BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues.	)

DIRECT TESTIMONY ON POWER COSTS OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

(Confidential Information Removed)

June 30, 2006

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. PLEASE STATE YOUR OCCUPATION, EMPLOYMENT AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am a utility regulatory consultant and President of RFI Consulting, Inc. ("RFI"). I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Q. WHAT CONSULTING SERVICES ARE PROVIDED BY RFI?

A. RFI provides consulting services related to electric utility system planning, energy cost recovery issues, revenue requirement, cost of service, and rate design.

Q. PLEASE SUMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in Exhibit ICNU/101 attached to my testimony.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. My testimony addresses issues related to PacifiCorp's Generation and Regulation Initiatives Decision Tool ("GRID") model study of normalized net power costs for the projected test period, calendar year 2007. I also address the Transition Adjustment Mechanism ("TAM") update study filed in April 2006. My testimony on other issues will be filed on July 12, 2006.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend a number of adjustments to PacifiCorp's test year net power costs, resulting in a reduction to the Company's Oregon allocated net power costs. Table 1, below, shows the dollar impact and the approximate Oregon allocation of each of my proposed adjustments. The following is a brief summary of each proposed adjustment.

Short-Term Firm Transaction Adjustments

1. The short-term firm transactions modeled in GRID show a disproportionate number of below-market sales. Starting in late 2004, PacifiCorp took a short position on short-term firm trades and it will subsequently have to cover that position with more expensive purchases because market prices have increased. PacifiCorp's practice was imprudent because it exposed ratepayers to unnecessary price risks and resulted in much higher power costs.

Long-Term Contract Adjustments

2. PacifiCorp prices the Sacramento Municipal Utility District ("SMUD") contract at $37/MWh based on the price of the Southern California Edison ("SCE") contract. This treatment was first ordered by the Utah Commission because SCE was considered to be a prudent, contemporaneous contract that could establish a benchmark price for SMUD. This has become the standard treatment in Oregon as well. Because the SCE contract expires in September 2006, there is no longer an appropriate benchmark. Therefore, the SMUD contract should also be assumed to expire.

3. The Company does not include the NUCOR contract in GRID. This contract expires in December 2006, but it is likely to be renegotiated. I propose a placeholder adjustment for this contract.

4. I recommend removal of the Desert Power QF from the 2007 test year. This contract has prices that are now substantially above market. However, the project recently missed the expected 2006 in service date and it is unclear when it will begin operation.

5. PacifiCorp overstates the likely generation from the Georgia-Pacific ("GP") Camas cogeneration facility compared to recent trends.

Modeling Adjustments

6. I recommend the Commission reject steps 14 and 15 in the April TAM update. These updates are related to reserve modeling and constitute the very sort of "one-sided adjustments" that the Commission was concerned about in its final order in Docket No. UE 170. Further, GRID already produces an unrealistic dispatch of gas-fired peaking units due to unrealistic reserve modeling techniques.

7. The VISTA hydro modeling methodology overstates the likelihood of extreme hydro conditions while understating the chances of more typical conditions.

8. The Company uses actual outages from the 48 months ending September 30, 2005, to compute outage rates used in GRID. Over the past decade, outage rates for PacifiCorp units have substantially increased, resulting in much higher power costs. PacifiCorp's outage rates now exceed national averages. A major cause of these increased outages is personnel and maintenance errors. I have performed an analysis to remove these excessive and imprudent outages from GRID.

9. I recommend the Commission reverse the adjustments proposed by the Company related to ramping, station service, and the use of monthly outage rates. These adjustments are not industry standard practices and are not well supported.

10. The planned outage schedule assumed by the Company for 2007 is unrealistic compared to historical patterns and results in excessive costs. The Company assumes increased planned outages in the fall when market prices are high, rather than in the spring when lower prices prevail and maintenance is normally performed.

11. GRID uses an overstated minimum capacity for Cholla 4 and understates the maximum capacity of Dave Johnson Unit 3.

12. I recommend an adjustment to the generation from the Foote Creek wind project. The inputs used by the Company fall far short of the historical output of the facility.

13. I recommend an adjustment to capture the impacts of stochastic price variations. This adjustment reflects the benefits of increased sales on gas-fired units when the spread between market gas and electric prices is positive, and off-loading of gas plants when the spread is negative.

