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Suite 2460
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June 30, 2004

Via Courier

Ms. Carol Hulse
Oregon Public Utility Commission
P.O. Box 2148
Salem OR 97308-2148

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY
Adjustments to Schedule 125 (2005 RVM Filing)
Docket No. UE 161

Dear Ms. Hulse:

Enclosed please find an original and six (6) copies of the Redacted Direct Testimony of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities in the above-captioned Docket.

Please return one file-stamped copy of the testimony in the self-addressed, stamped envelope provided. Thank you for your assistance.

Sincerely,

Ruth A. Miller

Ruth A. Miller

Enclosures
cc: Service List

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 161

In the Matter of Portland General Electric Company's Application for Annual Adjustment to Schedule 125 Under the Terms of the Resource Valuation Mechanism	))))))

2005 RESOURCE VALUATION MECHANISM POWER COSTS

REDACTED

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

June 30, 2004

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, 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 three Portland General Electric ("PGE" or the "Company") cases: UE 137 and UE 139 in 2002 and UE 149 in 2003. In those cases, I addressed PGE's Resource Valuation Mechanism ("RVM") and PGE's request for a power cost adjustment mechanism ("PCA"). I also filed testimony in two PacifiCorp rate proceedings in Oregon (UE 111 and UE 116). Both cases were ultimately settled, UE 111 in its entirety, and UE 116 on the issues I addressed in my testimony. In those cases, I addressed issues related to modeling of net power costs and a PCA. I also filed testimony in PacifiCorp Docket No. UM 995, quantifying the disallowances proposed by other ICNU witnesses and the costs of a hydro energy deficit experienced by that company.

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, Washington 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 2005. 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 11, 2004 variable power cost estimate of $499.3 million for 2005 is overstated. I recommend that PGE's power costs be reduced between $3.9 million and $7.2 million to re-price four imprudent contracts and reduced by an additional amount due to PGE's use of an overstated load forecast.[1/]

2. PGE includes the cost of four 2001 purchase contracts in its 2005 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 between $3.9 and $7.2 million.

3. PGE's load forecast optimistically assumes a strong recovery from Oregon's economic recession. There is substantial doubt concerning the validity of this assumption. PGE has a history of overstating its load forecast and the Company's forecast model cannot be properly reviewed in the context of a limited RVM proceeding. Further, the Company has an incentive to overstate the forecast. Consequently, I recommend use of the most recent twelve months of actual data as the load forecast for this proceeding. ICNU submitted a data request to PGE asking the Company to provide a MONET run utilizing actual load data for the load forecast. Such a model run would reflect the overall impact on power costs of using a load forecast based on actual data. PGE objected to that request and did not provide the run requested. ICNU has contacted PGE and submitted a subsequent request that the Company perform the model run, but the Company had not responded as of the time this testimony was finalized. ICNU will provide supplemental testimony regarding the impact of this issue on 2005 power costs when ICNU obtains the necessary information.

4. I am satisfied that PGE has met the requirements of the Settlement in UE 149 to develop adequate enhancements to the thermal and hydro dispatch

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[1/] These values are based on the most recent costs provided by PGE in the draft Monet run filed on June 11, 2004, in UE 161.

logic. As a result, I see no need for further changes to MONET for RVM 2006 and beyond. I recommend that the Commission "freeze" the model at this time, to further simplify the RVM process and prevent a new cycle of selective enhancements of the model.

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 government agencies
> - Market power prices (including transmission to the Company)
> - Transmission and ancillary services
> - Retail load forecast

Schedule 125, Sheet No. 125-4.

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

A. I participated in the technical conferences conducted in this proceeding. 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 2005. In addition, I have reviewed PGE's draft MONET run filed on June 11, 2004.

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 discovery responses.

2001 Purchase Contracts

Q. WHY DO YOU PROPOSE AN ADJUSTMENT TO RE-PRICE FOUR 2001 PURCHASE CONTRACTS?

A. The Company has included $38.1 million in the 2005 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 much higher than in more recent times. The cost of these contracts reflects the residual effects of the wholesale market problems that occurred from mid 2000 to June 2001.

Q. SHOULD THESE CONTRACTS BE INCLUDED IN THE 2005 RVM?

A. No. In the 2003 RVM case, Docket No. UE 139, the Commission made a substantial disallowance related to 2003 power contracts made in the first half of

2001. Re PGE, OPUC Docket No. UE 139, Order No. 02-772 at 14 (Oct. 30, 2002) ("Order No. 02-772"). The 2005 contracts were entered into at the same time and there should be a disallowance for the same reasons as 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 $14.65 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 12-18 months forward. Order No. 02-772 at 11-14. 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.
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> 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.
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> 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.
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> 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.
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> 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.

Id. (internal footnotes omitted).

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 begin 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 purchases of on-peak power delivered after February 2003 were imprudent, it is hard to see any justification for a flat power product to be delivered at a much later time.

Q. HOW SHOULD THE COMMISSION DEAL WITH THIS ISSUE?

A. The development of an imprudence adjustment is always a difficult undertaking. The Commission accepted the 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.[2/]

In the 2004 RVM case, Docket No. 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 at Galbraith/23 (July 2, 2003). He testified that market liquidity had declined since

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

the time of UE 139, and therefore, the 18-month forward curve could not be considered a good representation of market liquidity. Id. He further testified that it was not appropriate to re-price three-year contracts as though they were three one-year deals. Id. Had Mr. Galbraith supported the UE 139 methodology, the disallowance would have been $11.1 million. Id. at 22. Instead, Mr. Galbraith recommended use of a proxy price based on the lowest cost of the four contracts. Id. at 24. Based on this approach, he recommended a disallowance of $7.2 million. Id. Ultimately, the issue of the contracts was resolved as part of a comprehensive settlement of all issues in UE 149. Re PGE, OPUC Docket No. UE 149, Order No. 03-535 at Appendix A (Aug. 29, 2003) ("UE 149 Stipulation"). As a result, the UE 149 Stipulation provides no precedent for this case.

Q. WHAT WOULD BE THE IMPACT OF APPLICATION OF THE STAFF METHODOLOGY FROM UE 149 IN THIS CASE?

A. The methodology advocated by Staff in UE 149 is a reasonable approach. Had Staff advocated use of the Commission's UE 139 precedent in UE 149, Staff would have recommended a larger disallowance. As a result, if the case had been litigated, a larger disallowance likely would have resulted assuming the Commission followed its UE 139 precedent. However, over the life of these contracts, based on the forward curves in place in UE 149, the disallowance under the Staff UE 149 method and the UE 139 precedent would have produced roughly the same disallowance. Consequently, the Commission can view its UE 139 precedent as being effectively about the same as the Staff UE 149 method.

Confidential Exhibit ICNU/102 shows that application of Staff's approach in UE 149 to the contracts at issue in this proceeding produces a disallowance of approximately $7.2 million.

Q. WHAT WOULD THE UE 139 PRECEDENT IMPLY FOR THIS CASE?

A. In UE 139, the Commission re-priced the imprudent contracts according to the PGE trading curve for July 2001 included in the Company's July MONET run in UE 115. It is difficult to duplicate in this proceeding the disallowance adopted in UE 139, because PGE did not perform a July draft MONET run last year. PGE performed draft MONET runs on June 23, 2003, and September 2, 2003. Applying the Commission's UE 139 precedent using the PGE June 23, 2003 forward price curves results in a reduction to variable net power costs of $3.9 million in this case. However, there is a problem with applying the UE 139 precedent to this year's contracts that is similar to the one identified by Staff witness Maury Galbraith in UE 149. There is no evidence in this docket that the 18-month forward curve can be considered a good representation of market liquidity for purchases in 2005. <u>See</u> OPUC Docket No. UE 149, Staff/100 at Galbraith/23. That is the standard by which the Commission selected its proxy price in UE 139. Order No. 02-772 at 14. There also is a problem in that strict application of the UE 139 precedent in this case would allow PGE to mitigate the disallowance, because two of the contracts were priced below the June 23, 2003 forward curve. If this disallowance were adopted, it may allow PGE to benefit from imprudent decisions or it could result in the inclusion of imprudent costs in rates.

Q. WHAT OPTIONS DO YOU RECOMMEND FOR THE COMMISSION TO CONSIDER IF IT ONCE AGAIN FINDS PGE'S POWER PURCHASES TO BE IMPRUDENT?

A. The Commission has broad discretion in fashioning disallowances if it deems the contracts to be imprudent; however, there are some obvious options based on the results of the past RVM proceedings:

1. **Staff Methodology from UE 149:** The methodology advocated by Staff in UE 149 appears to present a reasonable result should the Commission find the contracts imprudent. Application of this methodology in this proceeding would result in approximately a $7.2 million reduction to power costs.

2. **UE 139 Precedent:** In UE 139, the Commission found the contracts to be imprudent and adopted a proxy price based on the 18-month forward price curve. Strict application of this precedent in this proceeding would result in a $3.9 million reduction to power costs.

3. **UE 139 Precedent Applied to Two Contracts:** As described above, strict application of the UE 139 Precedent may not be appropriate in this case. Under these circumstances, one option for the Commission to consider is ignoring the two lower-priced contracts in order to ensure that PGE did not benefit from decisions that were determined to be imprudent. If the Commission were to adopt this disallowance, it would result in a $5.5 million decrease in net variable power costs for 2005.

PGE Load Forecast Increase

Q. PGE WITNESSES NGUYEN, NIMAN, AND HAGER TESTIFY THAT OVER $30 MILLION OF THE REQUESTED INCREASE IN THIS CASE IS DUE TO INCREASES IN LOAD. WHAT IS THE CAUSE OF THIS LOAD INCREASE?

