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July 15, 2005

Via Electronic and US Mail

Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem OR 97308-2148

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Application for Annual Adjustment to Schedule 125 Under the Terms of the Resource Valuation Mechanism
Docket No. UE 172

Dear Filing Center:

Enclosed please find the following items for filing in the above-referenced proceeding on behalf of the Industrial Customers of Northwest Utilities:

- One original and six (6) copies of the Confidential Direct Testimony of Randall J. Falkenberg; and

- One original and two copies of the Redacted Direct Testimony of Randall J. Falkenberg.

Please return one file-stamped copy of the document in the self-addressed, stamped envelope provided.

Thank you for your assistance.

Sincerely,

/s/ Sheila R. Ho
Sheila R. Ho

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Direct Testimony of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities upon the parties on the service list, shown below, by causing the same to be mailed, postage-prepaid, through the U.S. Mail. Only parties who executed the protective order are being provided the confidential version of the testimony and exhibits.

Dated at Portland, Oregon, this 15th day of July, 2005.

/s/ Sheila R. Ho
Sheila R. Ho

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 172

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
	)
Application for Annual Adjustment to	)
Schedule 125 Under the Terms of the	)
Resource Valuation Mechanism.	)
	)

2006 RESOURCE VALUATION MECHANISM POWER COSTS

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

Redacted Version
(Confidential Information Removed and Shaded)

July 15, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Sandy Springs, Georgia 30350.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a utility rate and planning consultant holding the position of President and Principal with the firm of RFI Consulting, Inc. ("RFI"). I am appearing in this proceeding as a witness for the Industrial Customers of Northwest Utilities ("ICNU").

Q. PLEASE BRIEFLY DESCRIBE THE NATURE OF THE CONSULTING SERVICES PROVIDED BY RFI.

A. RFI provides consulting services in the electric utility industry. The firm provides expertise in electric restructuring, system planning, load forecasting, financial analysis, cost of service, revenue requirements, rate design, and fuel cost recovery issues.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. Exhibit ICNU/101 describes my education and experience within the utility industry. I have more than 25 years of experience in the industry. I have worked for utilities, both as an employee and as a consultant, and as a consultant to major corporations, state and federal governmental agencies, and public service commissions. I have been directly involved in a large number of rate cases and regulatory proceedings concerning the economics, rate treatment, and prudence of nuclear and non-nuclear generating plants.

During my employment with EBASCO Services in the late 1970s, I developed probabilistic production cost and reliability models used in studies for 20 utilities. I personally directed a number of marginal and avoided cost studies performed for compliance with the Public Utility Regulatory Policies Act of 1978 ("PURPA"). I also participated in a wide variety of consulting projects in the rate, planning, and forecasting areas.

In 1982, I accepted the position of Senior Consultant with Energy Management Associates ("EMA"). At EMA, I trained and consulted with planners and financial analysts at several utilities using the PROMOD III and PROSCREEN II planning models.

In 1984, I was a founder of J. Kennedy and Associates, Inc. ("Kennedy"). At that firm, I was responsible for consulting engagements in the areas of generation planning, reliability analysis, market price forecasting, stranded cost evaluation, and the rate treatment of new capacity additions. I presented expert testimony on these and other matters in more than 100 cases before the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions and courts in Arkansas, California, Connecticut, Florida, Georgia, Kentucky, Louisiana, Maryland, Michigan, Minnesota, New Mexico, New York, North Carolina, Ohio, Oregon, Pennsylvania, Texas, Utah, West Virginia, and Wyoming. Included in Exhibit ICNU/101 is a list of my appearances.

In January 2000, I founded RFI Consulting, Inc. with a comparable practice to the one I directed at Kennedy.

Q. HAVE YOU PREVIOUSLY APPEARED IN ANY PROCEEDINGS BEFORE THE OREGON PUBLIC UTILITY COMMISSION?

A. Yes. I filed testimony in five Portland General Electric ("PGE" or "the Company") cases: UE 137 and UE 139 in 2002, UE 149 in 2003, UE 161 in 2004, and UE 165/UM 1187 in 2005. In those cases, I addressed PGE's Resource Valuation Mechanism ("RVM"), and PGE's request for a Power Cost Adjustment Mechanism ("PCAM") and Hydro Generation Adjustment ("HGA"). I also filed testimony in several PacifiCorp proceedings in Oregon: UE 111, UE 116, UM 995, UE 134, UM 1050, and UE 170. In those cases, I addressed issues related to power cost modeling, PCAM, power cost deferrals, prudence of new resources, and multi-state jurisdictional allocation.

Q. HAVE YOU APPEARED AS AN EXPERT IN OTHER PROCEEDINGS INVOLVING FUEL OR POWER COST ISSUES?

A. Yes. I have been involved in a number of PacifiCorp proceedings in California, Utah, and Wyoming, where I testified concerning power cost issues. In Texas, I have also been involved in a number of power cost related cases. Finally, I have appeared in a number of other cases where fuel or purchased power costs were at issue. Exhibit ICNU/101 summarizes other cases in which I have appeared.

II. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. ICNU has asked me to examine PGE's proposed RVM update for 2006. I have identified certain problems in the PGE Monet study input assumptions that overstate the Company's projected power costs and, consequently, the rates computed under Schedule 125.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have concluded as follows:

1. PGE's June 10, 2005 variable power cost estimate of $646.6 million for 2006 is overstated. I recommend that PGE's power costs be reduced by $15.1 million. This results in total variable net power costs of $631.6 million based on PGE's preliminary Monet studies.

2. PGE includes the cost of four 2001 purchase contracts in its 2006 Monet study. These transactions were entered into between January and August 2001, more than 40 months prior to their delivery date. In UE 139, the Commission found that similar contracts negotiated in 2001 for 2003 delivery were imprudent, because the market was not liquid when the transactions were negotiated. I recommend these additional contracts be re-priced in Monet, reducing net power costs by $7.2 million.

3. PGE includes capacity tolling contracts that are above market and/or produce no benefits in Monet. Inclusion of these contracts in Monet would amount to an attempt to require ratepayers to provide earnings insurance for shareholders with no possibility of benefit. I recommend their removal, reducing net power costs by $2.9 million.

4. PGE has continued to modify its modeling of hydro resources in violation of the Stipulation in RVM 2004 (UE 149). As a result, I recommend rejection of the Company's proposed changes to hydro capacity modeling, resulting in a decrease in net power costs of $2.6 million. If the Commission is inclined to allow the proposed hydro capacity changes, there are other hydro modeling issues that should be addressed as well. It appears that the Company incorrectly models potential spinning reserve contributions of gas units, potentially understating hydro capacity available for serving load. If the Commission desires to allow the Company to change the hydro capacity modeling, that change should occur in PGE's next rate case when the Company and parties have the opportunity to fully address all aspects of this issue.

5. The Company has included an outage of the Sullivan hydro plant. This same outage was included in UE 161, but it was postponed. Because the currently planned outage is longer than the original, part of this cost amounts to a "double count." The Commission should remove a portion of the cost of this outage from the Monet study. This would reduce net power costs by $2.4 million.

III. RVM NET VARIABLE POWER COST ISSUES

Q. WHAT ARE "NET VARIABLE POWER COSTS" AND WHY ARE THEY IMPORTANT TO THIS PROCEEDING?

A. Net variable power costs are the variable production costs related to fuel and purchased power expenses, net of power sales revenue. In the context of this case, net variable power costs are estimated using PGE's Monet production cost model. Based on the Stipulation Concerning Power Costs in PGE's last general rate case, UE 115, updates to net variable power costs are reflected in changes to the rates under Schedule 125 parts A and B. According to the tariff:

> The Part A and Part B revisions shall reflect updates to the following:
>
> - Applicable resources
> - Company market power purchases
> - Cost of fuel and transportation
> - Hydro operating constraints imposed by governmental agencies
> - Market power prices (including transmission to the Company)
> - Transmission and ancillary services
> - Retail load forecast

Schedule 125, Sheet No. 125-4 (Dec. 8, 2003).

Q. WHAT INFORMATION, DOCUMENTS, AND DATA DID YOU REVIEW IN ORDER TO ANALYZE PGE'S POWER COSTS?

A. I read PGE's direct testimony and discovery responses and examined the modeling assumptions used in PGE's Monet power cost model in order to make recommendations regarding the proper level of net variable power costs for 2006. In addition, I have reviewed PGE's draft Monet run filed on June 10, 2005.

Q. HAS PGE PRESENTED ITS FINAL MONET RUN IN THIS CASE?

A. Not yet. The Company plans to continue to perform Monet updates as additional information becomes available. The changes I recommend to Monet should be made by the time of the Company's final Monet run. However, I have estimated the impact of my proposed adjustments based on the most current version of Monet and PGE's discovery responses.

2001 Purchase Contracts

Q. WHY DO YOU PROPOSE AN ADJUSTMENT TO REPRICE FOUR 2001 PURCHASE CONTRACTS?

A. The Company has included [redacted] million in the 2006 Monet run for purchased power contracts with Morgan Stanley Capital Group, Inc., El Paso Merchant Energy, L.P., and Mirant Americas Energy Marketing, L.P. These contracts supply 100 MW of around the clock (flat) power. These purchases have an average price of more than [redacted]. This power was contracted for between January 29 and August 16, 2001, when market prices and forward prices were quite high. These high costs are a residual effect of the wholesale market problems that occurred from mid-2000 to June 2001.

Q. SHOULD THESE CONTRACTS BE INCLUDED IN THE 2006 RVM?

A. No. In UE 139, the Commission made a substantial disallowance related to 2003 power contracts made in the first half of 2001. These 2006 contracts were entered into at the same time, and the Commission should make a disallowance for these contracts for the same reasons as it made for the 2003 contracts.

Q. PLEASE DESCRIBE THE CIRCUMSTANCES RELATED TO THE POWER CONTRACT DISALLOWANCE IN UE 139.

A. In UE 139, PGE included costs for four on-peak purchases for 125 MW of power with above-market prices. Those contracts were all negotiated in early 2001, for delivery in 2003. Staff, ICNU, and CUB all recommended disallowances related to these contracts. The Commission adopted a total disallowance of $14.7 million related to these contracts on the basis that the Company entered into these transactions before the market was liquid, and because making such purchases violated PGE's general practice of purchasing 12 to 18 months forward. As a result, the Commission made a disallowance for the forward contracts with delivery dates after February 2003:

> Here, it is undisputed that PGE's decision to purchase 2003 power in early 2001 was unusual. Despite the parties' arguments about the nature of PGE's power procurement policies, PGE acknowledges that, since the mid-1990s the company's general practice has been to purchase power 12 to 18 months ahead of the calendar year. In this case, PGE entered the four disputed contracts outside that window, making two purchases some 23 months in advance, with the two others occurring 22 and 19 months prior to delivery.
>
> In addition, we find that PGE made the purchases before the market was liquid. As PGE explains, market liquidity is a function of the number of like transactions conducted during a relevant time period. PGE defines "like transaction" as a transaction within the region, available to PGE for forward delivery during a similar time frame. For our purposes here, we interpret that definition to exclude all trades made outside the Pacific Northwest region for periods other than 2003.
>
> * * *
>
> While it is a close call, we conclude that, based on the totality of the circumstances that existed in early 2001, PGE acted prudently in purchasing advanced power for the winter months of 2003. The NPPC's concerns about the availability of wholesale power during that period, combined with the overall market volatility and news that California might begin purchasing large amounts of long-term power, reasonably prompted PGE to buy power to help ensure adequate reliability for its customers during the winter of 2003.
>
> We further conclude, however, that PGE has failed to establish the reasonableness of its decision to purchase high-priced power for the remainder to the 2003 calendar year. As stated above, concerns about supply availability in 2003 were confined to the winter months, not the entire calendar year. Moreover, prior to

> signing the contracts, PGE knew or should have known that the power market situation was improving due to increased development of generation facilities.
>
> * * *
>
> Accordingly, we agree, in part, with Staff's recommendation to disallow the disputed contracts. Based on the concerns about availability of wholesale power during the winter months of 2003, we will not disturb PGE's decision to secure a portion of its purchased power needs for the months of January and February 2003. The remaining 10 months of those contracts, however, should be repriced to more appropriate levels.

Re PGE, OPUC Docket No. UE 139, Order No. 02-772 at 11-14 (Oct. 30, 2002) (internal footnotes omitted) ("Order No. 02-772").

