with recognition of these risks.

ICNU also proposes to allow a Schedule 75 partial requirements customer to receive ERP service as a direct access customer. PGE has proposed direct access tariff schedules that enable a partial requirements customer to receive service from an ESS that are consistent with the direct access options that we provide the majority of our eligible customers. Specifically, if partial requirements customers expect that direct access service is beneficial, the combination of Schedule 575 and 576 provide the complete service package. The split service option (Partial Requirements provided by PGE under Schedule 75 and ERP provided by an ESS) is not fully developed by ICNU. In the short time since we received ICNU's testimony, we have not had an opportunity to fully consider all of the systems and operational ramifications of such a regime.

Finally, ICNU proposes to use the pricing structure in Schedule 87 to provide day-ahead pricing for ERP. Schedule 87, Experimental Real-Time Pricing Service, is a limited participation, experimental schedule intended to test the impact of real-time pricing on non-partial requirements loads. The pilot schedule itself does not allow nor is it designed to accommodate ERP for a partial requirements customer. Further, there is no day-ahead hourly market that we can use for RTP pilot price quote purposes, so we must synthesize hourly day-ahead prices by shaping the day-ahead Mid-C prices based on historical information. Again, it places PGE at significant risk in order to allow the customer to trade-off self-generation costs and market costs

Q. What is your conclusion regarding the ICNU proposal on Schedule 76R?

A. ICNU has not shown that their proposed ERP options will result in both manageable and useful services that we should be required to provide. Each of the proposed options is incomplete and leaves many operational details unknown. We do not believe that the development of more pricing options that are not carefully evaluated for both costs and value is useful to the overall provision of service. The Company is willing to continue with its current Schedule 76R service to partial requirements customers.

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2201	PGE Inflation Adjusted Per Light Maintenance
2202-C	**(Confidential – Provided under separate cover)** **IESNA Subcommittee Report**
2203	PGE Streetlight Burning Hours Analysis

	O&M	lights	per unit Cost
2001	$1,998,559	135,004	$14.80
2007	$3,086,178	141,891	$21.75
			46.93%
			6.62%

Year	Amount	Lights	Per Unit	Percent Change	Growth	Average Growth
2001	$1,998,559	135,004	$14.80			
2002	$2,147,348	138,633	$15.49	4.63%	4.63%	4.63%
2003	$2,461,817	141,363	$17.41	12.43%	17.64%	8.46%
2004	$2,854,432	141,374	$20.19	15.94%	36.39%	10.90%
2005	$2,497,166	142,075	$17.58	-12.95%	18.73%	4.39%
2006	$2,894,218	141,371	$20.47	16.48%	38.29%	6.70%
2007	$3,086,178	141,891	$21.75	6.24%	46.93%	6.62%

PORTLAND GENERAL ELECTRIC
Inflation Adjusted per Light Maintenance: 2002-2007

Year	Direct Labor Bargaining	2002 Index	Labor Loadings	Loaded 2002 Index	2007 Index	Nominal Maintenance	2007 Dollars Maintenance	Lights	Current Maintenance per Light
2002	4.00%	100.00%	72.28%	172.28%	82.34%	$2,147,348	$2,607,935	138,633	$18.81
2003	4.00%	104.00%	76.35%	183.40%	87.66%	$2,461,817	$2,808,511	141,363	$19.87
2004	1.00%	105.04%	79.76%	188.82%	90.24%	$2,854,432	$3,163,014	141,374	$22.37
2005	3.00%	108.19%	83.38%	198.40%	94.82%	$2,497,166	$2,633,496	142,075	$18.54
2006	3.00%	111.44%	81.32%	202.06%	96.57%	$2,894,218	$2,996,992	141,371	$21.20
2007	3.00%	114.78%	82.29%	209.23%	100.00%	$3,086,178	$3,086,178	141,891	$21.75
Three-year totals: 2003-2005							$8,605,022	424,812	$20.26

Note: source of bargaining percents is PGE 900/ page 6
and PGE PGE 200/ page 2

Portland General Electric
Labor Loading Rates

C_E		Labor CE's Affected	Loadings Allocated to	2002 Budget	2002 Actuals	2003 Budget	2003 Actual	2004 Budget	2004 FINAL	**2005 Budget**	**2005 FINAL**	**2006 Budget**	**2006 Budget REVISION**	**2007 Budget (prelim)**
93	**Vacation (PTO)**	11	All ledgers	16.67	18.48	17.13	18.25	17.07	17.79	16.59	17.62	17.25	17.25	17.13
94	**Employee Benefits (b)**	11	B/S & BTL *	20.38	22.99	24.52	25.53	24.59	28.70	31.41	31.10	29.63	29.63	30.44
95	**Payroll Taxes**	11, 12, 16, 17	B/S & BTL	10.50	10.35	10.50	10.56	10.50	10.19	10.50	10.53	10.50	10.50	10.50
96	**PGE I&D (PGE Only)**	11, 12, 16, 17	B/S	7.40	6.34	7.35	5.72	8.99	6.61	7.83	7.68 (b)	7.44	7.44	7.00
91	**Incentives (PGE Only)**	11	B/S & BTL	6.46	4.60	4.55	5.63	6.43	4.77	5.19	4.67	5.30	5.30	5.20
88	**Pension Service Cost (a)**	11	I/S & BTL	6.39	6.29 (3)	6.52	7.34	8.57	8.26	7.27	8.23	9.02	8.24	9.03
89	**Employee Support**	11	B/S & BTL	3.10	3.23	3.05	3.32	3.11	3.44	2.99	3.55	2.96	2.96	2.99
	All Labor Loadings			70.90	72.28	73.62	76.35	79.26	79.76	81.78	83.38	82.10	81.32	82.29
	Product Loadings (excludes ce 96 PGE I&D)			63.50	65.94	66.27	70.63	70.27	73.15	73.95	75.70	74.66	73.88	75.29
	Removal of PTO loading if using loadings against annual salary			46.83	47.46	49.14	52.38	53.20	55.36	57.36	58.08	57.41	56.63	58.16
	Capital (excludes ce 88, Pension Service cost)			64.51	65.99	67.10	69.01	70.69	71.50	74.51	75.15	73.08	73.08	73.26

Note: Prior years may be hidden in file and not printed.
Note: revision percentages apply to full year. All prior actuals in stated year are re-calced with the new percentages.