A. PGE indicates that this increase is the result of a more optimistic Oregon economic growth forecast developed by Global Insight "GI" (formerly Wharton Economic Forecasting Associates) and the State of Oregon Office of Economic Analysis ("OEA"). Re PGE, OPUC Docket No. UE 161, PGE/100 at Nguyen-Niman-Hager/7-8 (Apr. 1, 2004). Based on these forecasts, PGE predicts a 4.5%

increase in its cost of service load for 2005, which would represent an additional 800,000 MWh on the PGE system. Id. at Nguyen-Niman-Hager/19.

Q. HAVE YOU REVIEWED THE OEA FORECAST DOCUMENTS?

A. Yes. Exhibit ICNU/103 is a copy of the Executive Summary of the OEA forecast. It should be noted that the Executive Summary cites a number of problems and risk factors that threaten the assumed recovery. For example, OEA suggests that a "jobless recovery" in Oregon remains a problem. Further, OEA indicates that year over year job growth has not occurred since 2002:

> The fourth quarter initial estimate of job growth was a 1.7 percent annual rate over the third quarter. This is an improvement from the 0.9 percent decline in the third quarter. The past year has seen two positive and two negative quarters of job growth. *On an annual average basis, the year 2003 finished with job loss of 0.6 percent, the third consecutive year of job losses. On a year-over-year (Y/Y) basis, jobs declined in the fourth quarter by 0.5 percent. The last Y/Y growth was recorded in the fourth quarter of 2002. Y/Y growth should return by the second quarter of 2004*.
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> The Oregon economy experienced a jobless recovery through 2003. As the U.S. economy builds strength in 2004, Oregon should follow the same path. The jobless recovery will slowly become a job generating recovery with jobs regaining their pre-recession levels in early 2005. OEA forecasts employment to grow 1.6 percent in 2004 and 2.2 percent in 2005.

ICNU/103 at RJF/1 (emphasis added).

This is significant because it indicates that the most recent historical data (referenced above) shows a continued *decline* in employment. It will probably be too early to tell if job growth has actually occurred until sometime well after the second quarter of 2004. Thus, the strength of the assumed recovery will certainly be unknown and likely in doubt for some time to come.

Additional risk factors are cited by OEA, including the following:

> Geopolitical risks. Although the combat phase of the war is over, uncertainty still surrounds the transition in Iraq, tensions with North Korea, and code orange security alerts all weigh heavily on businesses and consumers. Disruptions on travel, oil supplies, and consumer confidence could be severe. Oregon will not receive many direct funds from an increase in defense spending. The drop in business activity could be deeper if this uncertainty persists or if the transition out of war goes badly for the U.S. There is also an upside risk that transition issues are settled quickly and the stimulus to recovery is stronger than forecast.
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> Rising regional energy prices. More businesses may slow production and lay off workers. Natural gas prices have risen the past few months adding to production costs. Oil prices are stubbornly staying around $30 per barrel. Electricity prices related to natural gas powered turbine engines could also go up. Rate hikes have been in place since October 1, 2001. Bonneville Power Administration may lower rates but the latest contracts negotiations have fallen apart.
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> The recovery for semiconductors, software, and communications could be much slower than anticipated. Continued outsourcing of manufacturing could slow growth in this region. Recent commitments to move research out of the country would be very harmful to Oregon's high technology sector.

Id. at RJF/2 (emphasis added). Certainly recent events suggest that these and other risk factors cited by OEA could now be materializing. In fact, recent oil prices appear worse than anticipated and the situation in Iraq is certainly discouraging. This proceeding is certainly another manifestation of rising electricity prices. Based on the most recent information available, it certainly appears that the outlook is unsettled, and that a more pessimistic outlook may now be justified.

Q. DOES PGE HAVE ANY INCENTIVE TO RELY ON AN OVERLY OPTIMISTIC FORECAST IN RVM CASES?

A. Yes. In a traditional rate case, there is a tension between increases in billing units and increases in power costs. Both are driven by an increase in the load forecast. However, a utility company that uses an overly optimistic forecast does so at its own peril. The reduction in average rate levels (due to spreading all fixed costs over more billing units) may completely offset any variable power cost increases resulting from the higher forecast.

In an RVM proceeding, however, the focus is more exclusively on power costs and many kinds of fixed costs are not part of the analysis. Thus, there is more incentive to rely on an optimistic forecast. As noted above, in this case, PGE has attributed $30 million of the increase in 2005 net variable power costs to a load forecast that assumes 4.5% growth in cost of service load based on substantial economic recovery. OPUC Docket No. UE 161, PGE/100 at Nguyen-Niman-Hager/18-20.

Q. IF THE COMMISSION ADOPTS PGE'S OPTIMISTIC LOAD FORECAST FOR 2005 BUT THE PROJECTED LOAD GROWTH DOES NOT OCCUR, WHAT WILL BE THE RESULT UNDER THE RVM PROCESS?

A. PGE likely will over-recover its actual net variable power costs in 2005.

Q. DOES PGE HAVE A TRACK RECORD OF PRODUCING OVERLY OPTIMISTIC FORECASTS?

A. Yes. On June 11, 2002, PGE presented a workshop where the Company acknowledged that it had overstated its UE 115 load forecast. Exhibit ICNU/104 is a copy of the presentation from that workshop.

In UM 1039, the docket in which the Commission reviewed the prudence of the costs recorded under PGE's 15-month PCA approved in UE 115, the Company acknowledged that overstatement of the load forecast was the leading component in the PCA balance. In fact, the Company indicated the load forecast error (7.3%) was responsible for more than $70 million of the approximately $80 million PCA balance. Re PGE, OPUC Docket No. UM 1039, PGE/200 at Niman-Hager-Tooman/6; PGE/201 at 7 (Jan. 30, 2004). Because the sharing mechanism reduced the final PCA variance to substantially less than this amount, it appears that without the load forecast error, there would have been no PCA balance to recover.

The subsequent forecast for the 2003 RVM was also overstated, according to information provided by the Company in discovery in this docket. Re PGE, OPUC Docket No. UE 161, PGE Response to ICNU Data Request No. 3.3 (Jun. 7, 2004). While the overall error for 2003 was not as substantial as in the past, it reflects the pattern of overstated load forecasts. Consequently, there appears to have been an overstatement in each of the PGE load forecasts relied upon for setting rates since UE 115.

Q. HAS THERE BEEN ANY EXPLANATION PROVIDED BY PGE AS TO THE REASONS FOR THESE LOAD FORECAST ERRORS?

A. Yes. This issue was explored at the June 11, 2002 workshop. At that time, PGE made a detailed presentation concerning its load forecast and the problems that lead the Company to substantially overstate its load forecast in UE 115, as compared to the then current May 2002 PCA forecast. As we now know, even the reduced PCA forecast of May 2002 that PGE relied upon in this meeting turned out to be substantially overstated. There are several key problems that seem to be endemic to the PGE forecast:

- PGE initially underestimated the depth of the economic turndown;
- PGE consistently assumed an early recovery from the recession induced downward trend in load that has not yet materialized;
- Price induced effects were stronger than assumed;
- The model was based on sample periods when prices were declining, and failed to capture the effects of changing relationships;
- Forecasts of employment were too optimistic; and
- The Company failed to anticipate changes in plans of large customers.

ICNU/104 at RJF/7, RJF/11, RJF/12, RJF/15.

Q. DID PGE IDENTIFY THE AMOUNT BY WHICH ITS MODEL OVERSTATED PRIOR FORECASTS?

A. Yes. The Company identified structural problems in the model that were responsible for an overstatement of 87 MW between the UE 115 and May 2002 PCA forecast. Id. at 15. At the same time, the Company believed that economic drivers were responsible for 33 MW of the error and failure to anticipate the plans of large customers was responsible for 60 MW. Id.

Q. DO MANY OF THESE SAME PROBLEMS REMAIN TODAY?

A. I believe so. First, PGE continues to rely on an economic forecast that assumes the recovery is "just around the corner." Second, to address the structural problems, it appears the Company has merely added more data points and re-estimated the model. Finally, the Company has not demonstrated that it has corrected the concerns about taking into account the plans of its largest customers.

Q. WHAT IS YOUR CONCLUSION BASED ON THIS ACCUMULATION OF EVIDENCE CONCERNING THE PGE LOAD FORECAST?

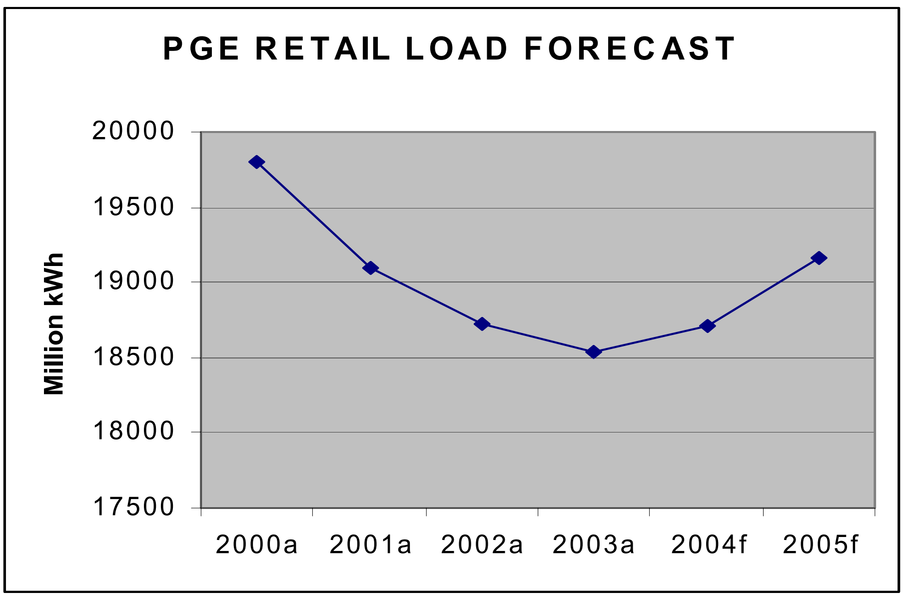
A. The Company's forecast has been overstated since UE 115 based on the structural problems in the model identified by PGE and the Company's reliance on overly optimistic economic forecasts. The Company forecast first failed to accurately assess the depths of the economic recession and now assumes a level of recovery that has not yet materialized. There are structural problems with the model and the Company has failed to anticipate the changes in plans of large customers.