Q. HOW DO THE CONTRACTS IN QUESTION IN THIS CASE COMPARE TO THOSE DISCUSSED ABOVE?

A. In this case, the argument for imprudence is even more compelling. First, these new contracts were all negotiated during the same timeframe and with the same counterparties (Mirant Americas, Morgan Stanley, and El Paso) as those disallowed by the Commission in UE 139. Indeed, the highest price contract, Mirant, was negotiated on January 29, 2001, the same day as one of the contracts disallowed in UE 139. Second, these contracts all began delivery in 2004, or ten months *later* than the contracts the Commission considered imprudent in UE 139, and deliveries continue through 2006. The 2005 deliveries are 22 months later than the contracts already considered imprudent by the Commission in UE 139. Third, the products purchased are not on-peak power, but rather flat or "around the clock" power products. This means that a relatively low-value product (off-peak power) was coupled with the more valuable on-peak product. Given the Commission's finding that even purchases of on-peak power delivered after

February 2003 were imprudent, it is hard to see any justification for PGE to purchase a flat power product to be delivered at a much later time. While the Commission stated in the above-referenced passage that imprudence was a "close call" for the UE 139 contracts, it is much less so in the case of these four contracts.

Q. HOW SHOULD THE COMMISSION DEAL WITH THIS ISSUE?

A. The development of an imprudence adjustment is always a difficult undertaking. The Commission accepted Staff's alternative methodology for addressing this problem in UE 139. In that case, the Commission priced the imprudent 2003 contracts based on PGE's forward price curve in use approximately 18 months prior to delivery because that was when the market became liquid.[1/]

In UE 149, the same issue concerning these four contracts arose. In that case, Staff witness Maury Galbraith testified that the Staff's alternative methodology from UE 139 (18-month ahead forward curve) was no longer valid. Re PGE, OPUC Docket No. UE 149, Staff/100, Galbraith/23 (July 2, 2003). Attached as Exhibit ICNU/102 is an excerpt of Mr. Galbraith's direct testimony in UE 149, in which he discussed these issues. Mr. Galbraith testified that market liquidity had declined since the time of UE 139, and therefore, the 18-month ahead forward curve could not be considered a good representation of market liquidity. ICNU/102, Falkenberg/9. He further testified that it was not appropriate to reprice three-year contracts as though they were three one-year

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1/ At page 14 of Order No. 02-772, the Commission found that "[t]he proxy price should be based on what PGE would have paid if it prudently waited for the market to become liquid."

deals. Id. Had Mr. Galbraith supported the UE 139 methodology, the disallowance would have been $11.1 million. Id. at Falkenberg/8. Instead, Mr. Galbraith recommended use of a proxy price based on the lowest cost of the 4 contracts. Id. at Falkenberg/10. Based on this approach, he recommended a disallowance of $7.2 million. Id. Ultimately, the case was settled with much give and take among the parties, and the settlement in that case provides no precedent for this one.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION IN THIS CASE?

A. The Staff methodology from UE 149 is a reasonable approach, and I recommend it be applied in this case. Confidential Exhibit ICNU/103 shows that this approach produces a disallowance of $7.2 million.

Q. IF THE COMPANY WERE TO HAVE LIQUIDATED ITS POSITION RELATIVE TO THESE CONTRACTS, WOULD THAT CHANGE YOUR RECOMMENDATION?

A. No. The Company (as yet at least) has not "sold" these contracts. They are still listed in the Monet inputs and outputs. In addition, even if the Company subsequently sold firm energy in the same amount of the 2001 contracts, that transaction would be completely independent of the original contracts, regardless of "why" the Company may have entered into such a trade. The prudence of such transactions (if any) would have to be judged against the market conditions at the time that the sale occurred. One cannot turn an imprudent decision into a prudent one after the fact.

<u>Capacity Tolling Contracts</u>

Q. WHAT IS A CAPACITY TOLLING CONTRACT?

A. These are contracts that function like a spark spread option contract. They allow PGE the right to obtain additional energy when the market price for energy exceeds the price of gas-fired energy with a specific heat rate.

Q. CAN YOU PROVIDE AN EXAMPLE THAT ILLUSTRATES HOW SUCH CONTRACTS OPERATE?

A. Yes. In this example, I am using only hypothetical numbers. In such a contract, pricing for energy is based on a gas index, heat rate, exercise price, and demand charge. Assume, for example, a heat rate of 10.0 MBTU/kWh and an exercise price of $1/MWh, the gas price index at $5.00, and a monthly demand charge of $1.00/kW.

In this example, the demand charge is irrelevant to the decision to obtain the energy allowed under the contract. The "strike price" in this example would be as follows:

(Gas Price Index) times (Heat Rate) plus Exercise Price; or

5.00*10+1 = $51/MWh.

Consequently, if power prices exceed $51/MWh, it makes sense to exercise the option because it would provide energy cheaper than the market. However, this does not mean than every time market prices exceed $51/MWh, the contract would be "in the money." If gas prices where higher than $5.00, the market price would have to exceed $51/MWh for the contract to be "in the money."

Q. DOES PGE INCLUDE ANY CAPACITY TOLLING CONTRACTS IN MONET?

A. Yes, PGE has two capacity tolling agreements included in its Monet study. The demand charges ($2.9 million in 2006) of these contracts are reflected in Monet; however, the contracts are never "in the money" based on PGE's 2006 gas and power price assumptions. Thus, these contracts never dispatch in the model. As a result, these contracts add a "dead weight" cost to the model, with no offsetting benefits for ratepayers.

Q. IS THIS A REASONABLE TREATMENT FOR SUCH COSTS?

A. No. This approach simply saddles ratepayers with additional costs, and allows shareholders to receive any benefits that might result if the contracts in question actually are dispatched at some time during 2006.

Q. WHEN DID PGE FIRST INCLUDE THESE CONTRACTS IN MONET?

A. They were first included in the November 2004 update for RVM 2005. In that case, Staff opposed their inclusion in Monet, and filed a request for a pre-hearing conference. Exhibit ICNU/104 is a copy of the letter from Staff regarding this issue, along with PGE's response and the Administrative Law Judge's memorandum regarding the matter.

Q. IS ICNU SATISFIED WITH THE OUTCOME OF THIS ISSUE SINCE THE ORDER WAS ISSUED IN UE 161?

A. No. While the parties in UE 161 agreed to work informally to arrive at a solution in PGE's next rate case, no real progress has been made. While Staff has not done so yet, it reserved the right to seek a deferral of the costs of the capacity tolling agreements for 2005. It appears that PGE has now taken the position that the capacity tolling agreement issue will be addressed by the Stipulation in UE 165/UM 1187, based on the Company's agreement to hire a consultant to study ways to incorporate stochastic modeling into Monet. OPUC Docket No. UE 172, PGE Response to ICNU Data Request ("DR") No. 1.34(b) (May 11, 2005).

Q. DO YOU AGREE THAT THE STIPULATION IN UE 165/UM 1187 ADDRESSES THIS PROBLEM ADEQUATELY?

A. No. The Stipulation merely requires PGE to fund a consultant study of ways to improve Monet. There is no specific mention of the capacity tolling contract issue in the Stipulation. Further, the Stipulation does not even require PGE to implement any changes to Monet that the consultants might suggest.

Q. IF THE COMMISSION ADOPTS THE STIPULATION IN UE 165/UM 1187 AND ESTABLISHES THE SYSTEM DISPATCH POWER COST ADJUSTMENT MECHANISM ("SD-PCAM"), DOES THAT ENSURE BENEFITS FROM THE CAPACITY TOLLING AGREEMENTS WILL FLOW TO RATEPAYERS?

A. No. Under the SD-PCAM, PGE would re-run Monet using actual gas and power prices. It is possible that under some combinations of fuel and power prices, Monet would show these contracts being dispatched. However, the Company has already acknowledged that [redacted] OPUC Docket No. UE 172, PGE Response to ICNU DR No. 1.27 (May 27, 2005). As a result, it is questionable whether the modeling in the Monet backcast study will provide a reasonable modeling of the contracts. Further, the Company has not yet been able to demonstrate the logic changes it plans to make to Monet for application of the SD-PCAM. Finally, under all market price forecasts and gas price assumptions used by the Company for the past seven months, these contracts have never been "in the money." Even if the model does show some dispatch of these resources, it is quite possible that they would not be sufficient to offset the costs the Company seeks to recover from ratepayers.

Q. PGE CONTENDS THAT THESE CONTRACTS ARE PRUDENT. DO YOU AGREE?

A. The Company has never demonstrated the prudence of these contracts, nor has it provided any cost-benefit analysis of them. However, the basic problem with these contracts is that there is a fundamental mismatch between the kinds of benefits the contracts produce, as compared to the tools that are used in ratemaking.

Q. PLEASE EXPLAIN.

A. The benefit of these contracts stems from their ability to put a cap on power costs in the event of extreme changes in the relationship between gas and power prices. When power prices are high relative to gas prices, these contracts are "in the money." For this to happen, it would typically mean that capacity shortages are occurring in the wholesale market driving up the spark spread between wholesale gas and power prices.

However, Monet only reflects a single point estimate of power and gas prices. While both quantities are uncertain variables, the Monet model treats them as point estimates. Consequently, the ability to offset power price spikes is of no value in Monet. As pointed out above, this issue may be studied if the Commission approves the Stipulation in UE 165/UM 1187. However, even if a solution is found (and there is no guarantee of that), PGE is not obligated to implement it, and it most certainly will not be available in 2006. Thus, there appears to be no way in which ratepayers can benefit from these additional costs if they are included in RVM 2006. It merely amounts to a "one-way street" where investors retain the benefits, while ratepayers absorb the costs.

Q. WHAT IS YOUR PROPOSAL FOR DEALING WITH THIS ISSUE?

A. I recommend that the Commission require the removal of these contracts from RVM 2006. This will remove the excess costs from the study. If the Commission adopts the Stipulation in UE 165/UM 1187, it will allow the Company to retain any benefits from the contracts that might actually materialize in 2006, because the contracts would not be reflected in the Monet backcast studies used in the SD-PCAM.

Q. HAVE SITUATIONS LIKE THIS ARISEN BEFORE?

A. Yes. In UE 147 and UE 170, PacifiCorp initially requested recovery of fixed costs associated with a hydro hedge contract. This contract was opposed by parties on the basis that the costs were included in the test year, but no benefits could be reflected in PacifiCorp's power cost model (GRID). In both cases, settlements were reached, so there is no clear precedent. However, in both cases, the Company proposed to implement a balancing account to pass through other payments and receipts from the hydro hedge. As the Company later withdrew those requests, it is reasonable to infer that it also dropped the request for recovery of the hydro hedge. The Commission adopted the stipulation in UE 147. Approval of the UE 170 Partial Stipulation, which addresses this issue, is pending the final hearing in the case.

Monet Updates and Enhancements

Q. SUMMARIZE THE REQUIREMENTS OF THE STIPULATION IN UE 149 AS CONCERNS MONET UPDATES AND ENHANCEMENTS.

A. In UE 149, PGE proposed a substantial number of changes to the Monet model logic. ICNU and other parties had objections to PGE's changes. In particular, ICNU argued that the Company had made selective changes in the model, focusing on changes that increased costs, while ignoring those that reduced costs. Re PGE, OPUC Docket No. UE 149, ICNU/100, RJF/14 (July 2, 2003). ICNU further argued that the language of Schedule 125 did not permit the substantial changes proposed by PGE. Id. at RJF/12-13. Finally, ICNU suggested in the alternative that if PGE's proposal to improve Monet were allowed, then the hydro dispatch logic should be improved to better match market prices. Id. at RJF/21, 31. ICNU also proposed modifying PGE's proposed change to the Beaver plant dispatch logic.

To resolve this issue, it was agreed among the parties that PGE would be allowed to make limited changes to Monet related to hydro modeling and the Beaver and Coyote dispatch. The Stipulation required PGE to conduct workshops related to the development of new logic and work with the parties to develop mutually agreeable logic changes. In the event the parties agreed to the new logic, there was a broad prohibition against additional logic changes outside of a new general rate case.

Q. DID PGE MAKE THE LOGIC CHANGES TO MONET REQUIRED BY THE STIPULATION?

A. PGE was required to make a good faith effort to complete the logic change by December 31, 2003. PGE may have missed this deadline, but the new logic was included in the April 2004 (UE 161) filing. I believe the Company and all parties made a good faith effort. Unfortunately, the Company did not agree to freeze the Monet model development in UE 161. While I would have been satisfied to freeze the model at that point in time, the Company has continued to make changes to the hydro modeling. The most significant change in this case is a change to the hydro capacity modeling used in the new optimization logic.

Q. EXPLAIN THIS NEW CHANGE TO MONET.

A. PGE changed the hydro shaping logic in UE 161. It has now decided that to properly implement this change, it also needs to change the definition of hydro capacity used by the model. The Company changed the hydro capacity from the maximum or "nameplate" capacity of the hydro resources to the average amount of "usable capacity" available as provided to PGE by Central.[2/] OPUC Docket No. UE 172, PGE Response to ICNU DR No. 1.2 (May 2, 2005). PGE now contends that use of this average capacity is more appropriate than the maximum capacity because it reflects outages, derations, maintenance, encroachment, and other factors. Id.

[2/] Central is the entity that manages the Mid-Columbia projects.