Table 1 identifies the impact on net power costs associated with implementing each of my proposed adjustments.

Table 1
Summary of Recommended Adjustments

		Total Company	Est. Oregon Jurisdiction
			SE 26.173%
			SG 26.628%
I. GRID (Net Power Cost Issues)			
1	PacifiCorp Request	$889,352,146	$234,793,413
A. Short-Term Transactions Adjustment		-$45,455,364	-$12,103,854
2	Short-Term Firm Prudence	-$45,455,364	-$12,103,854
B. Long-Term Contract Adjustments		-$36,006,813	-$9,587,894
3	SMUD Contract	-$18,527,654	-$4,933,544
4	NUCOR Contract	-$3,533,911	-$941,010
5	Desert Power	-$13,705,739	-$3,649,564
6	Cool Keeper	-$170,437	-$45,384
7	GP Camas	-$69,072	-$18,392
C. Modeling Adjustments		-$84,305,770	-$22,225,773
8	Extrinsic Value	-13,790,003	-$3,609,257
9	Reserve Modeling	-$25,800,363	-$6,811,425
10	Hydro Modeling (VISTA)	-$2,464,122	-$650,541
11	Station Service	-$4,271,158	-$1,127,607
12	Imprudent Outages	-$21,641,621	-$5,713,496
13	Reverse Ramping	-$3,681,010	-$971,805
14	Reverse DJ-3 Derate	-$3,676,112	-$970,512
15	Cholla 4 Minimum	-$467,775	-$123,495
14	Monthly Outage	-$2,294,779	-$605,833
15	Planned Outage Schedule	-5,330,981	-$1,407,406
16	Foote Creek Wind	-$887,846	-$234,396
Total Power Cost Adjustments		$165,767,947	-$43,917,521
Allowed - Final GRID Result		$723,584,199	$190,875,892

II. NET POWER COST ISSUES

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

A. Net power costs are the variable production costs related to fuel and purchased power expenses and net of power sales revenue. Net power costs comprise a substantial portion of the overall revenue requirement and therefore are a significant component of PacifiCorp's proposed base rates.

Short-Term Transaction Modeling

Q. DESCRIBE THE SHORT-TERM TRANSACTIONS MODELED IN GRID.

A. There are two types of short-term transactions modeled in GRID. Short-term firm transactions are firm purchased sales contracts with a term less than one year. GRID does not forecast or simulate such transactions. They are just a fixed input with pre-determined energy volumes and prices.[1/]

Secondary balancing transactions (hour-to-hour trades) are simulated in GRID. The model either sells or purchases this product at prices based on the input market forward price curve as needed to balance the system.

Q. DO YOU AGREE WITH THE GRID MODELING METHODOLOGY?

A. No. There are some serious problems with PacifiCorp's GRID modeling approach. The Company included only the trades that it had arranged as of the time it filed its TAM update in April 2006. By itself, this is quite problematic because many additional transactions will be arranged after the filing date. While the Company plans additional updates in the months ahead, many short-term firm

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1/ The model *accounts* for such transactions rather than *simulate* them. No matter what else changes in the model, the short-term firm transactions will remain constant in GRID.

trades will occur during the FY 2007 test year, days or only hours ahead of their actual delivery. Because the Company attempts to minimize its costs, it will naturally attempt to make profits on short-term trades wherever possible and reduce costs by achieving a better system balance. As a result, the volumes of short-term firm transactions will be understated in GRID, and net power costs will likely be overstated.

Because GRID does not model all short-term firm sales, it tends to overstate balancing (non-firm) transactions. In GRID, it is impossible to make a profit on secondary balancing transactions (other than arbitrage opportunities across markets) because purchase and sales prices are assumed to be equal in hourly markets. In actual practice, however, the Company will attempt to make a profit on all short-term transactions, both firm and balancing.

Q. HOW SUBSTANTIAL IS THIS PROBLEM?

A. The current filing assumes an average short-term firm transaction balance (the average volume of purchases and sales) of 10.3 million MWh. In contrast, for 2005, the actual average short-term firm volume balance was 40.6 million MWh. Consequently, GRID excludes approximately 75% of recent actual short-term firm transactions from the test year. PacifiCorp's method is systematically flawed because the Company continues to make trades as time passes, and it is safe to assume the objective of these trades is to reduce, rather than increase, power costs. Unless one assumes all the additional activity is merely a series of "wash trades" for no real purpose, the net effect should be to lower net power costs and better balance the system.