Q. MOVING TO THE PRESENT DAY, HOW DOES THIS ALL APPLY TO THE CURRENT PGE FORECAST?

A. PGE continues to assume a recovery from the economic recession and continues to apply its forecast model. Given the incentive the Company has to be optimistic, I recommend the Commission consider whether continued reliance on the PGE forecast for the 2005 RVM continues to be the wisest course of action, especially given that the forecast increase in load represents over $30 million of the power cost increase requested by PGE in this proceeding.

Q. HOW OPTIMISTIC IS THE NEW PGE FORECAST?

A. In PGE/100, page 6, Table 1, there is a comparison of recent actual retail load with the current forecast. OPUC Docket No. UE 161, PGE/100 at Nguyen-Niman-Hager/6. The figure below shows this data. The figure shows that PGE's actual loads declined every year from 2000 to 2003. The Company now forecasts a reversal of this decline, and that in 2005, sales will recover to levels higher than any year since 2000. Thus, the PGE model is predicting nearly a complete recovery in load in the next 18 months.



Q. IS PGE CONFIDENT OF THIS FORECAST?

A. PGE acknowledges that there is uncertainty surrounding many factors, which could cause the forecast to be unrealistic. OPUC Docket No. UE 161, PGE/100 at Nguyen-Niman-Hager/9. As a result of this uncertainty, PGE proposed to update its load forecast as conditions change.

Q. ARE THERE ANY OTHER ISSUES THAT MAKE IT PARTICULARLY DIFFICULT TO DEVELOP A REALISTIC LOAD FORECAST AT THIS TIME?

A. Certainly. One of the biggest challenges for any forecast is to anticipate "turning points." While the economic recovery in Oregon may be taking place, it is simply too early for there to be compelling evidence that it is finally occurring or at the rate that is assumed in PGE's load forecast for 2005. At this time, it is difficult to say whether the recovery is proceeding, stalled, or further decline is occurring. As was pointed out above, OEA indicates that Y/Y employment growth is not expected to take place until the second quarter of 2004, and it appears that the most recent historical data (Fourth Quarter 2003) showed continued decline. It is frequently the case that it takes many months before there is sufficient data to determine whether a recession has ended and recovery begun.

Q. DOES PGE'S PROPOSAL TO UPDATE THE LOAD FORECAST LATER IN THE YEAR RESOLVE THIS DILEMMA?

A. No. More information will become available later in the year; however, there are practical problems with this proposal. Under the current schedule for RVM updates, there is insufficient time for a thorough review of even the initial PGE load forecast model. There are nearly 500 pages of load forecast model workpapers. An update of the forecast at a later time would likely entail an equal number of pages. A complete analysis of the forecast and any subsequent updates would also involve a detailed study of all of the equations and statistical data relied upon by the Company. A complete re-specification and re-estimation of the model might be needed to provide a more realistic forecast. Finally, even if the workpapers for the PGE model are available, the OEA and GI forecasts remain little more than a "black box." In my view, there is no practical way in which the load forecast and subsequent updates can be reviewed within the context of the RVM filings.

Q. WHAT THEN IS YOUR PROPOSED SOLUTION TO THIS PROBLEM?

A. The Commission should consider an alternative approach in this proceeding to ensure that power costs are not based on a load forecast that may be overly optimistic in terms of the level of economic recovery. Under this alternative, the RVM model for 2005 would employ the most recent weather normalized actual loads instead of a load forecast. This would provide a much simpler RVM docket and would allow reasonable verification of the load assumptions. This approach would further simplify the RVM process, mitigate the risk of relying on an unverifiable load forecast, and eliminate any incentive PGE has to overstate the forecast.

Q. SCHEDULE 125, QUOTED ABOVE, ALLOWS PGE THE OPPORTUNITY TO UPDATE ITS RETAIL LOAD FORECAST IN THE RVM PROCEEDING. DOES YOUR PROPOSAL REQUIRE THE COMMISSION TO CHANGE THE TERMS OF THIS RATE SCHEDULE?

A. No. The most recent actual data would become the retail load forecast. In many situations, particularly when there is a substantial amount of uncertainty, the best forecast of the future value of a variable is its current value. There is no reason the Commission cannot consider the most recent actual load levels as the best current forecast of the short-term trend in load, especially given the difficulty associated with predicting the timing and pace of any economic recovery. Since the RVM establishes net variable power costs less than a year in advance of the rate effective period, there is not a substantial lag. In fact, the load data could be updated as late as the 4th quarter of the year. Unlike a general rate case, the rates determined in this proceeding will only be in effect for 2005. It may not be sufficient to rely on recent actual data as a long-term forecast for base rates that could be in effect for a number of years. However, for such a close in time application, reliance on actual data instead of the PGE forecast is reasonable. Given PGE's recent track record, there is little reason to have much confidence that the PGE forecast model will do any better than the most recent actual data.

Q. HAVE YOU QUANTIFIED THE IMPACT OF THIS PROPOSAL ON THE 2005 RVM ?

A. Not at this time. On June 14, 2004, ICNU sent data request ("DR") 4.2 to PGE, asking the Company to "[p]lease provide a MONET run with the most recent 12 months of actual load data replacing the assumed load forecast." ICNU/105 at RJF/1. The MONET run requested would demonstrate the impact on power costs of using the most recent twelve months of actual load data for the load forecast rather than the aggressive forecast used by PGE. PGE responded to DR 4.2 as follows:

> PGE objects to this request on the basis that it is vague and unduly burdensome. To incorporate 12 months of actual load data requires several assumptions. First, PGE forecasts loads on the basis of normal weather. It is unclear from the request if ICNU refers to actual loads on an actual or normal weather basis. Second, it is also unclear from the request if ICNU is referring to Cost of Service Loads or Total System Loads. Finally, ICNU has run Monet in previous dockets and has the ability to do so in this docket. PGE sent ICNU a copy of the Monet model as filed on April 1, 2004 and PGE's actual loads over the last 12 months were provided in PGE's response to ICNU Data Request No. 019. Thus, ICNU could perform the requested study.

Id. This answer is not completely accurate. First, I am reluctant to substitute my judgement for PGE's in terms of preparing some of the load modeling inputs to MONET. I believe that revising the load inputs would also involve re-running the load-shaping model, to which I do not have access. Also, I currently am unable to perform MONET runs because Monet requires Windows 98, while my computers use Windows XP. In previous dockets, I have been able to use other computers to run MONET but was unable to do so in this proceeding. I have spoken with PGE personnel in the past about this issue and we have attempted to solve the problem, but have been unable to do so. Finally, PGE did not contact ICNU to clarify any aspect of the request that the Company considered unclear.

I understand that counsel for ICNU has contacted PGE's counsel and asked once again that PGE provide the model run requested. However, PGE had not responded to this request as of the time that this testimony was due. Once this issue has been resolved, I will file supplemental testimony detailing the impact of this proposal.

MONET Updates

Q. SUMMARIZE THE REQUIREMENTS OF THE STIPULATION IN DOCKET NO. UE 149 REGARDING MONET UPDATES.

A. In UE 149, PGE proposed a substantial number of changes to the MONET model logic. ICNU and other parties objected to a number of these changes. In particular, ICNU argued that the Company had made selective changes in the model, focusing on alterations that increased costs, while ignoring those that reduced cost. Re PGE, OPUC Docket No. UE 149, ICNU/100 at 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. ICNU suggested that the Commission allow no additional changes to the MONET model. Id. at RJF/13. ICNU suggested in the alternative that if PGE's proposed changes to improve MONET were allowed, the hydro dispatch logic in MONET had to be improved to better match market prices, and PGE's proposed change to the Beaver plant dispatch logic should be modified. Id. at RJF/21, 31.

To resolve this issue, the parties agreed that PGE would not make further changes to MONET in 2005 or 2006, with the exception of limited changes to MONET related to hydro modeling and the Beaver and Coyote dispatch. UE 149 Stipulation at 3-4. The Stipulation required PGE to conduct workshops to develop new logic related to these subject areas and to work with the parties to develop mutually agreeable logic changes. Id. at 3. In the event the parties agreed to the new logic, there was a broad prohibition against additional logic changes in 2005 and 2006 outside of a new general rate case or unless agreed to by all parties. Id. at 3-4.

Q. DO YOU AGREE WITH THE NEW LOGIC PROPOSED BY PGE?

A. Based on my review of the workpapers and information provided in the workshops, I am satisfied that PGE has reasonably implemented the UE 149 Stipulation with respect to hydro modeling and Beaver and Coyote dispatch. I have tested the new logic for reasonableness and have not found any errors or shortcomings in this implementation. While there is always the possibility of an undiagnosed logic error, I am in agreement with the proposed logic.