* - BTL is "below the line"
(b) Increase in rate is due to higher claims

PORTLAND GENERAL ELECTRIC
STREET AND AREA LIGHT BURNING HOURS

Hours of Darkness	4,296
Deduct 18 minutes for Turn-ON	(110)
Deduct 16 minutes for Turn-OFF	(97)
Subtotal	4,089
Add 50 hours for dayburners	50
Add 10 minutes per cloudy day (222 days)	37
Total Portland Burning Hours	4,176

o , o ,
Location: W122 39, N45 31 PORTLAND, OREGON
Pacific Standard Time

Astronomical Applications Dept.
U. S. Naval Observatory
Washington, DC 20392-5420

Duration in Minutes of Darkness for 2007

Day	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.		
1	913.00	855.00	772.00	673.00	582.00	513.00	503.00	555.00	643.00	737.00	832.00	901.00		
2	912.00	852.00	769.00	670.00	579.00	512.00	503.00	558.00	646.00	741.00	835.00	903.00		
3	911.00	850.00	766.00	666.00	576.00	511.00	504.00	560.00	649.00	744.00	838.00	904.00		
4	910.00	847.00	762.00	663.00	574.00	509.00	505.00	563.00	652.00	747.00	840.00	906.00		
5	909.00	844.00	759.00	660.00	571.00	508.00	506.00	565.00	655.00	750.00	843.00	907.00		
6	908.00	841.00	756.00	657.00	568.00	507.00	507.00	568.00	659.00	753.00	846.00	908.00		
7	906.00	838.00	753.00	654.00	566.00	506.00	508.00	571.00	662.00	756.00	849.00	910.00		
8	905.00	836.00	750.00	651.00	563.00	505.00	510.00	573.00	665.00	759.00	851.00	911.00		
9	904.00	833.00	747.00	647.00	560.00	504.00	511.00	576.00	668.00	763.00	854.00	912.00		
10	902.00	830.00	743.00	644.00	558.00	503.00	512.00	579.00	671.00	766.00	857.00	913.00		
11	901.00	827.00	740.00	641.00	555.00	502.00	514.00	581.00	674.00	769.00	859.00	913.00		
12	899.00	824.00	737.00	638.00	553.00	502.00	515.00	584.00	677.00	772.00	862.00	914.00		
13	897.00	821.00	734.00	635.00	551.00	501.00	517.00	587.00	680.00	775.00	864.00	915.00		
14	896.00	818.00	730.00	632.00	548.00	501.00	518.00	590.00	684.00	778.00	867.00	916.00		
15	894.00	815.00	727.00	629.00	546.00	500.00	520.00	593.00	687.00	781.00	869.00	916.00		
16	892.00	812.00	724.00	626.00	544.00	500.00	521.00	595.00	690.00	784.00	871.00	917.00		
17	890.00	809.00	721.00	623.00	541.00	499.00	523.00	598.00	693.00	787.00	874.00	917.00		
18	888.00	806.00	718.00	620.00	539.00	499.00	525.00	601.00	696.00	791.00	876.00	917.00		
19	886.00	803.00	714.00	617.00	537.00	499.00	527.00	604.00	699.00	794.00	878.00	918.00		
20	884.00	800.00	711.00	614.00	535.00	499.00	529.00	607.00	703.00	797.00	881.00	918.00		
21	882.00	797.00	708.00	611.00	533.00	499.00	531.00	610.00	706.00	800.00	883.00	918.00		
22	879.00	794.00	705.00	608.00	531.00	499.00	533.00	613.00	709.00	803.00	885.00	918.00		
23	877.00	791.00	702.00	605.00	529.00	499.00	535.00	616.00	712.00	806.00	887.00	918.00		
24	875.00	788.00	698.00	602.00	527.00	499.00	537.00	619.00	715.00	809.00	889.00	918.00		
25	872.00	785.00	695.00	599.00	525.00	499.00	539.00	622.00	718.00	812.00	891.00	917.00		
26	870.00	781.00	692.00	596.00	523.00	500.00	541.00	625.00	722.00	815.00	893.00	917.00		
27	868.00	778.00	689.00	593.00	521.00	500.00	544.00	628.00	725.00	818.00	895.00	917.00		
28	865.00	775.00	685.00	590.00	520.00	501.00	546.00	631.00	728.00	821.00	896.00	916.00		
29	863.00	0.00	682.00	587.00	518.00	501.00	548.00	634.00	731.00	823.00	898.00	916.00		
30	860.00	0.00	679.00	585.00	516.00	502.00	551.00	637.00	734.00	826.00	900.00	915.00		
31	858.00	0.00	676.00	0.00	515.00	0.00	553.00	640.00	0.00	829.00	0.00	914.00		
Minutes of Darkness	27576.00	22850.00	22444.00	18836.00	16904.00	15079.00	16236.00	18483.00	20653.00	24306.00	26063.00	28320.00		Avg
Hours of Darkness (Proposed)	**459.60**	**380.83**	**374.07**	**313.93**	**281.73**	**251.32**	**270.60**	**308.05**	**344.22**	**405.10**	**434.38**	**472.00**	**4295.83**	**358.0**

DTL
DARK TO LIGHT

Sunrise/Sunset Times for Latitude 45
Streetlight Burning Hours with Electronic Controls