Q. IS THIS A PROBLEM THAT IS INHERENT IN THE USE OF A FULLY PROJECTED TEST YEAR?

A. Yes. The Company's approach was obviously unrealistic from the start because it was clear that a substantial portion of the actual trades would be excluded. In effect, the Company has presented what amounts to little more than a limited sample of the trades it will actually make in the test year. As I will show shortly, it is a very biased sample containing far more sales than purchases. Even worse, many of these sales are well below current market levels.

Q. WILL THIS PROBLEM BE SOLVED IF THE COMPANY UPDATES ITS FILING AS PART OF THE TAM PROCESS?

A. No. It is not possible in this case to include all short-term firm transactions because the test year extends well beyond the date of the last TAM update in November. Finally, the most significant problem is that the Company has exposed ratepayers to unnecessary price risks by arranging far more sales than purchases, many months in advance of the actual trade dates.

Q. PLEASE EXPLAIN.

A. Confidential Exhibit ICNU/102 presents a graphical summary of the short-term firm trades included in GRID. This exhibit was developed from the data provided in the Company's response to ICNU data request no. 1.9. Prior to January 1, 2006, the Company entered into 37 purchase transactions and 137 sales transactions for delivery in 2007. These transactions were all arranged after October 2004, but many of these deals were far in advance of their agreed-upon delivery dates. In fact, the average period of time between the transaction date and the delivery date was more than 25 months. Approximately 2/3 of the sales contracts PacifiCorp entered into had an average delivery date more than 24 months after the date the trade was arranged. This chart shows that the Company went very far forward with firm sales of a year or less. In simpler terms, PacifiCorp took a very short position in late 2004 and early 2005. The same data shows that at that time, the Company made almost no purchases. As a result, the Company clearly was in a short position rather than trying to balance a long position.

During the year prior to the filing date, market prices for power increased over 65%, according to PacifiCorp's forward price curves. As a result, the great majority of the sales transactions executed by the Company were below market as measured by the December 30, 2005 forward price curve used in the filing.

Q. HOW DO THESE BELOW MARKET TRANSACTIONS IMPACT NET POWER COSTS?

A. The number and volume of below market sales far outweighs the number and volume of below market purchases, particularly in the Palo Verde and Mid-Columbia markets. As a result, the GRID model makes a large number of balancing purchases in these markets to cover the short position. Exhibit ICNU/103 shows the balance of short-term firm sales and purchases versus balancing sales and purchases in these two markets. Because PacifiCorp is buying on the higher-priced balancing market to cover its sales of low price firm transactions in these markets, the net effect is a substantial increase in net power costs.

Q. WHAT ARE THE IMPLICATIONS OF THIS PROBLEM?

A. First, we are left with an obvious question of prudence. For the past several years, PacifiCorp's short-term firm sales and purchase volumes have been in a rough balance. Given that, it is quite difficult to understand why the Company would undertake such a substantial number of sales relative to purchases. The net effect was to put the Company in a position of betting on a decline in market prices, which never materialized. In fact, the opposite occurred, and market prices sky rocketed.[2/] This creates the need for the Company to cover its short position of low cost sales with high cost purchases. In other words, "buy high and sell low."

Second, while it is possible that the Company may be able to make profitable trades in the future to offset the additional costs of the below-market sales, it will not be possible to reflect all of the short-term firm transactions in the test year because trades that actually take place in 2007 will not be reflected in any of the TAM updates. This means that the additional benefits of a better balancing of the system and the numerous profit opportunities that the Company's traders will strive to exploit in the months ahead will not be reflected in rates. Consequently, the test year is biased against ratepayers. Likewise, a drop in market prices in 2007 could help the Company escape from this problem, but ratepayers would not see any of the benefits of that turn of events.