Q. I ASSUME THAT PGE ALSO MUST AGREE WITH THIS NEW LOGIC. WHAT DOES THIS IMPLY AS REGARDS FUTURE ENHANCEMENTS TO MONET?

A. Parties that disagree with the logic changes proposed by PGE have the opportunity in this case to propose alternatives. Based on discussions with CUB and Staff, I don't anticipate any such proposals. In my view, this implies no further changes can be made to the MONET logic in the 2006 RVM. According to the UE 149 Stipulation, no logic changes other than those related to hydro and the Beaver/Coyote logic may be proposed outside of a new rate case.

Q. DOES THE STIPULATION ALLOW PGE TO MAKE ADDITIONAL CHANGES TO THE HYDRO AND BEAVER/COYOTE LOGIC IN THE REBUTTAL PHASE OF THIS CASE OR THE 2006 RVM?

A. I don't believe it does. PGE was required to make a good faith effort to complete the logic change by December 31, 2003. UE 149 Stipulation at 3. While PGE may have missed this deadline by a few months, I believe the Company and all parties did make a good faith effort. From my perspective this means (barring unexpected criticism of the new logic by CUB or Staff) the requirements of the Stipulation have been met, and no additional changes should be allowed. To suggest that additional months or even a year are required to complete the enhancements would run afoul of the requirement to finish this process by the end of 2003. Further, it would be impossible for parties to respond to any new logic adjustments made by PGE in the rebuttal phase of this case. Therefore, the Commission should not entertain any more changes to the model in this case.

Q. WHAT THEN IS YOUR RECOMMENDATION TO THE COMMISSION?

A. I recommend the Commission find that PGE and the parties have met the requirements of the Stipulation in Docket No. UE 149. Consequently, the MONET logic should be frozen, absent additional changes agreeable to all parties.

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

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	Pennsylvania Power Committee	Phase-in of nuclear unit. Power & Light Co.
2/85 cancellation of	I-840381	PA	Phila. Area Ind. Energy Users' Group	Electric Co.	Philadelphia Economics of nuclear generating units.
3/85 fossil	Case No. 9243	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Economics of cancelling generating units.
3/85 storage	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped 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 Public Service Commission Staff	Georgia Power Co.	Cancellation of nuclear plant.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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.
10/88 gas	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of sales and revenues.

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Date	Case	Jurisdict.	Party	Utility	Subject
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 Businesses Advocating Tariff Equity (ABATE)	Consumers Power	DSM Policy Issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
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.

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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 Power Users Group	Tampa Electric Co.	Polk County Power Plant Rate Treatment Issues.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
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
10/00	22350	TX	OPC	TXU Electric	Stranded cost
10/00	99-263-U	AR	Tyson Foods	SW Elec. Coop	Cost of Service

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Date	Case	Jurisdict.	Party	Utility	Subject
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
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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.

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PROTECTIVE ORDER IN
OPUC DOCKET NO. UE-161

ICNU/102
RJF/1

EXECUTIVE SUMMARY

March 2004

Oregon Economic Forecast

The fourth quarter initial estimate of job growth was a 1.7 percent annual rate over the third quarter. This is an improvement from the 0.9 percent decline in the third quarter. The past year has seen two positive and two negative quarters of job growth. On an annual average basis, the year 2003 finished with job loss of 0.6 percent, the third consecutive year of job losses. On a year-over-year (Y/Y) basis, jobs declined in the fourth quarter by 0.5 percent. The last Y/Y growth was recorded in the fourth quarter of 2002. Y/Y growth should return by the second quarter of 2004.

The Oregon economy experienced a jobless recovery through 2003. As the U.S. economy builds strength in 2004, Oregon should follow the same path. The jobless recovery will slowly become a job generating recovery with jobs regaining their pre-recession levels in early 2005. OEA forecasts employment to grow 1.6 percent in 2004 and 2.2 percent in 2005.

Manufacturing will improve in 2004 with an annual increase of 2.1 percent. The sector will continue to grow in 2005 with an increase of 1.1 percent. Job growth is expected to level out in the outer years with 1.0 percent growth in 2006, then a slight declining trend in the outer years.

Wood products had a great finish to 2003 and should fare well in 2004 with a growth rate of 1.7 percent. This will not turn back the secular decline this industry has faced since the early 1980s.

Computer and electronic products, which contains semiconductors, should increase 1.4 percent in 2004, 2.7 percent in 2005, and 2.4 percent in 2006. Beyond this time, the national forecast calls for declines in this industry and Oregon's more mature high tech sector may follow suit.

Construction will turn the corner and add jobs into 2004. While single family residential construction may slow a little, the slack will be more than made up through the office and industrial markets coming into 2005 and 2006. Job gains will be 2.0 percent in 2004, 4.0 percent in 2005, and 2.8 percent in 2006.

Population growth is expected to be slightly higher than the U.S. average, but slower than the growth experienced in the mid-1990s. Slower growth will prevail over the next three years, with increases of 1.1 percent in 2004 through 2006.

Forecast Risks

Most economists believe that the economic recovery is in place. The only missing element is the job market. Industrial production has picked up and is efficiently handling the increase without more workers. But GDP turned in a whooping 8.2 percent increase in the third quarter of 2003 followed by a healthy 4.0 percent growth in the fourth quarter. Will this increased growth be enough to create more jobs? Oregon will be pulled along with a stronger U.S. economy, but Oregon's slower growth may provide very little relief to the unemployment situation in the state.

The major risks now facing the Oregon economy are:

- Geopolitical risks. Although the combat phase of the war is over, uncertainty still surrounds the transition in Iraq, tensions with North Korea, and code orange security alerts all weigh heavily on businesses and consumers. Disruptions on travel, oil supplies, and consumer confidence could be severe. Oregon will not receive many direct funds from an increase in defense spending. The drop in business activity could be deeper if this uncertainty persists or if the transition out of war goes badly for the U.S. There is also an upside risk that transition issues are settled quickly and the stimulus to recovery is stronger than forecast.

- Falling U.S. Dollar. As the dollar depreciates against other foreign currencies, U.S. exports are promoted. Oregon's manufacturing sector has a large dependency on international markets. If the U.S. dollar falls too quickly, this could harm Oregon's trading partners, weakening their economies and lowering their demand for Oregon products. A controlled lowering of the U.S. dollar is most beneficial to the Oregon economy.

- A further sharp and major stock market correction. This would further slow already dampened consumer spending. Lower stock prices could also limit the ability of businesses to raise necessary capital in the equity markets.

- A possible collapse of the housing market. The extremely low interest rates have caused a boom in home refinancing. As this activity matures and interest rates begin to rise, the added boost to consumer spending may also slow. Any drop in home price appreciations coupled with a large drop in mortgage refinancing could slow down consumer spending. Continued gains in personal income will be needed to keep consumer spending from falling.

- Rising regional energy prices. More businesses may slow production and lay off workers. Natural gas prices have risen the past few months adding to production costs. Oil prices are stubbornly staying around $30 per barrel. Electricity prices related to natural gas powered turbine engines could also go up. Rate hikes have been in place since October 1, 2001. Bonneville Power Administration may lower rates but the latest contracts negotiations have fallen apart.

- Budget shortfalls at state and local governments. The federal stimulus packages in the works could be countered by the fiscal drag from state and local governments. Estimates place the shortfalls for state governments at around $78 billion for fiscal year 2003. Oregon has seen a deeper drop in its revenues compared to most states. To the extent that spending cutbacks hit education and public infrastructure, the state could suffer longer-term impacts.

- The recovery for semiconductors, software, and communications could be much slower than anticipated. Continued outsourcing of manufacturing could slow growth in this region. Recent commitments to move research out of the country would be very harmful to Oregon's high technology sector.

- With the discovery of mad cow disease at a Washington dairy, the beef industry in the state could see some difficult times. Unknown is the impact of the bird flu which is sweeping Asia. This segment of the agricultural sector is facing serious challenges during what should be a good recovery period.

Demographic Forecast

The Census 2000 enumerated 3,421,399 persons in Oregon on April 1, 2000. This is an increase of 579,000 persons or 20.4 percent from the 1990 Census. Oregon ranked as the eleventh highest in the nation based on the rate of growth between the two censuses. In recent years, however, the population growth rate has slowed due to the struggling economy. Oregon's July 1, 2003 estimated population was 3.542 million, an increase of 1.05 percent over the 2002 population. The state's population is expected to reach 3.894 million in the year 2011, with an annual rate of growth ranging from 1.0 to 1.3 percent.

During the 2003-2011 period, the fastest growth in the age groups will show the effects of the baby-boom generation and continued positive, although weak, net migration of working age population and elderly retirees. Age groups 45-64 and 65 and over will have very high growth rates due to the continued entry of baby-boomers in 45-54 age group and increasingly larger cohorts reaching the retirement age. Young adult population in age group 18-24 will grow at slower than state total population growth rate. This will ease the pressure on public spending on college education. Children under the age of 5 will grow moderately while the K-12 population in the 5-17 age group will show a very slow growth. The population 25-44 age group will start to increase after several years of decline due to exiting baby-boom cohort. This age group will see a positive growth starting in the year 2003. Also, after a period of slow growth, elderly population growth rate will exceed the State's overall growth rate.

Revenue Forecast

On February 3, 2004, Oregon voters rejected temporary and permanent tax law changes originally passed by the 2003 Legislative Assembly and signed by Governor Kulongoski as House Bill 2152. The total impact on the 2003-05 General Fund revenue forecast is $777.9 million. Along with tax law changes, House Bill 2152 included $544.6 million in automatic disappropriations in the event that the changes were overturned. The net impact – reduced revenues less the reduction in expenditures – is a shortfall of $235.4 million directly attributable to the result of the Measure 30 vote.