USA cities at this latitude: Minneapolis, MN (44.9)
Alpena, MI (45.1)
Burlington, VT (44.5)

Hours of daylight (365 day year):	4463 hours	57 minutes
Hours of twilight and darkness:	4296	3

Photocontrol assumptions:

Photocontrol assumptions: Turn-ON 1.00 ftc --> 18.0 minutes after sunset

34

Turn-OFF 1.50 ftc --> 16.0 minutes before sunrise

Luminaire burning hours: under ideal conditions i.e., no cloudy or smog days and no dayburners	4089 hours	53 minutes

Adders for Electronic Controls

1) dayburners	7	
2) clouds/smog	25	
3) drift	0	
	4121 hours	53 minutes

DTL
DARK TO LIGHT

Streetlight Burning Hours Analysis

Latitude 45

This Attachment examines streetlight burning hours for latitude 45. Pages 3 and 4 of this Attachment are analyses of streetlight burning hours for the Latitude 45 area using a computer program which DTL wrote for this purpose. These results can be combined with other DTL software to demonstrate, clearly and concisely, the costs and benefits of different streetlight and photocontrol assumptions. The results may be useful in tariff applications.

For a given photocontrol's turn ON value and OFF/ON ratio, streetlight burning hours are primarily latitude dependent. (Total annual daylight hours only vary by about 20 hours from northern to southern U.S.--with more daylight in the north.) All time data are taken from Tables of Sunrise, Sunset, and Twilight., United States Naval Observatory, Washington, D.C. 1962.

1. Burning Hours with Conventional Controls: Exhibit 1

   One analysis shows luminaire burning hours assuming a commodity (AC relay or thermal) photocontrol with a turn-ON of 1.0 ftc and nominal turn-OFF of 3.0 ftc. With these OFF/ON values, at latitude 45 annual burning hours per streetlight would be about 4,118 hours.

   This basic analysis makes no allowance for dayburners, atmospheric conditions or drift--with commodity controls (AC relay, thermal), these factors are significant and adjustment should be made. The impact of dayburners is easily seen. If you allow 12.5 hours/day of extra burning for a dayburner, and you assume that 5 to 10 % of your controls fail each year and dayburners burn 60 days before they are fixed, (all very common values), then you need to add 37 to 75 hours per streetlight for dayburners.

   Clouds, haze, fog and smog also add to burning hours--e.g., say 10 to 20 minutes per cloudy day. As a guess, you might want to add 25 hours or so for atmospheric effects (assumes about 30% of days are affected).

   Finally, photocell drift also generally increases burning hours. In non-electronic, "old-style" AC relay or thermal controls, photocells are often over-powered and effectively

NUMBER OF CLEAR DAYS (ENTIRE UNITED STATES)
(First Order Stations Only)

Greatest Number of Clear Days		Least Number of Clear Days	
1. Yuma, AZ	242	1. Elkins, WV	48
2. Phoenix, AZ	211	2. Astoria, OR	50
3. Las Vegas, NV	210	3. Quillayute, WA	51
4. Sandburg, CA	208	4. Binghamton, NY	52
5. Bishop, CA	201	5. Olympia, WA	52
6. Fresno, CA	194	6. Buffalo, NY	54
7. El Paso, TX	193	7. Burlington, VT	58
8. Tucson, AZ	193	8. Seattle, WA	58
9. Bakersfiled, CA	191	9. Caribou, ME	59
10. Sacramento, CA	188	10. Pittsburgh, PA	59

NUMBER OF CLOUDY DAYS (ENTIRE UNITED STATES)
(First Order Station Only)

Greatest Number of Cloudy Days		Least Number of Cloudy Days	
1. Astoria, OR	239	1. Yuma, AZ	52
2. Quillayute, WA	239	2. Phoenix, AZ	70
3. Olympia, WA	228	3. El Paso, TX	72
4. Seattle, WA	226	4. Las Vegas, NV	73
5. Portland, OR	222	5. Los Angeles-Downtown,CA	73
6. Kalispell, MT	214	6. Bishop, CA	75
7. Binghamton, NY	212	7. Sandburg, CA	78
8. Elkins, WV	212	8. Santa Maria, Ca	80
9. Beckley, WV	210	9. Alamosa, CO	81
10. Eugene, OR	209	10. Tucson, AZ	81
11. Sault Ste. Marie, MI	209		

CITY OF
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August 25, 2006

TO: Patrick G. Hager
Manager, Regulatory Affairs
Rates & Regulatory Affairs
Portland General Electric Company
121 SW Salmon St., 1WTC0702
Portland, OR 97204

PGE.OPUC.Filings@pgn.com

FROM: Benjamin Walters, Senior Deputy City Attorney BW
City of Portland
City Attorney's Office

PORTLAND GENERAL ELECTRIC
UE 180/UE 181/UE 184
Response to PGE's First Set of Data Requests to COP/COG/LOC
Dated August 16, 2006
Question Nos. 001-004

The City of Portland, the City of Gresham and the League of Oregon Cities provide the answers set forth below in response to PGE's data requests 1-4, issued on August 16, 2006.

Request:

1. **Please provide work papers in support of the basis for photocell operation (turn-on 30 minutes after sunset, turn-off 30 minutes before sunrise) included in the streetlight operating hours of 3,931 for PacifiCorp found on Exhibit COP/COG/LOC/213. Please provide the work papers electronically with all formulae intact.**

   Response: The information contained in Exhibit 213 was provided to the City of Portland by PacifiCorp, regarding the data used by PacifiCorp in computing annual street lighting burn hours. PacifiCorp uses the US Naval Observatory's annual sunrise/sunset data as a base. They then assumed that the lights turn on 30 minutes after sunset and turn off 30 minutes before sunrise. The net result is a calculation of 3,931 hours. See attached spreadsheet, UE 180 COP/COG/LOC/213.xls. This spreadsheet is being provided to PGE in exactly the same form in which it was received from PacifiCorp.