Q. IS THERE ANY REASON WHY THIS CHANGE COULD NOT HAVE BEEN INCORPORATED INTO THE MONET MODEL IN UE 161?

A. No. The Company seems to have been aware of this issue for some time, as it was discussed during the workshops. The only reason why the Company did not incorporate it into UE 161 (per the requirements of the Stipulation in UE 149) was that it did not apply sufficient resources to the problem at the time. It was not because parties such as Staff, CUB, or ICNU delayed the process.

Q. DOES THE STIPULATION ALLOW PGE TO MAKE ADDITIONAL CHANGES TO THE HYDRO MODELING IN THIS CASE?

A. No. PGE and the parties were required to make a good-faith effort to complete the model changes by December 31, 2003. Re PGE, OPUC Docket No. UE 149 Stipulation at 3 (Aug. 19, 2003) ("UE 149 Stipulation"). PGE actually missed this deadline by a few months, but I believe the Company and all parties made a good-faith effort. As there was no criticism of PGE's modified hydro logic by ICNU, CUB, or Staff in RVM 2005 (UE 161), the requirements of the UE 149 Stipulation were met, and no additional changes should be allowed. Therefore, the Commission should not entertain any more changes to the model in this case.

Q. DOES PGE'S PROPOSED CAPACITY MODELING AMOUNT TO AN "ENHANCEMENT" TO MONET AS DEFINED IN THE UE 149 STIPULATION?

A. Yes. PGE is changing the manner in which capacity is defined in the model. These change are not due to any physical changes in the hydro resources themselves, but rather because PGE does not (now) agree with the way in which its new hydro logic applies this input capacity. To address this, PGE proposes "*changes to the method used to compute the input data to Monet*," which are prohibited by the UE 149 Stipulation. UE 149 Stipulation at 4. This was specifically forbidden in the Paragraph 6 of the UE 149 Stipulation. This would have to be considered an "enhancement" to the model, and again, a one-sided one. The Company has focused on changes to the model that increase power costs, while ignoring other important and highly related factors that would reduce power costs.

Q. PLEASE EXPLAIN.

A. A major problem is that the new hydro dispatch logic also makes deductions for operating reserves and regulating margins exclusively from the hydro capacity on the system. Thus, the Company has substantially reduced (relative to actual experience) the amount of capacity that is actually used to serve loads. This can be seen by comparing the distribution of hourly hydro generation for January 2004 (actual) to the January 2006 hourly distribution in Monet as shown in Exhibit ICNU/105. The exhibit also shows the monthly minimum, maximum, and standard deviation of hourly hydro generation for each month comparing actual 2004 results to the results in the Monet run for 2006.

The exhibit shows that Monet has a much lower maximum capacity and much higher minimum capacity than has occurred in actual practice. It also shows that the distribution of hydro capacity has a much larger standard deviation in actual practice than the Monet modeling suggests. This means that the actual operation of hydro resources is much more dynamic than assumed by the Company, giving operators much greater flexibility. By reducing the maximum capacity, while increasing the minimum capacity, Monet is dampening the ability of the hydro resources to maximize the value of hydro generation as compared to market prices, which increases net power costs.

Q. DOES EXHIBIT ICNU/105 ACCOUNT FOR THE RECENT REDUCTION IN CAPACITY DUE TO THE MID-COLUMBIA CONTRACT RENEGOTIATIONS?

A. No. However, the reduction is only about 75 MW, which is substantially less than the difference between the monthly maximum capacities and the figures used in Monet. Because there is no actual data available that reflects these changes, it is not possible to reflect this change in the exhibit.

Q. ARE THERE REASONS WHY THE PROPOSED MONET MODELING IS INCORRECT?

A. Yes. The Monet logic assumes that reserves and regulating margins are only carried on hydro units. However, there are times when it would be more economical to carry these reserves on gas units, based on the Monet input assumptions.

Q. WHAT WOULD HAPPEN IF RESERVES WERE CARRIED ON GAS UNITS?

A. In on-peak hours, the amount of hydro capacity available would increase, and the cost of fuel would decrease because hydro would be offsetting the gas used in Coyote or Beaver. In off-peak hours, the cost of purchased power would increase because there would be less hydro energy available due to the increased use of that energy in on-peak hours. If the cost of the additional off-peak power is less than the cost of on-peak gas generation, then overall the system will save money.

Q. CAN YOU DEMONSTRATE THAT THIS IS A LOGICAL MODE OF OPERATION?

A. Yes. Exhibit ICNU/106 shows that in a month when Beaver is being dispatched, savings can result from shifting reserve carrying requirements from the hydro units to Beaver. Further, review of actual generator logs for the gas units indicates they are not being fully loaded in actual operation. Exhibit ICNU/107 shows a capacity duration curve for the Beaver gas plant for August 2004 compared to Monet for August 2006. The chart shows that in Monet, Beaver is normally dispatched at full capacity, while in actual practice it is seldom operated at its maximum capacity. When the units are not fully loaded, additional capacity is available for carrying reserves and does not need to come from the hydro units. The same is true in months when only Coyote is being dispatched. However, it is not possible at this time to optimize this mode of operation outside of the model. This would require additional changes to Monet. Thus, it is not possible to fully quantify this effect. Based on one month of data, however, the impact could be substantial, as shown in Exhibit ICNU/106.

Q. WHAT THEN IS YOUR RECOMMENDATION TO THE COMMISSION?

A. I recommend that the Commission reject the Company's proposal to change the definition of hydro capacity in Monet, reversing Step 38, and reducing power costs by $2.6 million. This will leave the model where it stood in UE 161 without any additional "enhancements," which is consistent with the UE 149 Stipulation. If the Commission believes this "enhancement" should be allowed, it would be permissible to make this change in PGE's next rate case, which is expected to occur later this year. The Company could implement the proper logic in the model to reflect both the changes to the capacity definition and the adjustment to the hydro reserve logic at that time.

Sullivan Plant Outage

Q. DO YOU AGREE WITH PGE'S PROPOSAL TO INCLUDE THE 142-DAY SULLIVAN HYDRO PLANT OUTAGE IN THE MONET STUDY?

A. No. The Company had originally planned to perform this work in 2005, but it was postponed. The original 123-day outage was included in Monet in UE 161. The current outage is planned for 142 days. Unless the Commission removes 123 days of the currently planned outage from Monet, customers will be charged for the same outage twice. I recommend the Commission remove 123 days of this outage from Monet to prevent this double count. I estimate this adjustment would reduce power costs by $2.4 million. Exhibit ICNU/108 is a copy PGE's response to Staff Data Request No. 4, discussing this issue.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

EDUCATIONAL BACKGROUND

I received my Bachelor of Science degree with Honors in Physics and a minor in mathematics from Indiana University. I received a Master of Science degree in Physics from the University of Minnesota. My thesis research was in nuclear theory. At Minnesota I also did graduate work in engineering economics and econometrics. I have completed advanced study in power system reliability analysis.

PROFESSIONAL EXPERIENCE

After graduating from the University of Minnesota in 1977, I was employed by Minnesota Power as a Rate Engineer. I designed and coordinated the Company's first load research program. I also performed load studies used in cost-of-service studies and assisted in rate design activities.

In 1978, I accepted the position of Research Analyst in the Marketing and Rates department of Puget Sound Power and Light Company. In that position, I prepared the two-year sales and revenue forecasts used in the Company's budgeting activities and developed methods to perform both near- and long-term load forecasting studies.

In 1979, I accepted the position of Consultant in the Utility Rate Department of Ebasco Service Inc. In 1980, I was promoted to Senior Consultant in the Energy Management Services Department. At Ebasco I performed and assisted in numerous studies in the areas of cost of service, load research, and utility planning. In particular, I was involved in studies concerning analysis of excess capacity, evaluation of the planning activities of a major utility on behalf of its public service commission, development of a methodology for computing avoided costs and cogeneration rates, long-term electricity price forecasts, and cost allocation studies.

At Ebasco, I specialized in the development of computer models used to simulate utility production costs, system reliability, and load patterns. I was the principal author of production costing software used by eighteen utility clients and public service commissions for evaluation of marginal costs, avoided costs and production costing analysis. I assisted over a dozen utilities in the performance of marginal and avoided cost studies related to the PURPA of 1978. In this capacity, I worked with utility planners and rate specialists in quantifying the rate and cost impact of generation expansion alternatives. This activity included estimating carrying costs, O&M expenses, and capital cost estimates for future generation.

In 1982 I accepted the position of Senior Consultant with Energy Management Associates, Inc. and was promoted to Lead Consultant in June 1983. At EMA I trained and consulted with planners and financial analysts at several

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

utilities in applications of the PROMOD and PROSCREEN planning models. I assisted planners in applications of these models to the preparation of studies evaluating the revenue requirements and financial impact of generation expansion alternatives, alternate load growth patterns and alternate regulatory treatments of new baseload generation. I also assisted in EMA's educational seminars where utility personnel were trained in aspects of production cost modeling and other modern techniques of generation planning.

I became a Principal in Kennedy and Associates in 1984. Since then I have performed numerous economic studies and analyses of the expansion plans of several utilities. I have testified on several occasions regarding plant cancellation, power system reliability, phase-in of new generating plants, and the proper rate treatment of new generating capacity. In addition, I have been involved in many projects over the past several years concerning the modeling of market prices in various regional power markets.

In January 2000, I founded RFI Consulting, Inc. whose practice is comparable to that of my former firm, J. Kennedy and Associates, Inc.

The testimony that I present is based on widely accepted industry standard techniques and methodologies, and unless otherwise noted relies upon information obtained in discovery or other publicly available information sources of the type frequently cited and relied upon by electric utility industry experts. All of the analyses that I perform are consistent with my education, training and experience in the utility industry. Should the source of any information presented in my testimony be unclear to the reader, it will be provided it upon request by calling me at 770-379-0505.

PAPERS AND PRESENTATIONS

Mid-America Regulatory Commissioners Conference - June 1984: "Nuclear Plant Rate Shock - Is Phase-In the Answer"

Electric Consumers Resource Council - Annual Seminar, September 1986: "Rate Shock, Excess Capacity and Phase-in"

The Metallurgical Society - Annual Convention, February 1987: "The Impact of Electric Pricing Trends on the Aluminum Industry"

Public Utilities Fortnightly - "Future Electricity Supply Adequacy: The Sky Is Not Falling" What Others Think, January 5, 1989 Issue

Public Utilities Fortnightly - "PoolCo and Market Dominance", December 1995 Issue

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

APPEARANCES

3/84	8924	KY	Airco Carbide	Louisville Gas & Electric	CWIP in rate base.
5/84	830470-EI	FL	Florida Industrial Power Users Group	Fla. Power Corp.	Phase-in of coal unit, fuel savings basis, cost allocation.
10/84	89-07-R	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power	Excess capacity.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Phase-in of nuclear unit.
2/85	I-840381	PA	Phila. Area Ind. Energy Users' Group	Philadelphia Electric Co.	Economics of cancellation of nuclear generating units.
3/85	Case No. 9243	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Economics of cancelling fossil generating units.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped storage generating units, optimal res. margin, excess capacity.
3/85	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear unit cancellation, load and energy forecasting, generation economics.
5/85	84-768-E-42T	WV	West Virginia Multiple Intervenors	Monongahela Power Co.	Economics - pumped storage generating units, reserve margin, excess capacity.
7/85	E-7, SUB 391	NC	Carolina Industrial Group for Fair Utility Rates	Duke Power Co.	Nuclear economics, fuel cost projections.
7/85	9299	KY	Kentucky Industrial Utility Consumers	Union Light, Heat & Power Co.	Interruptible rate design.
8/85	84-249-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Prudence review.
1/86	85-09-12	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power Co.	Excess capacity, financial impact of phase-in nuclear plant.
1/86	R-850152	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Phase-in and economics of nuclear plant.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power	Optimal reserve margins, prudence, off-system sales guarantee plan.
5/86	86-081-E-GI	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Generation planning study , economics prudence of a pumped storage hydroelectric unit.
5/86	3554-U	GA	Attorney General &	Georgia Power Co.	Cancellation of nuclear