The forecast for General Fund revenues received during the 2003-05 biennium is $10,084.2 million, a $44.3 million increase from December after adjusting for Measure 30's defeat. Agencies had until December 31, 2003 to expend 2001-03 appropriations. Unspent funds, known as reversions, totaled $76.0 million and raise the beginning balance for the current biennium to $133.1 million. Total projected resources available in 2003-05 equal $10,217.4 million. The projected ending balance for the current biennium is $20.7 million.

The forecast for General Fund revenues for the 2005-07 biennium is $11,240.4 million. This constitutes a drop of $617.5 million from the December forecast, with approximately $353.0 attributable to the defeat of Measure 30. For the 2007-09 biennium, General Fund revenues increase 11.9 percent to $12,575.4 million. The latest forecast is $648.9 million below the prior forecast.

Projected Lottery earnings for the current biennium equal $711.4 million, a $10.5 million increase over the December 2003 forecast. Total available resources, which include beginning balance and interest earnings on the Economic Development Fund, increased $4.6 million to $722.8 million. Table B.9 in Appendix B presents a detailed statement of 2003-05 Lottery resources and distributions.

Several revisions in the long-term assumptions, including average jackpot levels for Powerball resulting from a recent game change, increase sales forecast for future biennia. In 2005-07, earnings on Lottery sales will equal $728.3 million while available resources increase to $730.2 million. Earnings and available resources total $$767.6 million and $770.1 million, respectively, for the 2007-09 biennium.

Portland General Electric

RVM Workshop

PGE Retail Load Forecast & Recent Trends

June 11, 2002

Portland General Electric

Summary

- The economic recession hit Oregon early (October 2000) and particularly hard, worse than the '90s recession and nearly severe as the early-80's recessions
- The recession and customer response to the West Coast energy crisis and higher energy prices (elasticity) clearly affected demand for electricity
  - PGE retail load fell by almost 90 MWa (50 MWa adjusting for demand buybacks), or -3.6% in 2001 for the first time since the early 80's
  - And trailed authorized UE-115 forecast by 70 MWa (35 MWa adjusting for demand buybacks) in 2001
- Retail loads continue to lag, currently running at 3.6% below forecasts (PCA), in excess of 8% (roughly 200 MWa) below authorized UE-115 forecast and 5% below 2001 levels through April '02
- While the recession appears to have bottomed out in the U.S., the decline in economic activities in Oregon was so sharp that it may take longer to repair the damage
- Changing economic and electricity market environments necessitate retail load forecast model be regularly updated going forward

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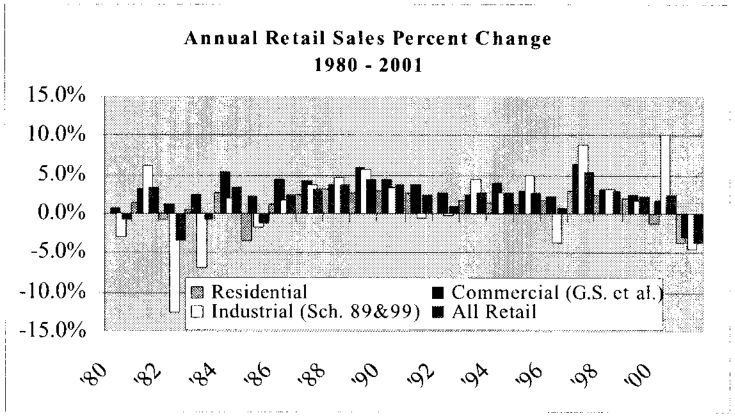
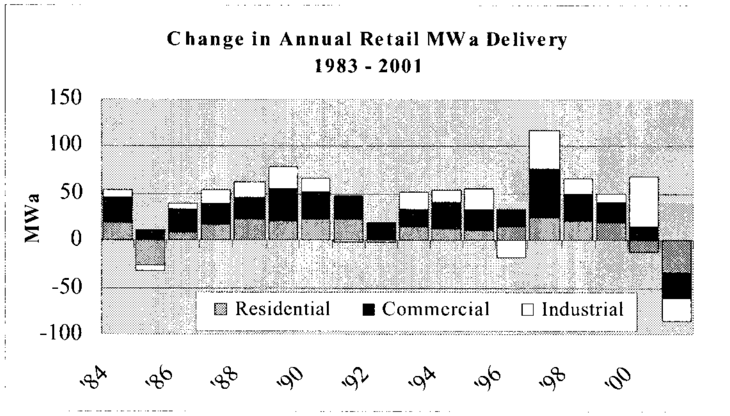
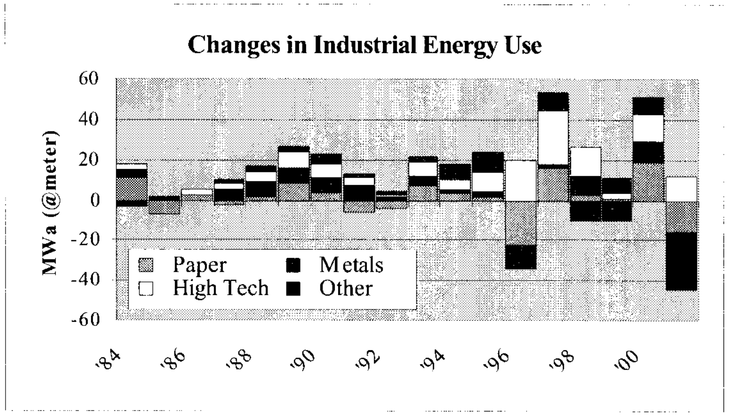
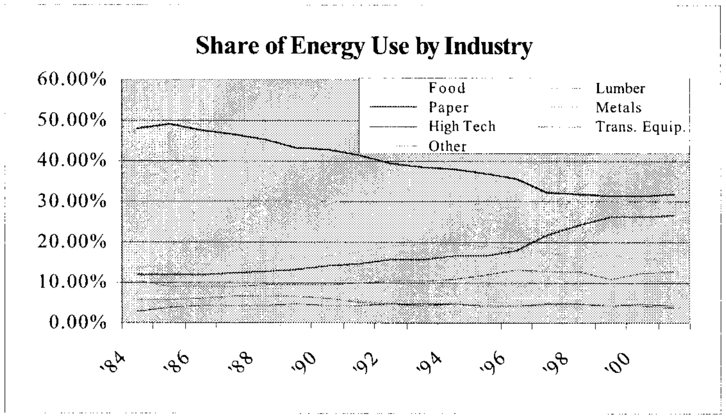
Historical PGE Retail Load Trends









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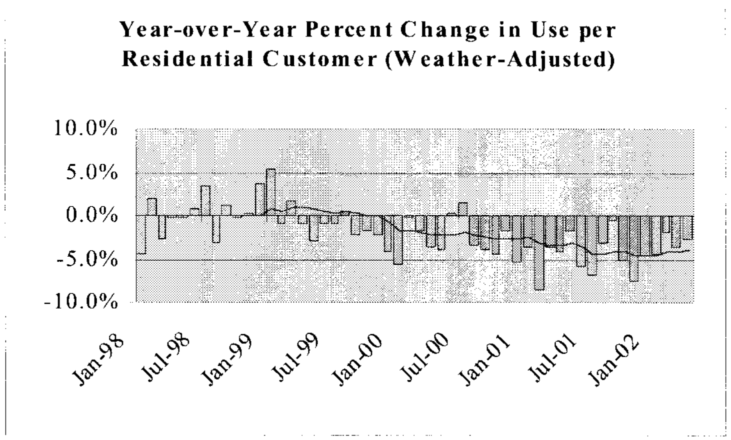
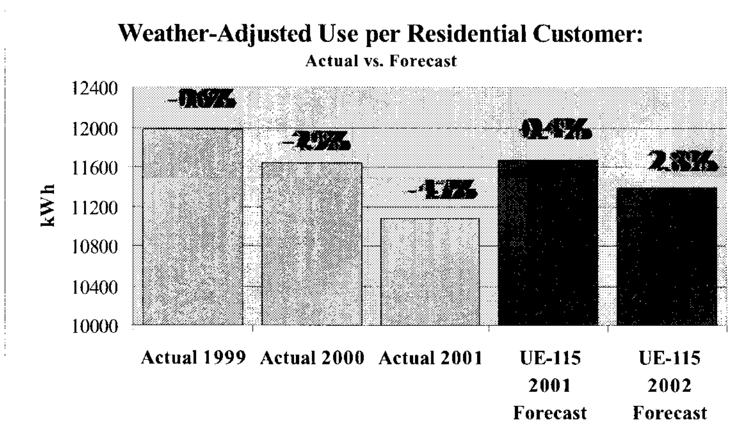
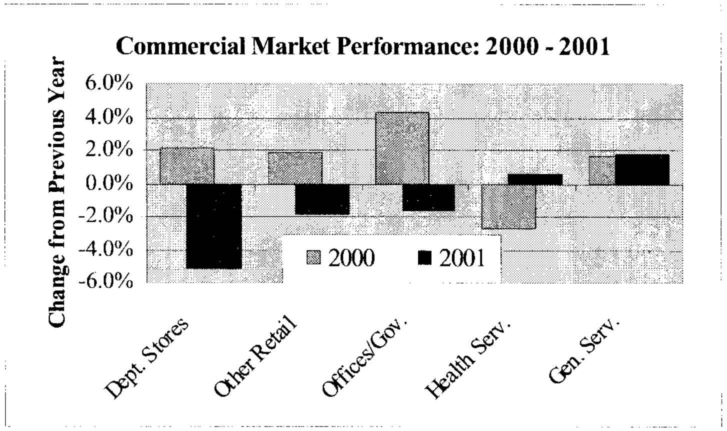
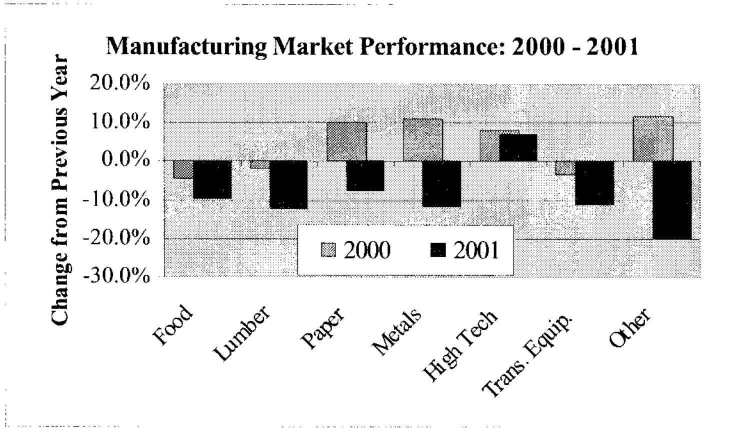
PGE Retail Market in 2001