Third, for purposes of establishing permanent, normalized rates, it is unrealistic to assume that unanticipated market fluctuations will always work

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2/ There has been some drop recent drops in the market prices. However, the Company's forward curve used in the GRID model was prepared prior to the drop in market prices.

against the Company. In normal conditions, the Company will likely make as many (if not more) above-market sales as it does below-market ones. Likewise, under normal conditions, the Company will make as many below-market purchases as it does above-market purchases. Over time, the forward price curves will move in various directions, and the Company will likely find as many circumstances where it is above market as below. This being the case, it is unrealistic to assume that normalized rates should reflect a preponderance of below-market transactions. Indeed, in cases prior to 2000, the Company assumed it would make all short-term firm sales at market, and it would actually obtain a small positive margin from all such transactions. For these reasons, use of a skewed sample of the actual short-term firm transactions will not provide a reasonable estimate of net power costs.

Finally, the Company gets to choose when to file rate cases and can propose what test year to use. If it finds itself in a very profitable trading environment, it may retain the profits. If it accumulates trading losses, it may file a rate case. In either case, the Company may propose a test year that is most advantageous to it. Consequently, to assure a proper balancing of ratepayer and shareholder interests, the Commission should insist that the costs built into rates do not reflect such out-of-market trades.

Q. HAS THERE BEEN ANOTHER CASE IN WHICH THE COMMISSION WAS CONFRONTED WITH A PROBLEM RELATED TO OUT-OF-MARKET CONTRACTS ENTERED INTO FAR IN ADVANCE OF THE ACTUAL DELIVERY DATES?

A. Yes. In Portland General Electric ("PGE") Docket No. UE 139, the Commission made a disallowance related to four contracts that PGE entered into far in advance of the ultimate delivery dates. This case provides a strong precedent for the current proceeding.

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.
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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.

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

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

A. In this case, the argument for imprudence is even more compelling. First, the PacifiCorp transactions were sales, not purchases. Consequently, concerns about meeting future demand (which swayed the Commission to allow some of PGE's 2001 advance purchases) are simply not relevant. In fact, the data from GRID illustrates that these sales put the Company in a risky, short position. While a Company may arguably have prudent reasons to make purchases in advance of the ultimate need in order to assure supply, there is simply no need to make sales far in advance of the delivery date.

Second, many of the PacifiCorp sales were negotiated two to three years in advance of delivery. This is a comparable time frame to those disallowed by the Commission in UE 139.

In the end, PacifiCorp's decision to contract for sales far in advance of the ultimate delivery date exposed ratepayers to substantial risks, and the Company should not be allowed to reflect these costs in its power cost model.

Q. HOW DO YOU PROPOSE THE COMMISSION ADDRESS THIS ISSUE?

A. The simplest approach is to remove all short-term firm transactions from GRID. From a modeling perspective, this will result in secondary balancing transactions taking the place of short-term firm purchases and sales in GRID. This will price 100% of system balancing requirements at the forward curve price used in the model. While the Company might argue that this is unrealistic, in fact, under the Company modeling, 75% of system balancing requirements are already priced based on the forward curve (via the modeling of secondary balancing transactions), because, as shown above, the short-term firm trading volume in the model is only 25% of the 2005 levels. This recommendation is also consistent with the Commission's treatment of PGE's imprudent contracts in UE 139, because in that case the Commission re-priced those contracts on the basis of the forward curve available at the time. This adjustment reduces net power costs by approximately $80 million.

As a more conservative alternative, I recommend a disallowance designed to re-price only those contracts entered into before December 31, 2004. These contracts were all for sales 24 to 36 months forward. I believe this treatment is completely consistent with the UE 139 precedent. Pricing only these sales at the current forward curve reduces net power costs in the amount shown on Table 1.

Long-Term Contract Modeling In GRID

Q. DOES GRID MODEL LONG-TERM POWER CONTRACTS?

A. Yes. The Company includes the costs and energy produced by all of its long-term contracts in GRID, along with its thermal generation resources in order to project normalized net power costs. I will discuss issues related to PacifiCorp's long-term contracts in the following sections of my testimony.