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Georgia Public Service Commission Staff		plant.
9/86	29327/28	NY	Occidental Chemical Corp.	Niagara Mohawk Power Co.	Avoided cost, production cost models.
9/86	E7- Sub 408	NC	NC Industrial Energy Committee	Duke Power Co.	Incentive fuel adjustment clause.
12/86 613	9437/	KY	Attorney General of Kentucky	Big Rivers Elect. Corp.	Power system reliability analysis, rate treatment of excess capacity.
5/87	86-524- E-SC	WV	West Virginia Energy Users' Group	Monongahela Power	Economics and rate treatment of Bath County pumped storage County Pumped Storage Plant.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
6/87	PUC-87-013-RD E002/E-015 -PA-86-722	MN	Eveleth Mines & USX Corp.	Minnesota Power/ Northern States	Sale of generating unit and reliability Power requirements.
7/87	Docket 9885	KY	Attorney General of Kentucky	Big Rivers Elec. Corp.	Financial workout plan for Big Rivers.
8/87	3673-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear plant prudence audit, Vogtle buyback expenses.
10/87	R-850220	PA	WPP Industrial Intervenors	West Penn Power	Need for power and economics, County Pumped Storage Plant
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Cost allocation methods and interruptible rate design.
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Nuclear plant performance.
1/88	Case No. 9934	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Review of the current status of Trimble County Unit 1.
3/88	870189-EI	FL	Occidental Chemical Corp.	Fla. Power Corp.	Methodology for evaluating interruptible load.
5/88	Case No. 10217	KY	National Southwire Aluminum Co., ALCAN Alum Co.	Big Rivers Elec. Corp.	Debt restructuring agreement.
7/88	Case No. 325224	LA Div. I 19th Judicial District	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization gas sales and revenues.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/88 gas	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of sales and revenues.
12/88	88-171-EL-AIR 88-170-EL-AIR	OH OH	Ohio Industrial Energy Consumers	Toledo Edison Co., Cleveland Electric Illuminating Co.	Power system reliability reserve margin.
1/89	I-880052	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Nuclear plant outage, replacement fuel cost recovery.
2/89	10300	KY	Green River Steel K	Kentucky Util.	Contract termination clause and interruptible rates.
3/89	P-870216 283/284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power	Reserve margin, avoided costs.
5/89	3741-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Prudence of fuel procurement.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Need and economics coal & nuclear capacity, power system planning.
10/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Power system planning, economic and reliability analysis, nuclear planning, prudence.
10/89	89-128-U	AR	Arkansas Electric Energy Consumers	Arkansas Power Light Co.	Economic impact of asset transfer and stipulation and settlement agreement.
11/89	R-891364	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Sale/leaseback nuclear plant, excess capacity, phase-in delay imprudence.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Sale/leaseback nuclear power plant.
4/90	89-1001-EL-AIR	OH	Industrial Energy Consumers	Ohio Edison Co.	Power supply reliability, excess capacity adjustment.
4/90	N/A	N.O.	New Orleans Business Counsel	New Orleans Public Service Co.	Municipalization of investor-owned utility, generation planning & reliability
7/90	3723-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization adjustment rider.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirements gas & electric, CWIP in rate base.
9/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Power system planning study.
12/90	U-9346	MI	Association of	Consumers Power	DSM Policy Issues.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Businesses Advocating Tariff Equity (ABATE)		
5/91	3979-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	DSM, load forecasting and IRP.
7/91	9945	TX	Office of Public Utility Counsel	El Paso Electric Co.	Power system planning, quantification of damages of imprudence, environmental cost of electricity
8/91	4007-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Integrated resource planning, regulatory risk assessment.
11/91	10200	TX	Office of Public	Texas-New Mexico Utility Counsel	Imprudence disallowance. Power Co.
12/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Year-end sales and customer adjustment, jurisdictional allocation.
1/92	89-783-E-C	WVA	West Virginia Energy Users Group	Monongahela Power Co.	Avoided cost, reserve margin, power plant economics.
3/92	91-370	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Interruptible rates, design, cost allocation.
5/92	91890	FL	Occidental Chemical Corp.	Fla. Power Corp.	Incentive regulation, jurisdictional separation, interruptible rate design.
6/92	4131-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Integrated resource planning, DSM.
9/92	920324	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Cost allocation, interruptible rates decoupling and DSM.
10/92	4132-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Residential conservation program certification.
10/92	11000	TX	Office of Public Utility Counsel	Houston Lighting and Power Co.	Certification of utility cogeneration project.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Direct)	Production cost savings from merger.
11/92	8469	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, revenue distribution.
11/92	920606	FL	Florida Industrial Power Users Group	Statewide Rulemaking	Decoupling, demand-side management, conservation, Performance incentives.
12/92	R-009 22378	PA	Armco Advanced Materials	West Penn Power	Energy allocation of production costs.
1/93	8179	MD	Eastalco Aluminum/ Westvaco Corp.	Potomac Edison Co.	Economics of QF vs. combined cycle power plant.
2/93	92-E-0814 88-E-081	NY	Occidental Chemical Corp.	Niagara Mohawk Power Corp.	Special rates, wheeling.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
3/93	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Surrebuttal)	Production cost savings from merger.
4/93	EC92 21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	GSU Merger prodcution cost savings
6/93	930055-EU	FL	Florida Industrial Power Users' Group	Statewide Rulemaking	Stockholder incentives for off-system sales.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers & Attorney General	Big Rivers Elec. Corp.	Prudence of fuel procurement decisions.
9/93	4152-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Cost allocation of pollution control equipment.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minn. Power Co.	Analysis of revenue req. and cost allocation issues.
4/94	93-465	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Review and critique proposed environmental surcharge.
4/94	4895-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co	Purchased power agreement and fuel adjustment clause.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Light Co.	Rev. requirements, incentive compensation.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue annualization, ROE performance bonus, and cost allocation.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Revenue requirements, ROE performance bonus, and revenue distribution.
1/95	94-332	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Environmental surcharge.
1/95	94-996-EL-AIR	OH	Industrial Energy Users of Ohio	Ohio Power Company	Cost-of-service, rate design, demand allocation of power
3/95	E999-CI	MN	Large Power Intervenor	Minnesota Public Utilities Comm.	Environmental Costs Of electricity
4/95	95-060	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Company	Six month review of CAAA surcharge.
11/95	I-940032	PA	The Industrial Energy Consumers of Pennsylvania	Statewide - all utilities	Direct Access vs. Poolco, market power.
11/95	95-455	KY	Kentucky Industrial	Kentucky Utilities	Clean Air Act Surcharge,
12/95	95-455	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Clean Air Act Compliance Surcharge.
6/96	960409-EI	FL	Florida Industrial	Tampa Electric Co.	Polk County Power Plant

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Power Users Group		Rate Treatment Issues.
3/97	R-973877	PA	PAIEUG.	PECO Energy	Stranded Costs & Market Prices.
3/97	970096-EQ	FL	FIPUG	Fla. Power Corp.	Buyout of QF Contract
6/97	R-973593	PA	PAIEUG	PECO Energy	Market Prices, Stranded Cost
7/97	R-973594	PA	PPLICA	PP&L	Market Prices, Stranded Cost
8/97	96-360-U	AR	AEEC	Entergy Ark. Inc.	Market Prices and Stranded Costs, Cost Allocation, Rate Design
10/97	6739-U	GA	GPSC Staff	Georgia Power	Planning Prudence of Pumped Storage Power Plant
10/97	R-974008 R-974009	PA	MIEUG PICA	Metropolitan Ed. PENELEC	Market Prices, Stranded Costs
11/97	R-973981	PA	WPII	West Penn Power	Market Prices, Stranded Costs
11/97	R-974104	PA	DII	Duquesne Light Co.	Market Prices, Stranded Costs
2/98	APSC 97451 97452 97454	AR	AEEC	Generic Docket	Regulated vs. Market Rates, Rate Unbundling, Timetable for Competition.
7/98	APSC 87-166	AR	AEEC	Entergy Ark. Inc.	Nuclear decommissioning cost estimates & rate treatment.
9/98	97-035-01	UT	DPS and CCS	PacifiCorp	Net Power Cost Stipulation, Production Cost Model Audit
12/98	19270	TX	OPC	HL&P	Reliability, Load Forecasting
4/99	19512	TX	OPC	SPS	Fuel Reconciliation
4/99	99-02-05	CT	CIEC	CL&P	Stranded Costs, Market Prices
4/99	99-03-04	CT	CIEC	UI	Stranded Costs, Market Prices
6/99	20290	TX	OPC	CP&L	Fuel Reconciliation
7/99	99-03-36	CT	CIEC	CL&P	Interim Nuclear Recovery
7/99	98-0453	WV	WVEUG	AEP & APS	Stranded Costs, Market Prices
12/99	21111	TX	OPC	EGSI	Fuel Reconciliation
2/00	99-035-01	UT	CCS	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
5/00	99-1658	OH	AK Steel	CG&E	Stranded Costs, Market Prices
6/00	UE-111	OR	ICNU	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
9/00	22355	TX	OPC	Reliant Energy	Stranded cost

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/00	22350	TX	OPC	TXU Electric	Stranded cost
10/00	99-263-U	AR	Tyson Foods	SW Elec. Coop	Cost of Service
12/00	99-250-U	AR	Tyson Foods	Ozarks Elec. Coop	Cost of Service
01/01	00-099-U	AR	Tyson Foods	SWEPCO	Rate Unbundling
02/01	99-255-U	AR	Tyson Foods	Ark. Valley Coop	Rate Unbundling
03/01	UE-116	OR	ICNU	PacifiCorp	Net Power Costs
6/01	01-035-01	UT	DPS and CCS	PacifiCorp	Net Power Costs
7/01	A.01-03-026	CA	Roseburg FP	PacifiCorp	Net Power Costs
7/01	23550	TX	OPC	EGSI	Fuel Reconciliation
7/01	23950	TX	OPC	Reliant Energy	Price to beat fuel factor
8/01	24195	TX	OPC	CP&L	Price to beat fuel factor
8/01	24335	TX	OPC	WTU	Price to beat fuel factor
9/01	24449	TX	OPC	SWEPCO	Price to beat fuel factor
10/01	20000-EP 01-167	WY	WIEC	PacifiCorp	Power Cost Adjustment Excess Power Costs
2/02	UM-995	OR	ICNU	PacifiCorp	Cost of Hydro Deficit
2/02	00-01-37	UT	CCS	PacifiCorp	Certification of Peaking Plant
4/02	00-035-23	UT	CCS	PacifiCorp	Cost of Plant Outage, Excess Power Cost Stipulation.
4/02	01-084/296	AR	AEEC	Entergy Arkansas	Recovery of Ice Storm Costs
5/02	25802	TX	OPC	TXU Energy	Escalation of Fuel Factor
5/02	25840	TX	OPC	Reliant Energy	Escalation of Fuel Factor
5/02	25873	TX	OPC	Mutual Energy CPL	Escalation of Fuel Factor
5/02	25874	TX	OPC	Mutual Energy WTU	Escalation of Fuel Factor
5/02	25885	TX	OPC	First Choice	Escalation of Fuel Factor
7/02	UE-139	OR	ICNU	Portland General	Power Cost Modeling
8/02	UE-137	OP	ICNU	Portland General	Power Cost Adjustment Clause
10/02	RPU-02-03	IA	Maytag, et al	Interstate P&L	Hourly Cost of Service Model
11/02	20000-Er 02-184	WY	WIEC	PacifiCorp	Net Power Costs, Deferred Excess Power Cost
12/02	26933	TX	OPC	Reliant Energy	Escalation of Fuel Factor
12/02	26195	TX	OPC	Centerpoint Energy	Fuel Reconciliation
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	UE-134	OR	ICNU	PacifiCorp	West Valley CT Lease payment

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	26186	TX	OPC	SPS	Fuel Reconciliation
2/03	UE-02417	WA	ICNU	PacifiCorp	Rate Plan Stipulation, Deferred Power Costs
2/03	27320	TX	OPC	Reliant Energy	Escalation of Fuel Factor
2/03	27281	TX	OPC	TXU Energy	Escalation of Fuel Factor
2/03	27376	TX	OPC	CPL Retail Energy	Escalation of Fuel Factor
2/03	27377	TX	OPC	WTU Retail Energy	Escalation of Fuel Factor
3/03	27390	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27511	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27035	TX	OPC	AEP Texas Central	Fuel Reconciliation
05/03	03-028-U	AR	AEEC	Entergy Ark., Inc.	Power Sales Transaction
7/03	UE-149	OR	ICNU	Portland General	Power Cost Modeling
8/03	28191	TX	OPC	TXU Energy	Escalation of Fuel Factor
11/03	20000-ER -03-198	WY	WIEC	PacifiCorp	Net Power Costs
2/04	03-035-29	UT	CCS	PacifiCorp	Certification of CCCT Power Plant, RFP and Bid Evaluation
6/04	29526	TX	OPC	Centerpoint	Stranded cost true-up.
6/04	UE-161	OR	ICNU	Portland General	Power Cost Modeling
7/04	UE-032065	WA	ICNU	PacifiCorp	Power Cost modeling, Jurisdictional Allocation
7/04	UM-1050	OR	ICNU	PacifiCorp	Jurisdictional Allocation
10/04	15392-U 15392-U	GA	Calpine	Georgia Power/ SEPCO	Fair Market Value of Combined Cycle Power Plant
12/04	04-035-42	UT	CCS	PacifiCorp	Net power costs

PUBLIC UTILITY COMMISSION OF OREGON

UE 149

STAFF TESTIMONY

OF

MAURY GALBRAITH

In the Matter of
PORTLAND GENERAL ELECTRIC
Annual Adjustments to Schedule 125

Redacted Version

July 2, 2003

A. Staff recommends that the Commission adopt the 2.4% escalation rate forecast of the delivered cost of coal for Boardman for 2004. Exhibit Staff 104, Galbraith/1 shows Staff's forecast of Boardman coal costs. Using this forecast of coal costs results in a $5.1 million decrease in forecasted NVPC for 2004. Exhibit Staff 105, Galbraith/1-4 provides the MONET run used to calculate the impact on NVPC. Staff recommends that the commission use these coal costs as the default placeholder in MONET. PGE should be allowed to update the delivered cost of coal for Boardman with known and measurable contract costs only if the company has signed new commodity or rail contracts, and provides Staff and interveners with supporting data and analyses, prior to September 19, 2003. This date is twenty business days prior to the date of the expected Commission order in this docket. This should allow time for parties to review any newly signed contracts and to make recommendations to the Commission.