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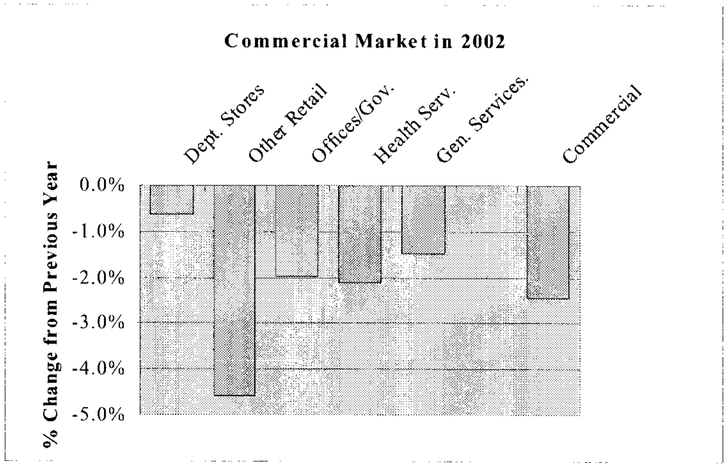
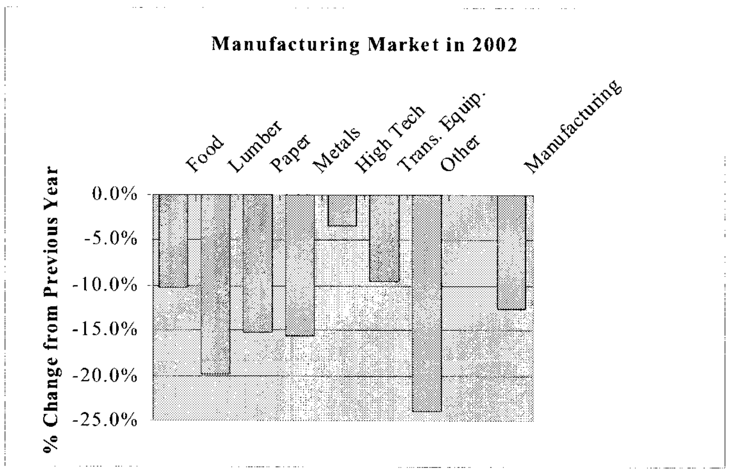
And 2002 to Date

- Retail loads (weather-adjusted) continue to lag through April 2002 across all sectors and industries, including high tech (closure by Fujitsu), declining by 5% from the previous year's levels. Deliveries fell
  - 1.8% in the Residential sector
  - 2.4% in the Commercial sector
  - 12.7% in the Manufacturing sector





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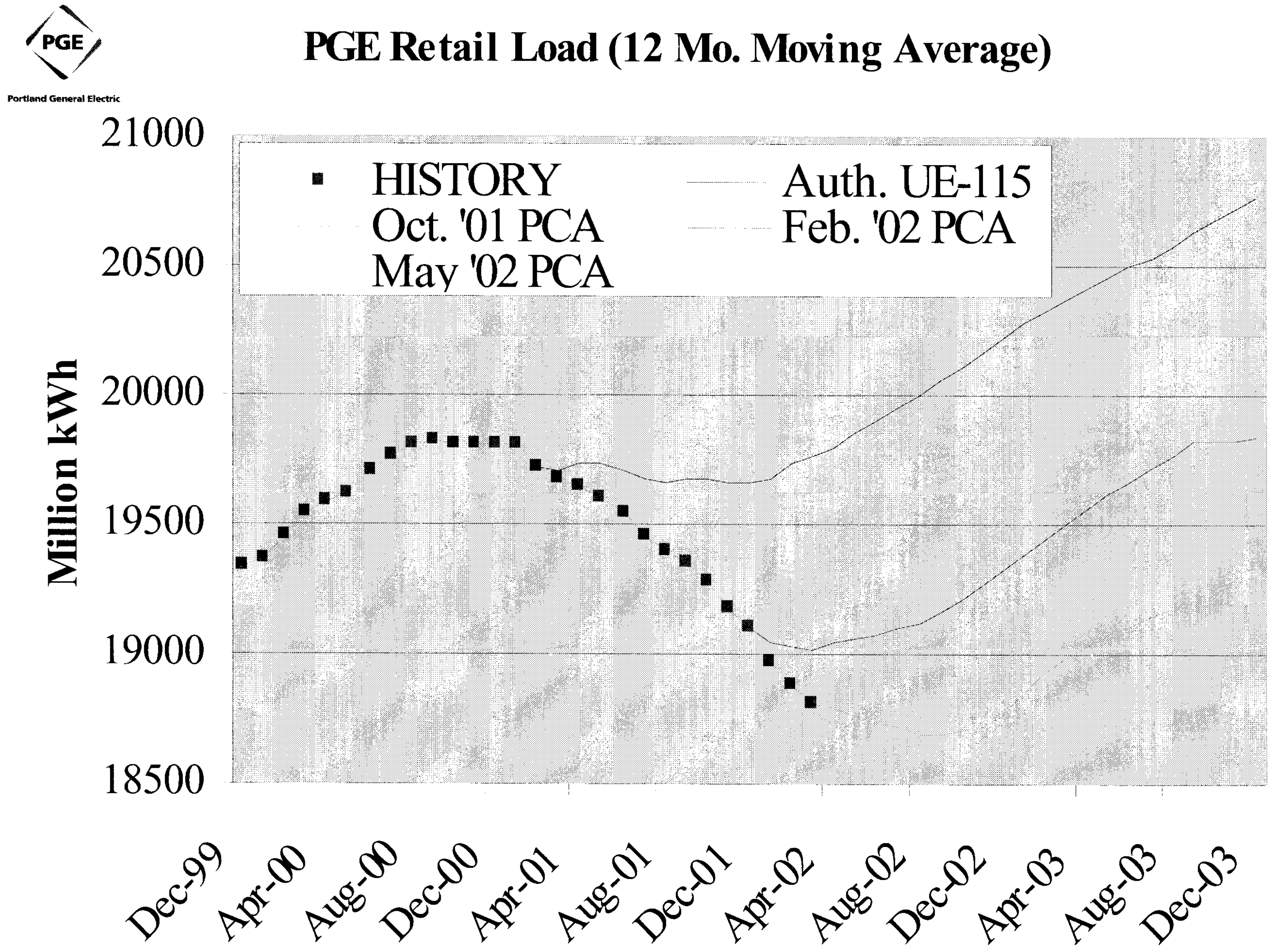
Retail Load Forecasts

(in million kWh)

	Weather-adjusted Actual	UE-115	Nov '01 PCA	Feb '02 PCA	May '02 PCA
2000	*19,806*				
2001	*19,097*	*19,658*			
2002		*20,227*	*19,503*	*19,324*	*18,763*
2003		*20,771*	*19,850*	*19,833*	*19,189*

PGE Retail Load (12 Mo. Moving Average)



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UE-115 Load Forecast Revisited

- The forecast (Authorized UE-115) called for retail load to decline 0.7% in 2001 (-0.3% after adjusting for CRPUD & CPUD) as economic growth was expected to stall and energy use per household to fall, but to rise by 2.9% in 2002 as the economy recovers, on par with most-recent 5-year 2.7% average
- The forecast did not take into account demand buyback except for Atofina, which shut down permanently in April 2001, but included 25 MWa price effect

	Million kWh			% Change		
	2000	2001	2002	'99 – '00	'00 – '01	'01 – '02
Residential	7,398	7,370	7,450	(1.3%)	(0.4%)	1.1%
Commercial	6,473	6,539	6,617	2.4%	1.0%	1.2%
Industrial	5,735	5,538	5,947	8.0%	(3.4%)	7.4%
Miscellaneous	199	212	214	(3.7%)	6.4%	0.8%
Total Retail	19,806	19,658	20,227	2.4%	(0.7%)	2.9%
(Adj. For CRPUD&CPUD)	19,719	19,658	20,227	2.7%	(0.3%)	2.9%