2. **Please provide work papers in support of the basis for photocell operation (turn-on 22 minutes after sunset, turn-off 19 minutes before sunrise) included in the streetlight operating hours (before outages) of 4,045 proposed in testimony COP/COG/LOC/14. Please provide the work papers electronically with all formulae intact.**

   Response: See attached spreadsheet, UE 180 COP/COG/LOC/214.xls. An accurate calculation of street lighting burn hours requires three things:

   - Accurate sunrise/sunset data for the location,
   - Specifications for the particular photocell's on/off lighting levels, and
   - Latitude effects on twilight hours and footcandle levels.

   The sources referred to in assembling the above data were:

   - For sunrise/sunset data, the US Naval Observatory's sunset/sunrise data for Portland, Oregon.
   - For photocell on/off levels, the City of Portland's photocell specifications. In addition, the spec sheet for the Fisher Pierce photocell FP-7670C was used.
   - The correlation between latitude, light level and time relative to sunset or sunrise is based on "Photoelectric Controls for Street Lights", Howell, E.K., Electrical Engineering, Oct 1961, pp 780-785.

   The specifications for photocells requires turn-on at 1.0 footcandles +/- 0.3 footcandles. Turn-off shall be no greater than 1.5 times the turn-on lighting level. Based on these on/off lighting levels and using the resources noted above, our calculations predict a turn-on delay of 22 minutes after sunset and a turn-off delay of 19 minutes before sunrise. These values convert to 4,045 annual street lighting burn hours. The on/off times are calculated for clear skies. Further adjustments may be required for Portland's weather.

3. **Please provide the work papers, analysis and repair data for the first six and/or seven months of 2006 supporting the recommended 40% reduction in repair frequencies to all repair activities as stated in testimony found on COP/COG/LOC/10, lines 4 through 12. Please provide the work papers electronically with all formulae intact.**

   Response: See attached spreadsheet, UE 180 COP/COG/LOC/210.xls, and click "ignore" when Excel asks about updating linked files. The single linked file was received from PGE as MAINT_2007_Case_2007_Labor_PD.xls, which was Attachment A to PGE's response to COP/PGE-003. Additionally, Attachment 03-A contains the City of Portland's 2006 monthly repair reports. Attachment 03-B contains the City of Gresham's 2006 monthly repair reports.

4. **Please provide the work papers, analysis and basis for the recommendation to extend the productivity increases to the remaining 4 out of the 8 work elements as stated in testimony found on COP/COG/LOC/11, lines 12 through 17. Please provide the work papers electronically with all formulae intact.**

   Response: There are no additional work papers. The analysis and basis are contained in the testimony set forth in COP/COG/LOC/200. In addition, COP/COG/LOC observed that substantial productivity increases have been achieved regarding some but not all repair tasks, and have concluded that PGE can and should reasonably extrapolate those increases to other repair tasks, given that (a) the specific productivity increases were achieved by PGE staff (and perhaps contract staff), (b) the same PGE staff (and perhaps contract staff) perform the other repair tasks where productivity increases were not estimated or predicted, and (c) PGE has the direct responsibility to oversee the specific duties of its employees and contract staff, to assure maximum productivity.

Attachments:

UE 180 COP/COG/LOC/213.xls
UE 180 COP/COG/LOC/214.xls
UE 180 COP/COG/LOC/210.xls
UE 180 COP/COG/LOC/Attachment 03-A
UE 180 COP/COG/LOC/Attachment 03-B

Table of Contents

I. Introduction and Cost Update

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 address the issues identified by the Citizens' Utility Board (CUB) and the OPUC Staff (Staff) in relation to PGE's advanced metering infrastructure (AMI) project. We also provide an update of AMI capital and related operating costs.

Q. What is the current status of PGE's AMI project?

A. The current plan and timeline for the project are as follows:

- Complete negotiations with the selected AMI technology vendor by year-end 2006.
- Review bids, select a contract meter installer (CMI), and complete negotiations by year-end 2006.
- Conduct systems acceptance testing (SAT) for meters, network, and associated systems during the first and second quarters of 2007.
- Begin full deployment of AMI meters and network in the third or fourth quarters of 2007.
- Complete full deployment by year-end 2009.

PGE is currently developing detailed implementation plans for the creation of processes to derive the benefits identified in the business case. Plans to implement these processes should be completed by year-end 2006.

Q. Has PGE prepared an update of its analysis of AMI-related costs and benefits as filed on March 15, 2006?

A. Yes. Although PGE is still in the process of reviewing its AMI-related costs and benefits, we provide a summary of our AMI analysis based on current estimates of capital and related O&M costs. As noted above, PGE will not have completed final negotiations with an AMI meter vendor and CMI until year-end 2006, at the earliest. Consequently, final estimated costs will not be available until that time. PGE will provide a detailed and more current update, however, by October 1, 2006, as a supplemental response to OPUC Data Request No. 374.

Q. What is your current estimate for AMI system costs?

A. Based on current estimates, we believe the initial system investment will cost approximately $125 million over a 2007 to 2009 deployment period. This compares to the initial $141 million estimate in PGE Exhibit 800 (direct testimony, filed March 15, 2006). Exhibit 2301-C summarizes the projected AMI capital cost components. Current meter estimates are based on prices provided by the meter vendor selected through PGE's RFP process. As noted above, negotiations to finalize meter prices and CMI costs will not be completed until year-end 2006, at the earliest. Our current estimates assume the meters will almost entirely have radio frequency (RF) communication modules, with collectors, and a small number of meters with phone communication modules.