DISALLOWANCE OF ABOVE MARKET COST OF 2001 TRANSACTIONS

Q. PLEASE DESCRIBE THE CONTRACTS EXAMINED BY STAFF.

A. Staff identified eight power contracts that deserved close scrutiny. These eight contracts are identified in Table 2.

Table 2. PGE's 2004 Contracts Examined by Staff.

Counter Party	Deal #	Transaction Date
Morgan Stanley Capital Group, Inc.	42205	02/24/2003
Sempra Energy Trading Corp.	42061	02/21/2003
Morgan Stanley Capital Group, Inc.	41363	02/12/2003
Morgan Stanley Capital Group, Inc.	13651	02/06/2002
El Paso Merchant Energy, L.P.	3593	08/16/2001
Morgan Stanley Capital Group, Inc.	3497	08/09/2001
Morgan Stanley Capital Group, Inc.	2765	06/12/2001
Mirant Americas Energy Marketing, L.P.	1270	01/29/2001

The first three contracts (Deal Nos. 42205, 42061, and 41363) provide 75 megawatts of on-peak delivery for the fourth quarter of 2004 and were all signed 19 months prior to the October 1, 2004 start dates. The fourth contract (Deal No. 13651) provides 50 megawatts of off-peak delivery for calendar year 2004 and was signed 22 months prior to its start date. The last four contracts (Deal Nos. 3593, 3497, 2765, and 1270) provide 100 megawatts of flat delivery for calendar years 2004-2006 and were signed by PGE between 28 and 35 months prior to the January 1, 2004 start dates.

Q. WHY DO THESE CONTRACTS DESERVE CLOSER SCRUTINY?

A. PGE signed each of these contracts more than eighteen months prior to delivery. In testimony in docket UE 115, PGE indicated that it begins to fill its net open position 18 months prior to delivery. The eighteen-month benchmark was set to reflect the point in time when the term power market typically becomes liquid. I discussed PGE's advance purchasing rule-of-thumb in testimony in docket UE 139. Exhibit Staff/106, Galbraith/1-5 is a copy of Staff's Direct Testimony in UE 139.

<u>FOURTH QUARTER 2004 AND CALENDAR YEAR 2004 TRANSACTIONS</u>

Q. WHY DID PGE ENTER INTO THE FOURTH QUARTER 2004 AND CALENDAR YEAR 2004 DEALS?

A. In PGE Response to OPUC Data Request Nos. 40 and 46, the company explained the rationale for signing these four contracts between 19 and 22 months prior to delivery. PGE stated:

> "Prior to the 2000-2001 energy crises, we could expect market liquidity for a 12-month block of power to begin about 18 months in advance. We noted this in our power cost testimony in UE-115. However, wholesale power markets have become much more illiquid since 2000 so that the liquidity for a calendar

purchase now occurs much closer than 18 months. Indeed, liquidity for such products may not appear until just before delivery. Making purchases only 18 months or closer to delivery (or more to the point, when market liquidity is clearly evident) would increase risk to PGE and our customers." PGE Response to Staff Data Request Nos. 40 and 46.

In Data Response No. 46 the company stated,

"As described above, market liquidity in the aftermath of the energy crisis has become spotty, with opportunities opening and closing, sometimes further out than 18 months before delivery, and sometimes only much closer to delivery. We believe it is prudent to layer in power when the price is reasonable prior to 18 months before delivery." PGE Response to Staff Data Request No. 46.

Q. WAS THE MARKET FOR FOURTH QUARTER 2004 AND CALENDAR YEAR 2004 PRODUCTS LIQUID AT THE TIME PGE SIGNED THESE DEALS?

A. No. The company has indicated that the market for these products was not liquid at the time it signed the deals. PGE Response to Staff Data Request Nos. 40 and 46.

Q WHAT IS STAFF'S REACTION TO THESE FINDINGS?

A. Staff agrees that the deterioration in market liquidity undermined the eighteen-month guideline for beginning purchases. Spreading the needed purchases out over time to reduce price risk, instead of waiting until the market becomes liquid just before delivery, makes sense. But PGE's defense of the fourth quarter 2004 and calendar year 2004 deals is weak. PGE's justification of the fourth quarter 2004 and calendar year 2004 contract prices is that they were in line with PGE's forward price curves at the time the deals were done. PGE Response to OPUC Staff Data Request No. 46. Yet, at the time the deals were done, the market was illiquid. This means that the relevant portion of PGE's forward price curve was either based on a limited number of transactions or set without any supporting trades. This type of justification seems to reduce to the contract prices being reasonable simply because the traders who set the forward price curve said so.

Q. WHAT IS STAFF'S RECOMMENDATION TO THE COMMISSION WITH RESPECT TO THE FOURTH QUARTER 2004 CALENDAR YEAR 2004 CONTRACTS?

A. Staff agrees that the eighteen-month guideline should not be applied and that it would not have been prudent to delay making the purchases until shortly before delivery. While PGE's support for the deals is limited (i.e., based only on consistency with forward curves developed in an illiquid market), Staff is unable to argue for a different pricing strategy and proxy price for these deals. These findings lead Staff to conclude that PGE should be allowed to recover the full amount of the fourth quarter 2004 calendar year 2004 contracts.

<u>2001 TRANSACTIONS</u>

Q. DOES PGE DISCUSS THE '2001 TRANSACTIONS' IN DIRECT TESTIMONY?

A. Yes. At UE 149/PGE 200/Lobdell/27-28 the company carefully distinguishes the deals signed in 2001 from those signed in 2002 and 2003. The company suggests that the transactions done in 2001 are structured products, whereas the deals signed in 2002 and 2003 are standard term purchases.

Q. WHY DOES THE COMPANY MAKE THIS DISTINCTION?

A. The company believes that structured products and standard terms purchases should be evaluated in different ways. Standard term purchases are to be compared to 'like transactions', whereas structured products are to be compared to alternative products and services. See UE 149/PGE 200/Lobdell/21-22.

Q. DOES STAFF AGREE WITH PGE THAT THE TRANSACTIONS DONE IN 2001 ARE STRUCTURED PRODUCTS?

A. Not completely. PGE defines a standard term purchase as a deal: (1) done through a broker, (2) for a block product that has little, if any, shaping, and (3) that usually has a term of one year or less. In contrast, PGE defines a structured purchase as a deal: (1) done on a bilateral basis, (2) for a shaped product with unique characteristics, and (3) that can cover unusual periods of time. See UE 149/PGE 200/Lobdell/21-22. On perhaps the most important criterion, shaping and unique characteristics, the '2001 Transactions' look more like standard term purchases than structured products. All four of the transactions are 25 MW block products with flat delivery (i.e., no shaping).

Q. DID PGE'S STRUCTURING GROUP ANALYZE AND EXECUTE THE 2001 TRANSACTIONS?

A. No. In PGE Response to OPUC Data Request No. 49, the company explained that the Structuring Group was formalized in March of 2001. The first '2001 Transaction' (Deal No. 1270) was done before this group was created. The Structuring Group was not involved in analyzing the other '2001 Transactions' (Deal Nos. 2765, 3497, and 3593) because the group was initially tasked with developing modeling tools for evaluating non-standard products.

Q. DOES STAFF AGREE WITH PGE THAT STRUCTURED PRODUCTS AND STANDARD TERM PURCHASES SHOULD BE EVALUATED IN DIFFERENT WAYS?

A. No. All purchases, both standard term purchases and structured products, should be compared to the available alternatives. A liquid market with many 'like transactions' simply represents a readily available alternative. For block products with little or no shaping a comparison with the market alternative is straightforward. The difficultly with structured products is that their unique characteristics often make a comparison with the market alternative difficult. In either case, the proper method of evaluation is to compare the product under consideration to the available alternatives. Concern raises when no comparison is made or when there are too few alternatives.

Q. DID STAFF REQUEST INFORMATION FROM PGE IN UE 149 REGARDING ITS RATIONALE FOR COMMITTING TO THE 2001 TRANSACTIONS 28 TO 35 MONTHS IN ADVANCE OF DELIVERY?

A. Yes. In PGE Response to OPUC Data Request No. 40, the company identified the long-term availability of supply as a primary concern. The company also explained, that at the time the deals where done, the company's expectations of market prices indicated that the contract prices were reasonable.

Q. DID PGE PROVIDED ANY STUDIES OR ANALYSES DONE AT THE TIME THE 2001 CONTRACTS WERE SIGNED THAT INDICATE SUPPLY WOULD BE TIGHT IN 2004-2006?

A. No.

Q. DID PGE PROVIDED ANY STUDIES OR ANALYSES DONE AT THE TIME THE 2001 CONTRACTS WERE SIGNED THAT COMPARED THE '2001 TRANSACTIONS' TO OTHER ALTERNATIVES?

A. No.

Q. DOES PGE'S RATIONALE FOR SIGNING THESE CONTRACTS 28 TO 35 MONTHS IN ADVANCE OF DELIVERY SATISFY THE REASONABLE PERSON STANDARD USED BY THE COMMISSION TO JUDGE THE PRUDENCE OF COMPANY ACTIONS?

A. No. First, in the first half of 2001, the company's expectation was that the market for term products would begin to be liquid twelve to eighteen months prior to delivery. PGE's eighteen-month rule-of-thumb for advance purchasing represented a measured, reasonable approach to filling the company's net open position. Second, in early 2001 the market for 2004-2006 power products was illiquid. The relevant portion of PGE's forward price curve was either based on a limited number of transactions or set without any supporting trades. The lack of reliable price information dictated a slow cautionary approach. Third, the contracts' length of delivery is a unique characteristic that makes accurate pricing a challenge. The company should have conducted analyses that compared the '2001 Transactions' to potential alternatives. The unique delivery term dictated through analysis. Finally, the company has indicated that long-term supply availability was a concern in early 2001. However, the company has not provided any studies or analyses that support this assertion. Staff concludes that a reasonable person would have waited for reliable price information and compared these contracts to other alternatives before beginning to fill the company's net open positions for 2004-2006. Staff concludes that PGE's decisions to commit to the '2001 Transactions' were imprudent.

Q. WHAT IS THE RESULT OF CALCULATING A DISALLOWANCE USING THE SAME PROXY PRICE METHODOLOGY THE COMMISSION USED LAST YEAR IN COMMISSION ORDER NO. 02-772?

A. The result would be an $11.1 million disallowance. This calculated disallowance uses the average of the monthly prices for 2004 from PGE's forward price curve for flat products from July 1, 2002 (i.e., eighteen months prior to the start of delivery) as a proxy price. Exhibit Staff/107, Galbraith/1 shows the details of the disallowance calculation.

Q. IS USING THE AVERAGE OF THE MONTHLY PRICES IN PGE'S JULY 1, 2002 FORWARD CURVE AN APPROPRIATE CHOICE OF A PROXY PRICE?

A. No. While the Commission used an 18-month proxy price to re-price the disputed transactions included in the 2003 RVM (Order No. 02-772), there are at least two reasons why this approach is inappropriate for re-pricing the '2001 Transactions' included in the 2004 RVM. First, with the recent deterioration of the wholesale power markets, the 18-month benchmark no longer reflects the point in time when the wholesale market begins to achieve liquidity. The monthly prices for 2004 reported in PGE's July 1, 2002 forward curve were likely based on a limited number of transactions or set without any supporting trades. It would be inappropriate to calculate a proxy price using reported prices of 'thinly traded' products. Second, the '2001 Transactions' are all three-year deals. It would be inappropriate to re-price each of these transactions as though they were three one-year deals. There is added value to the delivery in the second and third years that should be reflected in the proxy price.

Q. WHAT IS THE PROPER METHOD TO REMOVE THE IMPACT OF THESE IMPRUDENT ACTIONS FROM PGE'S FORECAST OF 2004 NVPC?

A. The proper approach is to re-price the '2001 Transactions' using an accurate price for a comparable power product. However, the unique delivery term of the '2001 Transactions' makes finding an accurate price problematic. The wholesale power market for 2004 products is only intermittently liquid and the market for 2005 and 2006 products continues to be illiquid.