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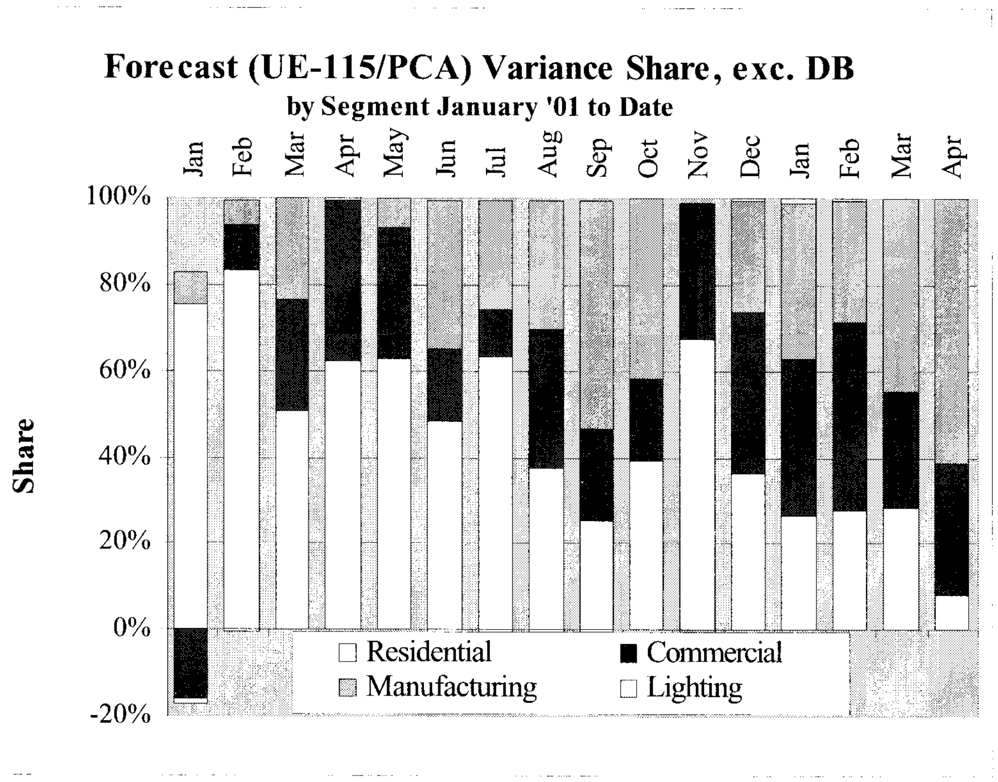
Sector Forecast Variance

- Deliveries to the Residential sector played a key role in the forecast variance, accounting for 50% to 60% of all delivery shortfall through July '01
- Since August '01 (except for Nov.) Non-residential sectors began to account for a larger share (over 60%) of shortfall



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Recent PCA Load Forecasts

- Retained UE-115 Core Forecast Model (sample period ending February '01 in the midst of the West Coast energy crisis and before the authorized rate increases) in November '01 and February '02 filings
- Used a revised Core Forecast Model in May '02 PCA filing (sample period extended through January '02)
- Used latest available DRI-WEFA forecast of the U. S. economy and the state's forecast of the Oregon economy
- Used latest large customers' information regarding operation schedule, plant closure and co-generation plans

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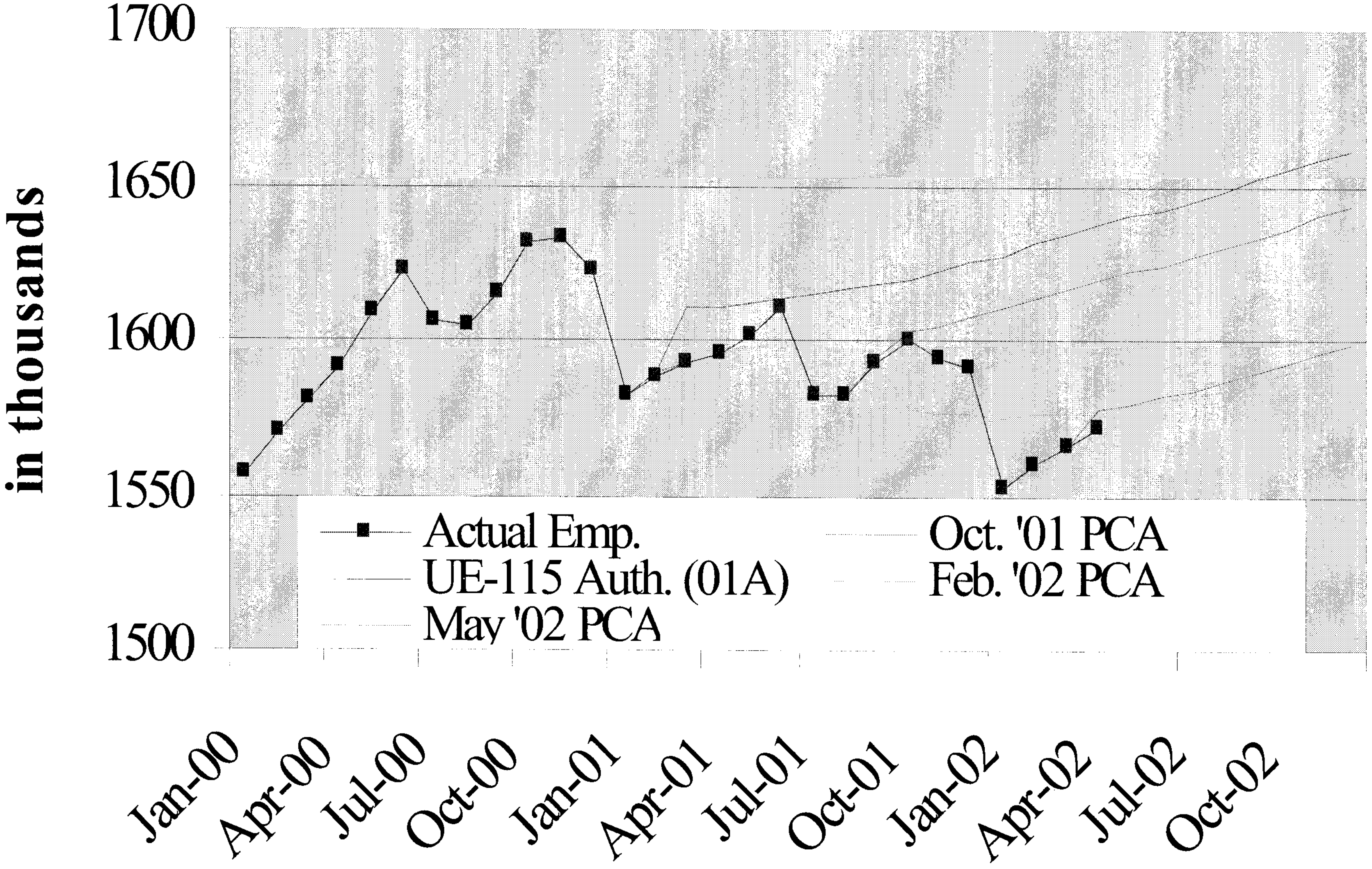
Why were the forecasts off so much?

- The economy
  - the expected economic slowdown turned into a full-fledged recession
  - the recession hit Oregon the earliest and hardest; Oregon lost 40,000 jobs (2.5% payroll) since Oct. '00, its 7.5% unemployment rate in April '02 (6% for the U.S.), while down from February's 8.1% still ranks as the worst among the 50 states
  - Oregon's dependence on manufacturing (15.1% share of total non-farm employment vs. 13.8% for the U.S.; 26.3% durable goods share or the GSP vs. 10.9% for the U.S.) makes it more susceptible to a capital-led downturn, spreading from traditional industries to high-tech manufacturing to software and services
  - The prominence of high-tech manufacturing, which helped buffer Oregon in the early-90's, became an albatross to the recovery as the 00's tech wreck intensified
- Impact of the West Coast energy crisis and customer response to rate increases were more significant than anticipated as customers cut back usage (behavior) and invested in energy efficiency measures and devices (structural), accounting close to 50 MWa, twice the 25 MWa impact estimated in UE-115
- The model, based on sample period when prices were mostly declining in real terms, was unable to capture changing relationships, e.g., electricity use per household and electricity-to-employment ratios