Q. Based on updates to O&M expenses, what is your current estimate for operational savings?

A. PGE has continued to review O&M assumptions in our analysis and based on these updates, we currently project O&M savings in 2010 to be approximately $16 million (see Table 1, below).

Q. Why is this less than your previous estimate in PGE Exhibit 800?

A. The $1 million decrease in savings is almost entirely based on changes in assumptions related to labor and wages plus associated labor loadings (updates to various non-labor components currently tend to offset each other). As noted above, PGE is continuing to evaluate AMI's O&M costs and assumptions and will provide a final estimate on October 1, 2006.

Table 1
Projected Annual O&M Savings - 2010

AMI Projected Savings	**($Million)**
Labor Cost	10.2
Non-labor Cost	0.9
Late Fees	1.7
Energy Unaccounted For	1.9
Power Cost Savings	1.4
Other Savings	-0.1
Total Projected Savings	**16.1**

Q. What other updates have you made to your analysis?

A. We have revised our analysis to remove the assumption that the remaining book value of the AMI system would be written off at the end of the 20-year period.

Q. Why did you eliminate this assumption?

A. PGE has been moderately conservative in its assumptions so as to not bias the analysis to an overly favorable result. One of those assumptions was that by the year 2026, the currently proposed system would be at the end of its useful life and ready to be replaced with a new system. After further consideration, we do not believe that incorporating this write-off is appropriate for the following reasons:

- The status quo system does not assume any write-off; making such an assumption for the AMI system would be inconsistent.
- The net present value (NPV) of the proposed AMI system is already burdened with the write-off of a system – the status quo system.
- With an 18-year life assumed for the proposed AMI meters, a significant amount of replacement costs are already included in the analysis.

Because of these considerations, we currently believe the assumption to write off the proposed system at the end of 20 years to be unnecessarily conservative.

Q. How do these changes affect the NPV of the project?

A. The NPV increases from $4.4 million to approximately $20 million assuming a deferral is authorized for this project, which represents a net overall decrease in revenue requirement over 20 years beginning in 2007. The approximate impacts described above are as follows:

- Approximately $4 million increase in NPV is due to the decrease in capital costs which outweighs the reduction in O&M savings.
- Approximately $12 million increase in NPV is due to the elimination of the AMI system write-off assumption at the end of the 20 years.

II. Staff Issues

Q. Can you briefly describe Staff's recommendations regarding PGE's AMI proposal?

A. Yes. As a preliminary matter, we note that Staff believed PGE was requesting pre-approval of the project, which Staff claims the Commission does not authorize. In fact, we were not requesting pre-approval. We address this concern in PGE's reply to CUB's issues in Section III, below. Staff made the following recommendations with regard to PGE's AMI proposal:

- PGE should make a supplemental tariff filing for the proposed accelerated write-off of non-AMI meters, with termination if full deployment is not implemented.
- PGE should file final costs for the AMI system based on results from the company's RFPs for meters and CMIs.
- PGE should file a deferral application and establish a balancing account for the revenue requirement of the AMI system less O&M savings throughout the deployment period.
- PGE should file a detailed implementation plan for the O&M benefits that the company reasonably expects to achieve.
- PGE should coordinate its AMI implementation with NW Natural (NWN) to minimize meter reading costs in the joint meter reading area.

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

A. PGE agrees to provide all of the filings and applications requested above and we agree to coordinate with NWN to minimize costs to customers.

Q. How will PGE coordinate with NWN in the design and implementation of a robust AMI system?

A. PGE meets with NWN on a periodic basis to discuss the joint meter reading agreement, concerns with the agreement, and performance under it. We also include issues regarding future plans as part of those discussions and will continue to work cooperatively. PGE plans to share information regarding our AMI vendor to facilitate the opportunity for NWN to use similar technology in the joint meter reading area. Should use of PGE's vendor not be economically or technologically viable for NWN, they still have the opportunity to install an automated meter reading (AMR) system in the joint area. In fact, through July 2006, NWN has deployed approximately 6,500 AMR meters within the joint meter reading area, at an approximate rate of 1,000 to 1,500 meters per month. Based on this, it appears that: 1) NWN plans to deploy their AMR system within the joint meter reading area at some point in the future, dependent on PGE's timing with AMI deployment, or 2) NWN's AMR deployment could surpass PGE's AMI deployment, which would require bilateral coordination between NWN and PGE in order to minimize costs for both companies.

III. CUB Issues

Q. Can you briefly describe CUB's opposition to PGE's AMI proposal?

A. Yes. CUB opposes PGE's AMI proposal for the following reasons:

- PGE's request for Commission "pre-approval," based on estimated costs that were not included in PGE's test year revenue requirement, "is a little bizarre."
- The NPV of the project is not sufficiently favorable.
- PGE had not effectively researched NW Natural's plans regarding deployment of their AMR system in the joint meter reading area.
- PGE is replacing UE 115 NMR meters with UE 180 AMI meters.
- PGE has not fully accounted for other utilities' analyses of AMI.
- Neither PGE nor state regulators have evaluated load control programs.
- CUB believes implementing an AMI system will lead to mandatory time-of-use pricing.

Q. Did PGE request pre-approval of its AMI proposal?

A. No. PGE did not request "pre-approval" of its AMI proposal. We did, however, request two things, neither of which is particularly "bizarre." First, as CUB noted, PGE requested "that the Commission find *that the decision to proceed* with deployment of an AMI system is reasonable and prudent at this time" (PGE Exhibit 800, page 1, italics added for emphasis). This does not suggest that PGE is either requesting a blank check for AMI or the elimination of a prudence review after the project is completed. Because AMI represents a $125 million investment, it is not unreasonable for PGE to ask the Commission to acknowledge that the move to AMI technology is correct at this time.[1] It would, however, be unreasonable for PGE to proceed with full deployment of AMI, without this acknowledgement, only to be informed in a subsequent rate case that the system was entirely inappropriate and all costs are disallowed from the company's revenue requirement. Ultimately, we believed the parties would appreciate the opportunity to address such an issue in advance, rather than after the fact.