Q. WHAT PROXY PRICE DOES STAFF RECOMMEND THE COMMISSION USE TO RE-PRICE THE '2001 TRANSACTIONS'?

A. Staff recommends that the Commission use the price in Deal No. 3497 as a proxy price. The Deal No. 3497 price is the lowest price of the '2001 Transactions'. This represents a reasonable proxy price. In other words, although all four contracts were the result of imprudent action by PGE, Staff recommends that the Commission use the lowest price deal to re-price the three higher priced deals.

Q. WHAT IS THE OVERALL IMPACT ON PGE'S FORECAST OF 2004 NVPC OF RE-PRICING THE '2001 TRANSACTIONS' USING THE DEAL NO. 3497 PRICE?

A. Staff's recommended approach results in a disallowance of $7.2 million. Exhibit Staff/108, Galbraith/1 shows the details of the calculation.

Q. DOES STAFF RECOMMEND THAT THE COMMISSION USE THE DEAL NO. 3497 PRICE TO RE-PRICE THE '2001 TRANSACTIONS' IN THE 2005 AND 2006 RVM PROCEEDINGS?

A. Yes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY ON THE '2001 TRANSACTIONS'?

A. Yes.

Q. DOES STAFF HAVE ANY OTHER ADJUSTMENTS TO PROPOSE IN UE 149?

A. No.

Q. DOES THIS CONCLUDE YOUR UE 149 TESTIMONY?

A. Yes.

HARDY MYERS
Attorney General

PETER SHEPHERD
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

November 5, 2004

TRACI KIRKPATRICK
ADMINISTRATIVE LAW JUDGE
OREGON PUBLIC UTILITY COMMISSION
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RE: RATEMAKING TREATMENT OF CAPACITY TOLLING AGREEMENTS IN PORTLAND GENERAL ELECTRIC'S 2005 RESOURCE VALUATION MECHANISM (DOCKET UE 161)

Dear Judge Kirkpatrick:

On November 3, 2004, Portland General Electric (PGE) filed a draft MONET run in Docket UE 161. Staff has reviewed the updates made in the November 3rd draft MONET run and has identified the ratemaking treatment of capacity tolling agreements as an issue to bring to your attention. Because of Staff's concerns we request a pre-hearing conference be scheduled next week to further discuss this issue.

As PGE indicated in its cover letter accompanying the November 3rd draft MONET run, the company recently signed two new capacity contracts pursuant to its 2002 Integrated Resource Plan and the associated Request for Proposals. Both of these capacity contracts have delivery periods in 2005 and future years. As a result, PGE has modeled the dispatch of these contracts in the November 3rd draft MONET run.

The cost for each of these contracts is comprised of a capacity charge and an energy charge. PGE pays the capacity charge on a monthly basis whether or not it actually schedules any delivery of energy. For calendar year 2005, PGE estimates that the capacity payments for these two contracts will total $2.174 million. PGE pays the energy charge on a monthly basis for each megawatt-hour (MWh) of delivered energy. Based on its MONET modeling of the dispatch of these contracts, PGE estimates for ratemaking purposes, that it will not dispatch (i.e., not actually use) these contracts in 2005. Therefore, for calendar year 2005 the energy payments for these two contracts are estimated to be zero dollars. Consequently, the total cost of these two contracts that PGE has included in the 2005 RVM is $2.174 million.

The benefit of these contracts is comprised of the company's ability to reduce net variable power costs when market prices of electricity and natural gas make the dispatch of these contracts profitable. Both of these capacity tolling agreements have terms and conditions that suggest that economic dispatch will only occur during periods where the spread between market electricity prices and natural gas prices is extreme. The company, however, models net variable power costs in the MONET model on an expected price basis. Under normal, or expected, price conditions the likelihood that these capacity contracts will be economic to dispatch is low – hence in MONET energy payments modeled to be zero dollars in 2005. The uncertainty surrounding the dispatch of these capacity contracts complicates their treatment in PGE's rates.

Staff believes that the ratemaking treatment implied in PGE's November 3rd draft MONET run creates a significant mismatch between ratepayer costs and benefits. For 2005, PGE is asking its customers to pay $2.174 million in costs. In exchange, because rates are set on an expected price basis, the only benefit that customers could possibly receive is if an extreme price event occurs and the company or an intervening party anticipates the event and files an application for a power cost deferral. Absent that unlikely situation, the benefits of these capacity tolling agreements fall entirely to PGE's shareholders, despite the $2.174 million included in customers' rates.

Permanent remedies to this mismatch of ratepayer costs and benefits include: (1) Abandoning expected price modeling in MONET and implementing expected net variable power cost modeling, or (2) Establishing a permanent power cost adjustment mechanism that appropriately matches costs and benefits on a long-run basis. The first alternative involves an enhancement to MONET. Implementing this alternative in the 2006 RVM would require the consent of PGE, Staff, the Citizens' Utility Board, and the Industrial Customer's of Northwest Utilities (see Order 03-535 adopting stipulations in Docket UE 149) and significant analytical work. The second alternative is being considered in Docket UE 165.

To remedy this mismatch in the 2005 RVM, Staff recommends that the Commission remove the $2.174 million in capacity payments from PGE's net variable power costs. Under this approach, shareholders would bear all of the costs and receive all of the benefits of these contracts during 2005. This has the effect of matching the 2005 costs and benefits. It also reflects the fact PGE has traditionally borne the risk of extreme price events between rate cases. Staff is willing to consider other remedies that PGE or intervenors may propose.

As you know, PGE files its final MONET run on November 10, 2004. We request a pre-hearing conference next week to further discuss this issue.

Sincerely,

David B. Hatton
Assistant Attorney General
Regulated Utility & Business Section

DBH:nal/GENK7978.DOC

cc: UE 161 Service List

PGE

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Douglas C. Tingey
Assistant General Counsel

November 9, 2004

Traci Kirkpatrick
Administrative Law Judge
Oregon Public Utility Commission
P.O. Box 2148
Salem OR 97308-2148

Re: Docket No. UE 161 – Portland General Electric's 2005 Resource Valuation Mechanism

Dear Judge Kirkpatrick:

On November 5, 2004, counsel for Oregon Public Utility Commission Staff ("Staff") sent you a letter attempting to raise an issue regarding the ratemaking treatment of two capacity tolling agreements. That letter argued Staff's position on the issue, and this letter is sent to respond to that argument. In sum, as set forth below, Staff's letter is ill-timed and founded on a misunderstanding of capacity agreements and their Commission-approved ratemaking. Portland General Electric Company ("PGE") requests that Staff's request be summarily denied.

Capacity contracts have been included in every RVM proceeding. The Resource Valuation Mechanism ("RVM") was created and adopted by the Commission as part of a PGE general rate case, Docket No. UE 115, in 2001. At that time, as part of the implementation of Senate Bill 1149, the Oregon Public Utility Commission ("Commission") adopted the RVM proceeding to annually value and reset net variable power costs and determine the amount of any credit or charge for those customers opting for direct access. In creating the RVM process, PGE's costs were divided into two groups – net variable power costs that were included in the RVM update process, and fixed costs not included in the RVM process. PGE's power costs included two capacity contracts, one entered into in 1992 with Washington Water Power, and one entered into in 1995 with EWEB. Both of those capacity contracts were included in the RVM net variable power costs for ratemaking. Those capacity contracts were also included in RVM net variable power costs in the 2003 RVM proceeding (UE 139) and the 2004 RVM proceeding (UE 149). They are also included in net variable power costs in this 2005 RVM proceeding, and Staff has stipulated that the costs were proper and should be included in rates. Contrary to Staff's assertion, there is no issue as to the ratemaking treatment of capacity agreements in RVM proceedings.

The capacity contracts were entered into as part of the IRP process. In LC 33, the recently concluded PGE least cost planning docket, PGE's Integrated Resource Plan ("IRP") was subjected to intense scrutiny and numerous revisions over a two-plus year period. The need for capacity was included in that discussion starting with the August 2002 IRP filing. On July 20, 2004, the Commission issued an Order acknowledging PGE's Integrated Resource Final Action Plan. Ten action items were specifically acknowledged, including the following:

5. Acquire up to 50 MWa of baseload energy tolling in place of fixed price PPAs if required, *and 400 MW of tolling capability for peak purposes.* (Emphasis added.)

As part of the least cost planning procedure, PGE had issued a Request for Proposals ("RFP") seeking capacity tolling agreements. Staff was involved in and familiar with the results of that RFP. Consistent with the Commission's acknowledgment in LC 33, PGE entered into the two capacity tolling agreements that Staff questions here.

The two contracts are for a total of 400 MW, as called for by the acknowledged IRP. PGE has done exactly what its Commission-acknowledged least cost plan directed. The Commission itself said, in the LC 33 order that: "In ratemaking proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions that are consistent with acknowledged least-cost plans."

PGE acted timely and consistently with the Commission acknowledged Least Cost Plan, acquired these capacity resources in the manner directed by that plan, and included them in RVM net variable power costs like other capacity contracts. Notwithstanding this, Staff has asked the Commission to deny cost recovery for these contracts. Such a result would not be proper, fair, just or reasonable, or promote confidence in the regulatory process.

Capacity contracts are for reliability. Staff misconstrues or misunderstands the function and purpose of capacity agreements. PGE and other utilities enter into capacity agreements so they can reliably provide power to customers. Capacity contracts provide the right for the utility to receive, when needed, energy up to a specified amount. In those hours or days when there may not be sufficient resources in the region to meet all demands, having the ability to draw on capacity contracts helps to keep the lights on for PGE customers, even if there are blackouts elsewhere in the region due to insufficient energy. That is the reason PGE enters into capacity contracts.

Staff's theory that capacity contracts are for shareholder benefit is incorrect. They are for customer benefit in the form of reliable electric service. PGE customers expect, and deserve, reliable service, including during those times when energy resources may be short in the region. Capacity contracts are one necessary component of providing reliable service to customers. The costs of those capacity contracts are properly included in net variable power costs in the RVM, as they have been since the creation of the RVM process.

Staff's proposed remedy is inconsistent with its Stipulation in UE 149. In UE 149, PGE's 2004 RVM proceeding, all parties entered into a Stipulation settling all issues in the docket. That Stipulation was adopted and approved by the Commission in Order No. 03-535, issued August 29, 2003. In that Stipulation the parties agreed that, other than specifically identified enhancements, no party "will propose in the 2005 or 2006 RVM proceeding any enhancements to the Monet model used in the Final RVM Filing, unless the Monet model is modified through a general rate case or by the unanimous agreement of the Parties." In its letter Staff posits that one remedy to its perceived problem would be implementing expected net variable power cost modeling, an enhancement to Monet. Staff recognizes that implementing that change in this docket or in the 2006 RVM proceeding would require the consent of PGE, Staff, the Citizens' Utility Board, and the Industrial Customers of Northwest Utilities. Yet, Staff is attempting to indirectly and partially do what it has agreed not to do directly. Staff's real issue seems to be that they do not like the way capacity contracts are modeled by Monet. Staff's request is a backdoor attempt to undo the Stipulation in UE 149 and that request is inappropriate.

Conclusion. Staff has attempted, in the eleventh hour of this docket, to raise an issue that is well settled – the ratemaking treatment of capacity contracts. Capacity contracts have been included in net variable power costs since the RVM process was created. Staff's request is based on an erroneous view of the nature and purpose of capacity contracts. Staff's request is also inconsistent with its Stipulation in UE 149. These capacity contracts were entered into in conjunction with PGE's Least Cost Plan as acknowledged by the Commission. They are properly included in net variable power costs in this RVM.

The final RVM filing in this docket will be made very soon. From that filing customer rates will be set for next year, and the size of the credit for customers choosing direct access will be determined and posted on PGE's website on November 15, 2004. That process should not be stalled, or made uncertain, because of this last minute filing by Staff. Staff's request should be summarily denied. If, however, the Commission determines that further proceedings are necessary, PGE requests that a hearing be set, with the Commissioners present, the week of November 22, 2004, so that an order can be issued as soon thereafter as possible.

Sincerely,

DCT:am

cc: UE 161 Service List

ISSUED: November 16, 2004

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 161

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Adjustments to Schedule 125 (2005 RVM Filing).	)))))))	PREHEARING CONFERENCE MEMORANDUM

On November 5, 2004, Public Utility Commission of Oregon (Commission) Staff (Staff) requested a prehearing conference to discuss concerns about the ratemaking treatment of capacity tolling agreements raised upon review of Portland General Electric's (PGE) draft MONET run November 3, 2004. As PGE was scheduled to file a final MONET run on November 10, 2004, Staff requested that a prehearing conference be held as soon as possible. PGE filed a letter on November 9, 2004, opposing Staff's request for an investigation of capacity tolling agreement ratemaking.

On November 10, 2004, a prehearing conference was held in Salem, Oregon. Appearances were entered as follows: David B. Hatton, attorney, appeared on behalf of Commission Staff; Doug Tingey, attorney, appeared on behalf of Portland General Electric Company (PGE); Matthew Perkins, attorney, appeared by telephone on behalf of the Industrial Customers of Northwest Utilities (ICNU); Brad Van Cleve, attorney, also appeared by telephone on behalf of ICNU; and Bob Jenks, attorney, appeared by telephone on behalf of Citizens' Utility Board of Oregon (CUB).