Oregon Non-Ag. Employment:
Actual and Forecasts



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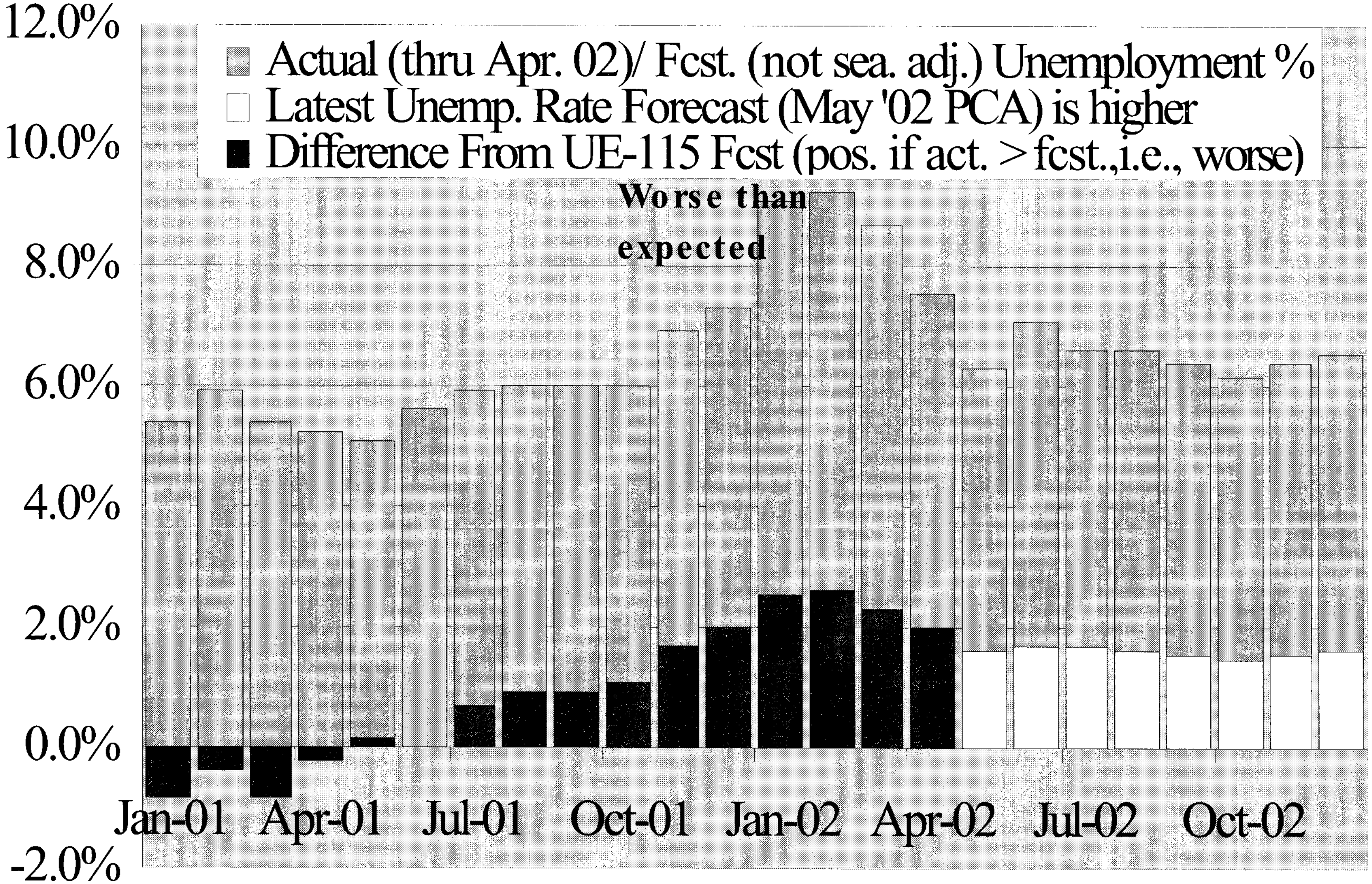
Oregon Unemployment Rate:

Actual vs. Forecast (Auth. UE-115)



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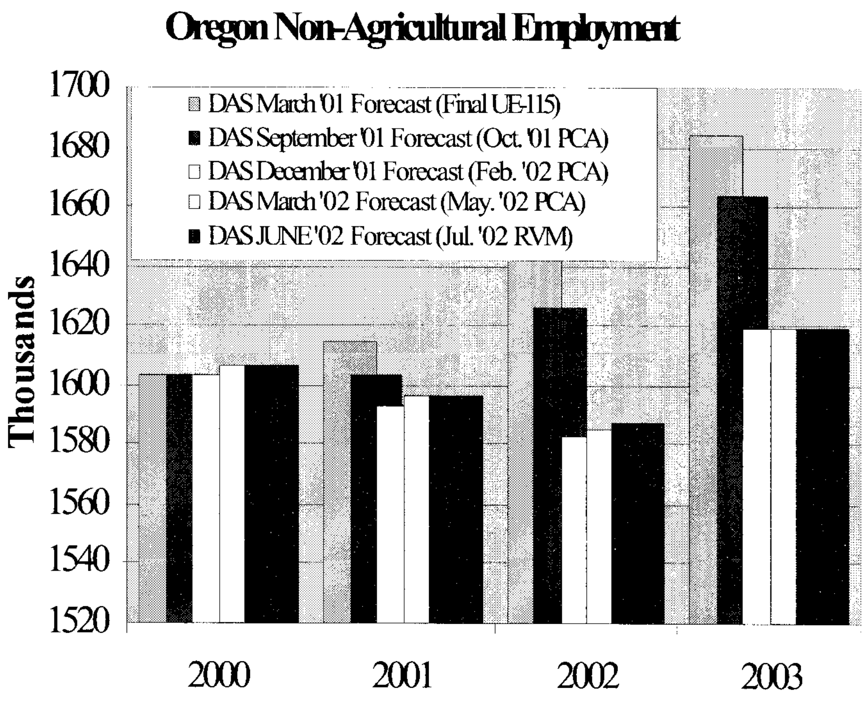

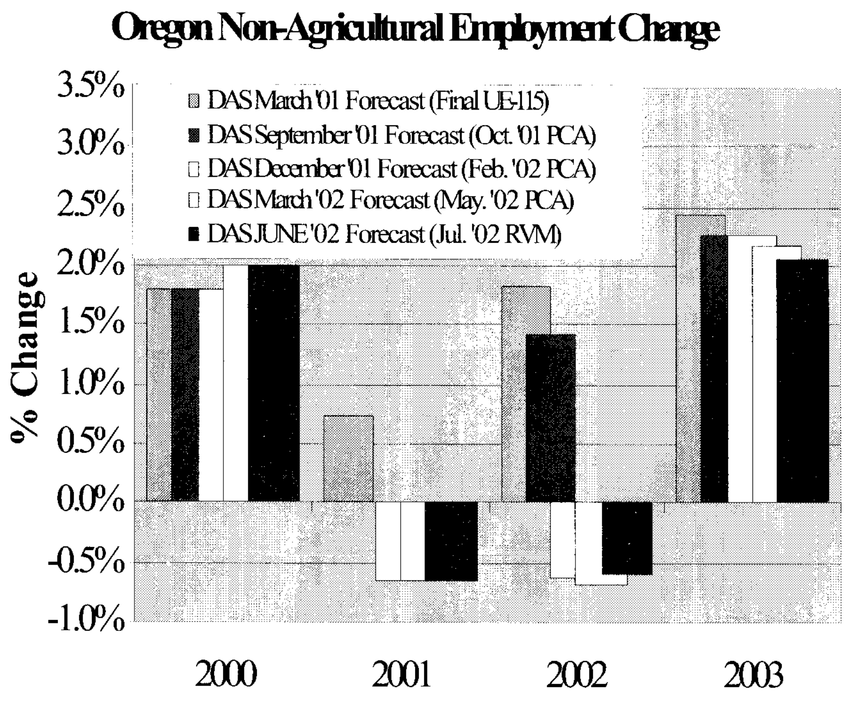

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Decomposition of Forecast Variance

- The latest retail load forecast (May '02 PCA filing) reduces 2002 (test-year) retail load by 1,465 million kWh, or nearly 180 MWa (less than the current 200 MWa under-run rate)

- The lower forecast, starting from a lower "actual base" (2001), results from updated (and lower) economic forecasts, changed large customer plans (plant closures, co-generation plans) and forecasts and a re-estimated model

- The variance between UE-115 and May '02 PCA forecasts (about 180 MWa) could be decomposed into

  - economic drivers: 33 MWa
  - large customer impact: 60 MWa
  - structural (model) 87 MWa

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May '02 PCA Load Forecast

- The May '02 PCA retail load forecast used a new model consisting of equations re-estimated with sample period extending through January '02
- This forecast calls for retail load, at normal weather, to decline 1.7% in 2002 as the recession persists, but to rise 2.3% in 2003 as the economy improves

	Million kWh			% Change		
	2001	2002	2003	'00 – '01	'01 – '02	'02 – '03
Residential	7,118	6,992	7,156	(3.8%)	(1.8%)	2.3%
Commercial	6,411	6,376	6,502	(1.0%)	(0.5%)	2.0%
Industrial	5,366	5,191	5,322	(6.4%)	(3.3%)	2.5%
Miscellaneous	202	205	208	1.5%	1.2%	1.9%
Total Retail	19,097	18,763	19,189	(3.6%)	(1.7%)	2.3%

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RVM and Future Load Forecasts

- Re-estimate new equations using sample extending through April 2002 for use in RVM retail load forecast to incorporate evolving relationships
- Use most-recent national (May 2002) and state economic (June 2002) forecasts
- Use latest large customer information regarding their future operation plans and forecasts
- Plan to re-estimate model every three months or so to capture behavioral and structural changes going forward

June 28, 2004

TO: Melinda Davison
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-161
PGE Response to ICNU Data Request 4.2
Dated June 14, 2004
Question 023

<u>Request:</u>
Please provide a Monet run with the most recent 12 months of actual load data replacing the assumed load forecast.

<u>Response:</u>
PGE objects to this request on the basis that it is vague and unduly burdensome. To incorporate 12 months of actual load data requires several assumptions. First, PGE forecasts loads on the basis of normal weather. It is unclear from the request if ICNU refers to actual loads on an actual or normal weather basis. Second, it is also unclear from the request if ICNU is referring to Cost of Service loads or Total System Loads. Finally, ICNU has run Monet in previous dockets and has the ability to do so in this docket. PGE sent ICNU a copy of the Monet model as filed on April 1, 2004 and PGE's actual loads over the last 12 months were provided in PGE's response to ICNU Data Request No. 019. Thus, ICNU could perform the requested study.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Redacted Direct Testimony of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities upon the parties listed below by causing the same to be mailed, postage-prepaid, through the U.S. Mail.

Dated at Portland, Oregon, this 30th day of June, 2004.

Ruth A. Miller

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