Q. What is the second item PGE requested from the Commission?

A. PGE requested "Commission approval of the ratemaking treatment we propose for AMI-related costs. This proposal includes a deferral of the revenue requirement for capital costs and O&M savings resulting from AMI installation" (PGE Exhibit 800, page 1). We based this request on the fact that there is more than one rate-making alternative available for AMI costs. A deferral would reduce the rate impact in early years but increase it in later years. The alternative is to increase rates in the test year by a greater amount and have a lesser impact in later years. Because this choice involves a decided trade-off, PGE requested that the Commission indicate its approval of the deferral alternative (assuming a favorable response to PGE's request for Commission acknowledgement of the AMI system, as described above).

Q. How do you respond to CUB's concerns that PGE used estimated costs for its AMI analysis and proposal?

A. Because PGE's rate cases are always based on test years, we invariably use estimated costs in our revenue requirement. This not only relates to O&M expenses but also rate base costs

[1] PGE is referring to an acknowledgement similar to that received for Port Westward in Commission Order No. 04-375, Docket LC 33.

to be incurred each year, from the year of our most recent actual results through the test year.

Q. Does PGE plan to update its AMI cost estimates?

A. Yes. PGE is currently in the process of selecting and/or negotiating with AMI meter vendors and CMIs, and we are establishing more accurate cost estimates as we complete this stage of the project. We agree to provide a detailed cost update on October 1, as a supplemental response to OPUC Data Request No. 374. Our current estimates are listed in Section I, above.

Q. How do you address CUB's concerns that PGE will say that "We did not even include this in our rate filing, but the Commission believed it to be prudent and ordered us to implement it"?

A. CUB has no basis for this speculative assertion. We believe that given the record we are establishing in this proceeding, it would be disingenuous for PGE to make such a claim in the future, and we have no intention of doing so.

Q. Do you agree with CUB's claims that the AMI project has insufficient NPV to justify its implementation?

A. No. We agree that the costs and benefits, as calculated in our initial analysis, do not produce a large NPV. However, our updated costs and assumptions reflect a more favorable result, as described above. In addition, as we stated in PGE Exhibit 800 and in numerous responses to Staff and CUB Data Requests, all potential benefits from the system were not included in our initial analysis.

Q. What benefits did you not include in your initial AMI analysis?

A. PGE did not include secondary benefits such as demand response programs (e.g., critical peak pricing and load control) and grid management. As discussed in PGE Exhibit 800, PGE's proposed AMI system would set the platform for these benefits, but they will need to be developed in the future and would involve additional costs and investment.

Q. Have you included any of these benefits in your updated analysis?

A. No. Our analysis continues to include only the primary benefits directly available from the system as it is currently proposed and which we reasonably expect to achieve. PGE is still evaluating these secondary programs to identify their potential timing and scope plus an estimated range of incremental costs and benefits.

Q. When and how does PGE plan to submit details for these benefits?

A. Following Staff recommendations, PGE will submit a detailed implementation plan prior to year-end 2006, for the primary benefits we are designing the proposed system to achieve (see Staff Exhibit 700 for a description of the detailed implementation plan). These are the financial benefits we include in our current analysis. PGE also plans to submit a scoping plan for secondary benefits, such as demand response programs and grid management, which the proposed system enables but which will require additional costs and investment. Due to the complexity of evaluating the secondary benefits, PGE will develop the scoping plan during 2007. PGE will also provide a preliminary assessment of approximate ranges for costs and benefits related to scoping-plan items by year-end 2006.

Q. CUB questions PGE's original analysis because it reflected two versions – one with 21 additional meter readers and one without the additional meter readers – based on NWN's decision regarding their AMR deployment. Does your current analysis include additional meter readers?

A. No. We now understand that NWN will not deploy their AMR system absent any change to the joint meter reading arrangement with PGE. Consequently, PGE's current analysis consists of no new meter readers in the status quo scenario.

Q. Did PGE ask NWN about this during your initial analysis?

A. Yes. We did ask NWN about their AMR deployment plans in the joint meter reading area. This was particularly relevant because NWN is not only actively deploying AMR meters outside the joint meter reading area but, as noted in Section II above, NWN is deploying AMR meters within the joint meter reading area, albeit at new locations. At the time we asked NWN, which was prior to our filing, their response was non-committal. As a result, we filed our testimony and analysis with both possible cases. Several months later, when CUB asked NWN the same question, NWN provided a more definitive reply. In short, this is simply an example of the relevance of timely information and is not quite as dramatic as CUB suggests on page 37, lines 20-22, of their testimony.

Q. How do you address CUB's concerns regarding PGE's replacement of NMR meters with AMI meters?

A. As indicated in PGE's responses to Staff Data Request Nos. 507 and 508 (provided as Exhibit 2302), we will replace certain NMR meters as part of the AMI project because they are either: 1) not capable of storing necessary data, or 2) have higher recurring costs for transmission of the data back to PGE. Because the financial results for the proposed system are favorable, we believe this transition is justified.

Q. What is your response to CUB's concerns that PGE has not fully accounted for other utilities' analyses of AMI?

A. PGE has done so and will demonstrate below that there is more to these other utilities' analyses than CUB has indicated.

Q. How does the Pacific Gas and Electric's (PG&E's) case diverge from CUB's summary?

A. A preliminary review of PG&E's costs indicates that they included a $130 million contingency in their analysis. PGE has not included a contingency in its estimate. If PG&E's AMI cost is reduced by this contingency, their program comes much closer to economic viability purely on the operational benefits and is less dependent on demand-response benefits to appear viable.