After preliminary matters were addressed, conference participants went off the record to discuss how to proceed. Back on the record, Mr. Hatton represented that the conference participants agreed that no further action by the Commission was necessary in this docket and that the final MONET run would be filed as scheduled. Instead, parties agreed to work informally outside of a contested case proceeding to draft language regarding the modeling of capacity tolling agreements, with the intent to present such language in PGE's next general rate case filing. Should efforts be unsuccessful, however, Staff indicated it would consider filing a deferred accounting request with the Commission, prior to the end of this year, to address the capacity tolling agreements at issue for 2005.

Dated this 16th day of November, 2004, at Salem, Oregon.

Traci A. G. Kirkpatrick
Administrative Law Judge

Exhibit ICNU/105
Comparison of 2006 Monet to 2004 Actual Hydro Hourly Generation (MW)

	2006 Monet				Actual 2004			
	Max	Min	Avg. mW	Std. Dev.	Max	Min	Avg. mW	Std. Dev.
Jan	*772*	*407*	*681*	85	933	139	597	185
Feb	*757*	*339*	*642*	106	952	222	555	176
Mar	*726*	*346*	*563*	145	894	216	527	161
Apr	*711*	*351*	*603*	103	837	179	508	164
May	*688*	*453*	*618*	53	805	157	516	178
June	*675*	*412*	*610*	56	819	112	538	181
July	*593*	*246*	*495*	80	754	100	395	169
Aug	*607*	*214*	*440*	138	865	80	441	201
Sep	*592*	*213*	*352*	123	774	106	419	169
Oct	*599*	*237*	*436*	142	781	109	438	163
Nov	*691*	*301*	*567*	113	929	144	506	170
Dec	*767*	*344*	*630*	141	937	132	633	181
Average	682	322	553	107	857	141	506	175
Difference from 2004	-175	181	47	-68				

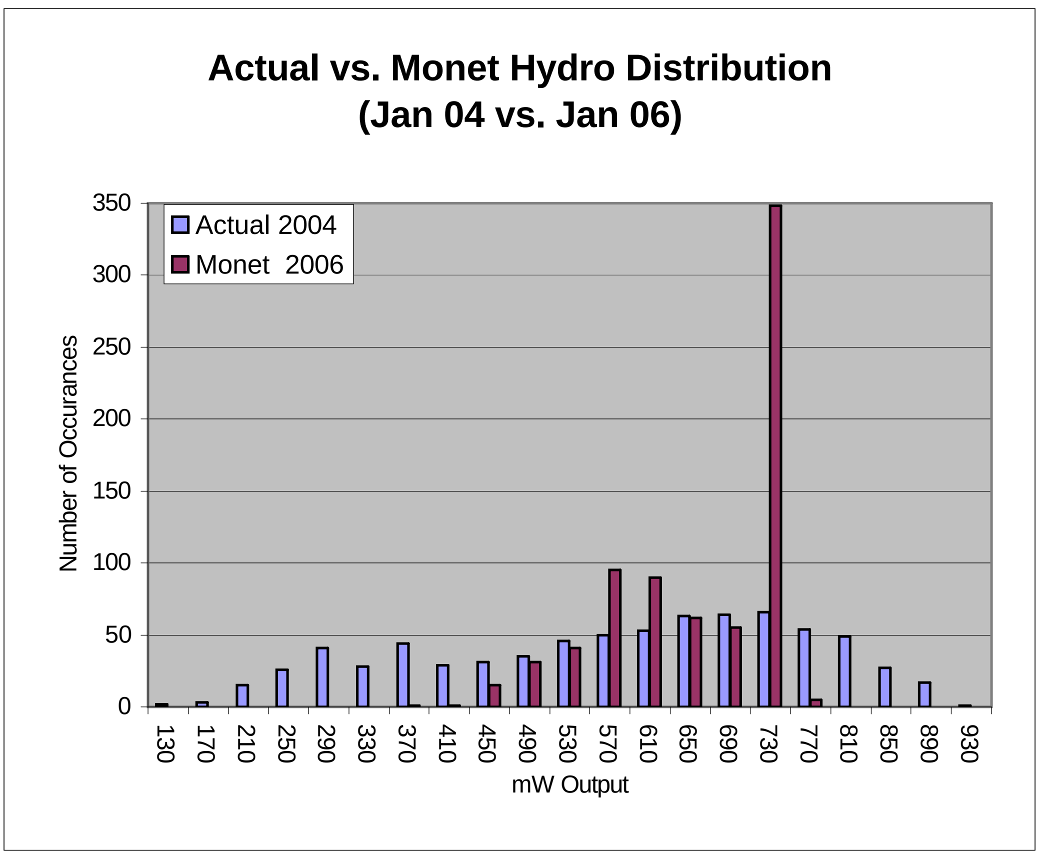

Exhibit ICNU/106
Savings from Allocation of Reserves to Beaver - August 2006

Max Price 61 Make Up purchases
MinPrice
Cost mW 75 53

Diagnostic Report - Resource Energy By Hour

Year	Month	Day of Month	Date	Day of Week	Hour (Monet)	Hour Ending	**Total Hydro**	Beaver Units 1-7	Beaver Unit 8	Coyote Off - Fire Auxiliary Boiler	Coyote in Extraction Steam Mode - Incremental	Coyote - Fire Auxiliary Boiler to Increase Power	Coyote Misting	Coyote Duct Firing	**Total Gas**	Marginal Cost	Beaver Units 1-7	Coyote in Extraction Steam Mode - Incremental	Spin Res on Coyote	Make Up purchases	Cost Savings	Cost Increse	
																	61		**Monthly Total**		**1,729,889**	**1,454,658**	**275,232**
2006	Aug	1	08/01/06	Tuesday	0	1	**424**	0	0	0	211	0	0	0	**211**	54.49	0		0	0	0	0	
2006	Aug	1	08/01/06	Tuesday	1	2	**222**	0	0	0	211	0	0	0	**211**	53.35	0		0	0	0	0	
2006	Aug	1	08/01/06	Tuesday	2	3	**214**	0	0	0	211	0	0	0	**211**	51.65	0		0	242	0	12481	
2006	Aug	1	08/01/06	Tuesday	3	4	**214**	0	0	0	211	0	0	0	**211**	51.18	0		0	242	0	12367	
2006	Aug	1	08/01/06	Tuesday	4	5	**214**	0	0	0	211	0	0	0	**211**	51.18	0		0	242	0	12367	
2006	Aug	1	08/01/06	Tuesday	5	6	**214**	0	0	0	211	0	0	0	**211**	53.79	0		0	0	0	0	
2006	Aug	1	08/01/06	Tuesday	6	7	**339**	110	0	0	215	0	0	0	**325**	65.11	87		0	0	0	0	
2006	Aug	1	08/01/06	Tuesday	7	8	**435**	160	0	0	215	0	0	0	**375**	66.82	61		75	0	4589	0	
2006	Aug	1	08/01/06	Tuesday	8	9	**470**	284	0	0	215	0	0	0	**499**	68.24	61		75	0	4589	0	
2006	Aug	1	08/01/06	Tuesday	9	10	**497**	408	0	0	215	0	0	0	**622**	68.87	61		75	0	4589	0	
2006	Aug	1	08/01/06	Tuesday	10	11	**525**	445	0	0	215	0	0	0	**659**	69.18	61		75	0	4589	0	
2006	Aug	1	08/01/06	Tuesday	11	12	**555**	445	0	0	215	0	0	0	**659**	69.98	61		75	0	4589	0	
2006	Aug	1	08/01/06	Tuesday	12	13	**550**	445	0	0	215	0	0	0	**659**	69.98	61		75	0	4589	0	
2006	Aug	1	08/01/06	Tuesday	13	14	**565**	445	0	0	215	0	0	0	**659**	71.33	61		75	0	4589	0	
2006	Aug	1	08/01/06	Tuesday	14	15	**580**	445	0	0	215	0	0	0	**659**	73.46	61		75	0	4589	0	
2006	Aug	1	08/01/06	Tuesday	15	16	**594**	445	0	0	215	0	0	0	**659**	75.51	61		75	0	4589	0	
2006	Aug	1	08/01/06	Tuesday	16	17	**600**	445	0	0	215	0	0	0	**659**	77.97	61		75	0	4589	0	
2006	Aug	1	08/01/06	Tuesday	17	18	**591**	445	0	0	215	0	0	0	**659**	78.44	61		75	0	4589	0	
2006	Aug	1	08/01/06	Tuesday	18	19	**557**	445	0	0	215	0	0	0	**659**	76.06	61		75	0	4589	0	
2006	Aug	1	08/01/06	Tuesday	19	20	**530**	445	0	0	215	0	0	0	**659**	75.12	61		75	0	4589	0	
2006	Aug	1	08/01/06	Tuesday	20	21	**518**	445	0	0	215	0	0	0	**659**	71.64	61		75	0	4589	0	
2006	Aug	1	08/01/06	Tuesday	21	22	**472**	244	0	0	215	0	0	0	**458**	66.20	61		75	0	4589	0	
2006	Aug	1	08/01/06	Tuesday	22	23	**457**	0	0	0	215	0	0	0	**215**	61.60	0		0	0	0	0	
2006	Aug	1	08/01/06	Tuesday	23	24	**408**	0	0	0	211	0	0	0	**211**	56.87	0		0	0	0	0	
2006	Aug	2	08/02/06	Wednesday	0	1	**397**	0	0	0	211	0	0	0	**211**	54.49	0		0	0	0	0	
2006	Aug	2	08/02/06	Wednesday	1	2	**222**	0	0	0	211	0	0	0	**211**	53.35	0		0	0	0	0	
2006	Aug	2	08/02/06	Wednesday	2	3	**214**	0	0	0	211	0	0	0	**211**	51.65	0		0	242	0	12481	
2006	Aug	2	08/02/06	Wednesday	3	4	**214**	0	0	0	211	0	0	0	**211**	51.18	0		0	242	0	12367	
2006	Aug	2	08/02/06	Wednesday	4	5	**214**	0	0	0	211	0	0	0	**211**	51.18	0		0	242	0	12367	
2006	Aug	2	08/02/06	Wednesday	5	6	**214**	0	0	0	211	0	0	0	**211**	53.79	0		0	0	0	0	
2006	Aug	2	08/02/06	Wednesday	6	7	**339**	110	0	0	215	0	0	0	**325**	65.11	87		0	0	0	0	
2006	Aug	2	08/02/06	Wednesday	7	8	**392**	160	0	0	215	0	0	0	**375**	66.82	61		75	0	4589	0	

Exhibit ICNU/106
Savings from Allocation of Reserves to Beaver - August 2006

2006	Aug	2	08/02/06	Wednesday	8	9	**462**	284	0	0	215	0	0	0	**499**	68.24	61	75	0	4589	0
2006	Aug	2	08/02/06	Wednesday	9	10	**492**	408	0	0	215	0	0	0	**622**	68.87	61	75	0	4589	0
2006	Aug	2	08/02/06	Wednesday	10	11	**541**	445	0	0	215	0	0	0	**659**	69.18	61	75	0	4589	0
2006	Aug	2	08/02/06	Wednesday	11	12	**550**	445	0	0	215	0	0	0	**659**	69.98	61	75	0	4589	0
2006	Aug	2	08/02/06	Wednesday	12	13	**557**	445	0	0	215	0	0	0	**659**	69.98	61	75	0	4589	0
2006	Aug	2	08/02/06	Wednesday	13	14	**564**	445	0	0	215	0	0	0	**659**	71.33	61	75	0	4589	0
2006	Aug	2	08/02/06	Wednesday	14	15	**583**	445	0	0	215	0	0	0	**659**	73.46	61	75	0	4589	0
2006	Aug	2	08/02/06	Wednesday	15	16	**591**	445	0	0	215	0	0	0	**659**	75.51	61	75	0	4589	0
2006	Aug	2	08/02/06	Wednesday	16	17	**598**	445	0	0	215	0	0	0	**659**	77.97	61	75	0	4589	0
2006	Aug	2	08/02/06	Wednesday	17	18	**590**	445	0	0	215	0	0	0	**659**	78.44	61	75	0	4589	0
2006	Aug	2	08/02/06	Wednesday	18	19	**566**	445	0	0	215	0	0	0	**659**	76.06	61	75	0	4589	0
2006	Aug	2	08/02/06	Wednesday	19	20	**523**	445	0	0	215	0	0	0	**659**	75.12	61	75	0	4589	0
2006	Aug	2	08/02/06	Wednesday	20	21	**525**	445	0	0	215	0	0	0	**659**	71.64	61	75	0	4589	0
2006	Aug	2	08/02/06	Wednesday	21	22	**490**	244	0	0	215	0	0	0	**458**	66.20	61	75	0	4589	0
2006	Aug	2	08/02/06	Wednesday	22	23	**470**	0	0	0	215	0	0	0	**215**	61.60	0	0	0	0	0
2006	Aug	2	08/02/06	Wednesday	23	24	**394**	0	0	0	211	0	0	0	**211**	56.87	0	0	0	0	0
2006	Aug	3	08/03/06	Thursday	0	1	**398**	0	0	0	211	0	0	0	**211**	54.49	0	0	0	0	0
2006	Aug	3	08/03/06	Thursday	1	2	**222**	0	0	0	211	0	0	0	**211**	53.35	0	0	0	0	0
2006	Aug	3	08/03/06	Thursday	2	3	**214**	0	0	0	211	0	0	0	**211**	51.65	0	0	242	0	12481
2006	Aug	3	08/03/06	Thursday	3	4	**214**	0	0	0	211	0	0	0	**211**	51.18	0	0	242	0	12367
2006	Aug	3	08/03/06	Thursday	4	5	**214**	0	0	0	211	0	0	0	**211**	51.18	0	0	242	0	12367
2006	Aug	3	08/03/06	Thursday	5	6	**214**	0	0	0	211	0	0	0	**211**	53.79	0	0	0	0	0
2006	Aug	3	08/03/06	Thursday	6	7	**347**	110	0	0	215	0	0	0	**325**	65.11	87	0	0	0	0
2006	Aug	3	08/03/06	Thursday	7	8	**427**	160	0	0	215	0	0	0	**375**	66.82	61	75	0	4589	0
2006	Aug	3	08/03/06	Thursday	8	9	**480**	284	0	0	215	0	0	0	**499**	68.24	61	75	0	4589	0
2006	Aug	3	08/03/06	Thursday	9	10	**494**	408	0	0	215	0	0	0	**622**	68.87	61	75	0	4589	0
2006	Aug	3	08/03/06	Thursday	10	11	**541**	445	0	0	215	0	0	0	**659**	69.18	61	75	0	4589	0
2006	Aug	3	08/03/06	Thursday	11	12	**554**	445	0	0	215	0	0	0	**659**	69.98	61	75	0	4589	0
2006	Aug	3	08/03/06	Thursday	12	13	**557**	445	0	0	215	0	0	0	**659**	69.98	61	75	0	4589	0
2006	Aug	3	08/03/06	Thursday	13	14	**563**	445	0	0	215	0	0	0	**659**	71.33	61	75	0	4589	0
2006	Aug	3	08/03/06	Thursday	14	15	**579**	445	0	0	215	0	0	0	**659**	73.46	61	75	0	4589	0
2006	Aug	3	08/03/06	Thursday	15	16	**592**	445	0	0	215	0	0	0	**659**	75.51	61	75	0	4589	0
2006	Aug	3	08/03/06	Thursday	16	17	**601**	445	0	0	215	0	0	0	**659**	77.97	61	75	0	4589	0
2006	Aug	3	08/03/06	Thursday	17	18	**588**	445	0	0	215	0	0	0	**659**	78.44	61	75	0	4589	0
2006	Aug	3	08/03/06	Thursday	18	19	**560**	445	0	0	215	0	0	0	**659**	76.06	61	75	0	4589	0
2006	Aug	3	08/03/06	Thursday	19	20	**522**	445	0	0	215	0	0	0	**659**	75.12	61	75	0	4589	0
2006	Aug	3	08/03/06	Thursday	20	21	**520**	445	0	0	215	0	0	0	**659**	71.64	61	75	0	4589	0
2006	Aug	3	08/03/06	Thursday	21	22	**481**	244	0	0	215	0	0	0	**458**	66.20	61	75	0	4589	0
2006	Aug	3	08/03/06	Thursday	22	23	**460**	0	0	0	215	0	0	0	**215**	61.60	0	0	0	0	0
2006	Aug	3	08/03/06	Thursday	23	24	**413**	0	0	0	211	0	0	0	**211**	56.87	0	0	0	0	0
2006	Aug	4	08/04/06	Friday	0	1	**426**	0	0	0	211	0	0	0	**211**	54.49	0	0	0	0	0
2006	Aug	4	08/04/06	Friday	1	2	**222**	0	0	0	211	0	0	0	**211**	53.35	0	0	0	0	0
2006	Aug	4	08/04/06	Friday	2	3	**214**	0	0	0	211	0	0	0	**211**	51.65	0	0	242	0	12481
2006	Aug	4	08/04/06	Friday	3	4	**214**	0	0	0	211	0	0	0	**211**	51.18	0	0	242	0	12367
2006	Aug	4	08/04/06	Friday	4	5	**214**	0	0	0	211	0	0	0	**211**	51.18	0	0	242	0	12367
2006	Aug	4	08/04/06	Friday	5	6	**214**	0	0	0	211	0	0	0	**211**	53.79	0	0	0	0	0
2006	Aug	4	08/04/06	Friday	6	7	**319**	110	0	0	215	0	0	0	**325**	65.11	87	0	0	0	0
2006	Aug	4	08/04/06	Friday	7	8	**429**	160	0	0	215	0	0	0	**375**	66.82	61	75	0	4589	0
2006	Aug	4	08/04/06	Friday	8	9	**453**	284	0	0	215	0	0	0	**499**	68.24	61	75	0	4589	0
2006	Aug	4	08/04/06	Friday	9	10	**512**	408	0	0	215	0	0	0	**622**	68.87	61	75	0	4589	0
2006	Aug	4	08/04/06	Friday	10	11	**542**	445	0	0	215	0	0	0	**659**	69.18	61	75	0	4589	0
2006	Aug	4	08/04/06	Friday	11	12	**555**	445	0	0	215	0	0	0	**659**	69.98	61	75	0	4589	0

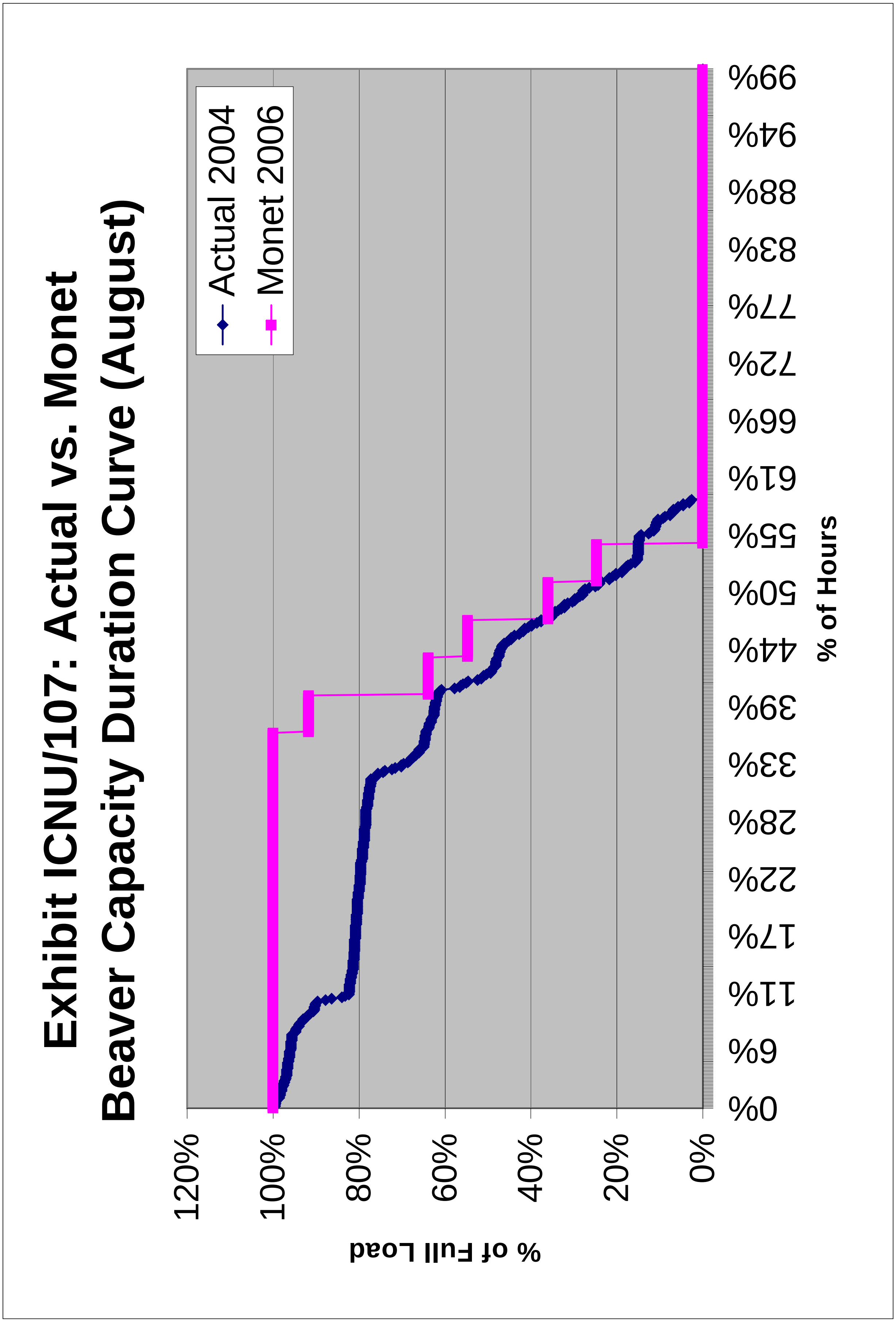
Exhibit ICNU/107: Actual vs. Monet
Beaver Capacity Duration Curve (August)
Actual 2004
Monet 2006
% of Full Load
120%
100%
80%
60%
40%
20%
0%
% of Hours
0%
6%
11%
17%
22%
28%
33%
39%
44%
50%
55%
61%
66%
72%
77%
83%
88%
94%
99%

June 17, 2005

TO: Vikie Bailey-Goggins
OPUC

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-172
PGE Response to Staff Data Request
Dated June 3, 2005
Question 004

Request:

At Tinker – Niman – Tooman/19 lines 11-13 the company indicates that a shut-down at the Sullivan plant included in the 2005 RVM was postponed and is now included in the 2006 RVM.

a. **Please indicate the timing and duration of the Sullivan shut-down included in the 2005 RVM.**

b. **Please quantify the replacement power costs associated with the Sullivan shut-down in the 2005 RVM.**

c. **Please indicate the timing and duration of the Sullivan shut-down included in the 2006 RVM.**

d. **Please quantify the replacement power costs associated with the Sullivan shut-down in the 2006 RVM.**

e. **Given that the Sullivan maintenance outage was included in the 2005 RVM and postponed, does including a similar outage in the 2006 RVM double-count the replacement power costs? If no, why not?**

Response:

a. The entire Sullivan plant is shut down for all days in July through October for construction of fish migration structure. This amounts to 123 days.

b. Replacement power cost is $2.128 million, based on running MONET with and without the shutdown.

	NVPC ($000)	
With shutdown	491,304	based on Nov. 15, 2004 Suppl. RVM Case
Without shutdown	489,176	
Difference	2,128	

c. The entire Sullivan plant is shut down from June 12 through October for construction of fish migration structure. This amounts to 142 days.

d. Replacement power cost is $2.725 million, based on running MONET with and without the shutdown.

	NVPC ($000)	
With shutdown	646,765	based on April 1, 2005 RVM filing
Without shutdown	644,040	
Difference	2,725	

e. No. The event is an element of ratemaking. PGE prepares its power cost forecasts with the most current and best information available at that time. However, plant maintenance outages seldom perfectly match the forecast. These deviations from the actual power cost forecast can have positive or negative effects on PGE's actual power costs. For example, plant outages may occur at a different time and may be shorter or longer than forecast. In addition, PGE may need to schedule a plant outage that is not in the forecast. PGE does not collect for outages that are unscheduled or last longer than forecasted.

Attachment 004-A is a comparison between the thermal plant maintenance outages forecasted in Monet and actuals from 2003 though May 2005. It demonstrates that forecasts seldom match the actual outages for maintenance. For example, in 2003 the actual outage for Boardman was one day shorter than forecasted (29 days instead of 30 days), while the outage at Beaver was 47 days longer (75 days instead of the forecasted 28 days). For 2005, we reported preliminary actuals through May, as available.

UE-172
Attachment 004-A
Forecasted vs. Actual Planned Outages since 2003

Attachment 004-A

		Planned Outages - Monet Forecast (days)					Actual Planned Outages (days)					
	Docket	Boardman	Colstrip 3	Colstrip 4	Coyote	Beaver	Boardman	Colstrip 3	Colstrip 4	Coyote	Beaver	
2003	UE-139	30	0	58	28	28	29	0	56	35	75	
2004	UE-149	69	44	0	0	17	72	49	0	4	38	
2005	UE-161	32	7	7	9	39	29	0	0	15	n.a.	Through May 2005