Q. CUB points to Southern California Edison (SoCal Ed) as an example of a utility that concludes that AMI is not yet cost-effective. Does PGE believe this is a relevant conclusion?

A. Not in light of the fact that on Monday, August 21, 2006, SoCal Ed announced its plans to begin an advanced metering initiative in 2007, including the replacement of five million residential and small commercial meters between 2008 and 2012. This, however, is another example of the relevance of timely information. As reported in *Megawatt Daily* (August 22, 2006, page 9), California Public Utilities Commission President Micheal Peevey stated that, "Compared with fellow investor-owned utilities in California …, SoCal Ed has been slow to embrace advanced meters."

Q. How do PGE and San Diego Gas and Electric (SDG&E) diverge in their analysis of AMI?

A. SDG&E shares a state regulatory environment with PG&E and SoCal Ed. California's regulatory impetus for demand response obligated SDG&E to find some demand response benefit within its existing program. As noted above, PGE has not included demand response benefits in its current analysis but will pursue them with Commission approval and after discussion with Staff and other parties.

Q. Do you observe any shortcomings with CUB's citation from Jesse Berst's editorial opinion that meter prices will fall by 50%?

A. Yes, there are at least two shortcomings. First, the author provides no starting point and thus creates an incomplete timeline for any price change. Without a starting price, such price reductions may have already been "wrung out" of the market, particularly by the time PGE begins purchasing metering hardware. Second, citations should be made within the context of an entire article. Mr. Berst begins his editorial, "Don't get me wrong – I consider advanced metering essential to the Smart Grid" (CUB Exhibit 211, page 1). He later reiterates his support and summarizes his analysis for utilities to roll out systems: "Despite the confusion, I do not advocate waiting. Advanced metering is too important and too empowering" (CUB Exhibit 211, page 2). CUB "got him wrong" with the singular reference.

According to PGE's experience, prices for AMI systems have stabilized. PGE's direct involvement with AMI systems over the last 10 to 15 years has shown that: 1) prices for power line carrier systems remain flat, and 2) although radio-frequency-based systems have seen price reductions, we believe significant reductions are unlikely (see PGE's response to OPUC Data Request No. 429, provided as Exhibit 2303).

Q. Should PGE produce exhaustive investigations into potential load control programs prior to AMI investment?

A. No. PGE believes the current analysis demonstrates sufficient direct benefits. PGE's AMI platform will support any of the load control programs currently being proposed in the utility sector. As noted above, however, load control represents a secondary benefit to AMI and will require additional costs and investment. PGE agrees with Mr. Berst, Southern California Edison, and others, that the time for AMI investment is now.

Q. Does PGE believe that implementing an AMI system will lead to automatic and mandatory time-of-use pricing?

A. No. AMI's enabling technology will support a variety of secondary programs that will enhance the primary benefits included in our analysis. PGE will pursue time-of-use pricing if it meets our customers' needs and receives Commission approval, which we would seek after discussion with Staff and other parties.

Q. Would PGE be willing to file for AMI outside of a rate case proceeding?

A. Yes. PGE is willing to work with the OPUC Staff and other parties to separate AMI from this rate case.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
2301-C	**(Confidential – Provided under separate cover)** Projected AMI Capital Costs
2302	PGE's Responses to OPUC Data Request Nos. 507 and 508
2303	PGE's Response to OPUC Data Request No. 429

June 30, 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 June 19, 2006
Question No. 507

Request:

For each meter type identified in response to Staff Data Request No. 506 that already provides energy usage data to PGE by time of day, please explain why PGE proposes to replace the meter.

Response:

Excluding the meters listed in PGE's response to OPUC Data Request No. 508, there are approximately 35,000 non-residential solid state meters (all forms) that have time-of-use (TOU) capability but do not have the ability to store interval data. PGE proposes to replace these meters if we cannot retrofit them into AMI meters. The primary reasons are the high cost to manually read these meters and the high cost to program these meters if the time period in a TOU rate changes. In addition, these meters will not support critical peak pricing. We propose to replace the remaining non-residential meters listed in PGE's response to OPUC Data Request No. 506, because they have no TOU capability and replacing them will provide the estimated benefits described in PGE Exhibit 800.

June 30, 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 June 19, 2006
Question No. 508

Request:

Please state which nonresidential meters the company does *not* intend to replace through its AMI proposal in PGE/800, by customer size, meter type and number of meters.

Response:

PGE objects to this request on the basis of undue burden. Meter retention is based on the meter's functionality and not on the size of customer served. Further, PGE cannot provide customer size without considerable time and effort. Without waiving this objection, PGE provides the following types and quantities of meters:

Group 1: PGE has 15 meters (9S & 16S) with special functionality. These meters are located on customer sites on our distributed generation program and on customer sites where monitoring power quality is important. These meters have communication capability so that PGE can collect data on a daily basis, or as required.

Group 2: PGE has 100 meters (9S & 16S) with telephone modems and all are equipped to collect interval data. These meters have communication capability so we collect data on a daily basis or as required.

Group 3: PGE has 100 meters (9S & 16S) identical to Group 2 except that there is a recurring telephone charge (approximately $12 to $35 per month per meter) to read these meters, either for PGE or the customer. All these meters will be exchanged because the payback of a new AMI meter (installed cost is approximately $420) to avoid the recurring cost is 1 to 3 years. PGE will retain these meters until we determine if there is a location where these meters can be utilized without a recurring cost.

Group 4:
By year end 2006 (prior to when we would sign definitive AMI vendor agreements for our proposed AMI deployment), PGE will have approximately 3,000 non-residential meters (6S, 9S, & 16S) that are supported by most of the vendors we are considering for the AMI project. In other words, depending on the AMI vendor selected, PGE plans to install internal communication modules, which will allow the meters to provide AMI functionality. We began purchasing these meters in late 2005 as our standard commercial meter. All of these meters will be exchanged, then retrofitted and tested, before using them in our AMI meter inventory.

Group 5: PGE has 2,050 non-residential meters (6S, 9S & 16S) mostly installed in 2001 to support direct access and other market-based pricing options. In general, these meters are installed on PGE's largest customers. These meters each have a monthly recurring cost and the proposed AMI meters have a five-year payback to avoid these costs (i.e., the recurring communication cost per meter is $6.25 per month and the new AMI meter installed cost is approximately $420). In addition, most of these meters have a battery that PGE expects will fail within the next 3 years. The new AMI meters under consideration do not require a battery. Consequently, the actual payback is considerably less if the installed battery replacement cost of $175 is considered. PGE will retain these meters until we determine if they are more useful to serve isolated locations, based on their more powerful radios, than the proposed AMI meters.

Group 6:
PGE has approximately 1,000 (all non-2S forms) solid state meters that store interval data and have the capability to be programmed with time-of-use (TOU) rates. These meters are used for load research locations and also at some large customer locations. All of these meters will be exchanged in order to have a meter with communications capability. If these meters can be converted to AMI meters, we will do so, if cost effective. Otherwise PGE will retain these meters until we determine what locations might require manual interval data collection because no AMI network service is available.

Group 7:
PGE has approximately 2,500 solid state 2S meters (single phase, 240 volt service) that store interval data and have the capability to be programmed with TOU rates. Most of these are used to support customers on residential and small commercial TOU schedules. Some are being used for load research. For the same reason as Group 6, these meters will be exchanged, but PGE will retain them until we determine what locations might require manual interval data collection because no AMI network service is available.

June 8, 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 May 9, 2006
Question No. 429

Request:

Please describe the advanced metering infrastructure (AMI) technology and cost trends since PGE's last general rate case (UE 115), and the projected trends over the next five years, that lead the Company to believe that 2007-09 is the appropriate time to install an AMI system. Please provide copies of the information the Company relied upon in responding to this data request.

Response:

As noted in PGE Exhibit 800, pages 2 through 4, AMI is a mature technology. PGE would not be a pioneer in the field of AMI; we would be following the lead of a host of other utilities, both large and small, that have seen the value of AMI. In addition, a number of parties have signaled their interest in moving forward with future methods of grid management and demand response.

AMI Cost Trends

Power Line Carrier-based (PLC) AMI: The cost to implement PLC metering has not changed significantly in the last six years, and PGE does not expect a significant change in the future. The cost to interface communications safely on the power grid – at both the meter end-point and at the substation – adds a significant cost per point that cannot be reduced with advances in electronics. However, increased utility acceptance of the lower-cost, two-way radio technologies might cause small price decreases as competition puts pressure on the PLC vendors.

Radio-based AMI: The cost to implement two-way radio-based communications has decreased 10% to 20% as AMI vendors borrow heavily from the substantial engineering knowledge gained to manufacture mobile phones, WiFi, and Bluetooth devices, etc. However, with high fixed costs, long lead time for projects, and considerable risk for vendors in the AMI industry, PGE does not see the basis for significant price decreases over the next 5 years.

AMI Technology Trends

<u>Power Line Carrier-b</u>
<u>ased AMI:</u> Over the last six years, one of the three leading PLC vendors, DCSI, has improved bandwidth and features in the host software. DCSI now faces increased competition from a new two-way solution by Hunt Technologies and increased acceptance of Cannon Technologies' two-way PLC system. Compared to modern communication networks, the bandwidth of PLC systems is very poor and the introduction of new vendors seems unlikely. Broadband over Power Line (BPL) is considered separately below.

<u>Radio-based AMI:</u> PGE received a number of radio-based solutions offered in response to its recent RFP. This is largely due to the advances in radio communications cited above. However, to successfully commercialize an AMI system, a vendor faces significant barriers to entry and PGE will only consider proposals from well-established companies in good financial standing. Although acceptable radio systems are lower-cost and generally have more functionality than the PLC technologies, all the radio technologies have less proven time in the field.

<u>Emerging AMI Technologies:</u> There is considerable discussion about various alternatives using Internet-based metering and interoperable meters. The latter term means any meter that can be used with a wide variety of communication devices placed inside the meter. While this is technically possible, PGE does not believe that it will occur in a robust way within the next five years. Among the significant issues that must be resolved before this can happen include the following:

- The utility industry must develop a system of standard measurement criteria for communication interoperability.
- Internet-Protocol (IP) based standards make security breeches easier. Consequently, a robust security model must be developed to protect information at the meter end-point.
- A highly fragmented utility industry has only modest influence on products developed by AMI vendors. Therefore, once standards are developed, a means to motivate AMI vendors to adopt the standards must be achieved.
- A viable IP-based system requires nearly ubiquitous premise access to an "always-on" internet network. Rural and lower-income residential areas do meet this requirement.

<u>Other Potential Supporting Technologies:</u>

- Broadband over Power Line (BPL) is a communication option (not directly related to AMI functionality) that is a wide-area-network communication technology to support Internet Protocol. As such, it will compete directly with DSL and Cable broadband services. Currently, the cost to implement a BPL network solution support of AMI would add substantially higher investment and recurring costs. Ultimately, BPL is commercially unproven and without a single, large-scale implementation in the U.S., BPL represents an unwarranted risk to support AMI.

Appropriate Time to Install an AMI System
See PGE Exhibit 800, page 3, line 17 through page 4, line 2, and "AMI Cost Trends," above.

Basis of this Response
The information above is based entirely on PGE's general knowledge of AMI vendor technology as well as manufacturing trends observed in the market. Personnel within PGE have been monitoring and working with this industry since 1993. PGE has no specific documents to provide with this response.