Sacramento Municipal Utility District Contract

Q. DISCUSS THE CIRCUMSTANCES UNDERLYING THE SMUD CONTRACT.

A. This is a 30-year contract with a price that is far below market. The history of the treatment of this contract by the Oregon Commission has its roots in decisions made by the Utah Public Service Commission ("UPSC"). In 2001, the UPSC required a revenue imputation for PacifiCorp's contract with SMUD on the basis that the prices were unreasonably low. In its final order in Docket No. 01-035-01, the UPSC summarized the history of this issue:

> As in the immediately preceding general rate case for this Company, Docket No. 99-035-10, this Commission is asked to impute revenues to a 1987 long-term firm wholesale contract with SMUD to counter the contract's adverse impact on the net power cost portion of jurisdictional revenue requirement. In that Docket, the Commission did order imputation because the contract obligated the Company to serve SMUD at $16.85 per MWh at the time it was entered, a rate much below the then-current rate for power. In addition, SMUD paid the Company $94 million at the outset of the contract that it retained and was not used to benefit ratepayers. Nor was this the first time the imputation had been made. In connection therewith, both here and in other PacifiCorp jurisdictions, a contract with Southern California Edison (SCE) entered at about the same time for $42 per MWh had been considered an appropriate benchmark for imputation. The evidence in Docket No. 99-035-10 showed that the SCE contract had been renegotiated to a rate of $37 per MWh due to structural

> changes in the wholesale market. In other words, the Commission recognized that wholesale prices, which had fallen, were now on a different path. This, and the fact that the renegotiation was closer in time to the test period, persuaded the Commission to select the $37 rate as the basis for imputation, a rate indicating how such a contract might perform over time.

Re PacifiCorp, UPSC Docket No. 01-035-01, Report and Order at 24-25 (Sept. 10, 2001).

Q. HAS THE COMPANY MADE AN ADJUSTMENT TO ITS TEST YEAR TO REFLECT THE SMUD REVENUE IMPUTATION IN THIS AND OTHER JURISDICTIONS AS WELL?

A. Yes. Since the 2001 Utah case, the Company has used the $37/MWh price for imputation of revenue in all jurisdictions. While I have not objected to this treatment in the past few cases for Oregon, I do not believe the Oregon Commission actually decided that the $37/MWh was a reasonable price in a contested proceeding. While the figure has been accepted as part of settled cases, the Commission has not recently passed judgment on its use. There are two important reasons why the Commission should address this issue now.

First, wholesale power prices have continued to increase since the adoption of the Utah order in the 2001 case. Indeed, the SCE contract that was the basis for the $37/MWh was renegotiated and the most recent contract prices have been much higher. Consequently, the $37/MWh is no longer reasonable or compensatory.

Second, and even more significant, the SCE contract terminates in September 2006. Originally, SCE was a 20-year contract. Because SCE was selected by the Utah Commission as a prudent benchmark contract contemporaneous to SMUD (actually, SCE post dates SMUD), the basis for the

$37/MWh will no longer exist. Consequently, the Commission must decide again on the proper basis for handling this issue for the remaining 10 years of the SMUD contract.

Q. WOULD IT BE PROPER TO USE THE ACTUAL CONTRACT PRICE?

A. No. The contract price (approximately $18.5/MWh in recent months) is not compensatory. The Company entered into this contract after receiving an up front payment of $94 million, which it retained for itself. As a result, the Company, not ratepayers, should bear the risk of this contract until it expires.

Q. WOULD IT BE APPROPRIATE TO USE THE $37/MWH PRICE?

A. No. This price is substantially below the current market, and below even the most recent renegotiated price of the SCE contract. The SMUD contract is primarily for on-peak power, so ratepayers are clearly subsidizing the contract even at $37/MWh.

Q. WHAT THEN IS YOUR RECOMMENDATION?

A. I believe the most equitable approach is to assume that, like the SCE contract, the SMUD contract would have terminated after 20 years. As a result, I would remove the SMUD contract from the power cost study. This is equitable because, after the adoption of the $37/MWh price several years ago, the contract has been subsidized by ratepayers due to its below-market price. Because it obtained a benefit from use of the SCE contract as a pricing benchmark, the Company should now be required to assume all of the risks of the limited term of the SCE contract. Removing the SMUD contract from the test year reduces power costs by the amount shown on Table 1.

NUCOR Company Contract

Q. DESCRIBE THE NUCOR CONTRACT.

A. NUCOR provides interruptible capacity to the Company, based on a contract expiring on December 31, 2006. One of the most important aspects of the NUCOR contract is the reserve capacity it provides. Though the contract will expire soon, it is unrealistic to assume it will not be renewed.

Q. WHY IS IT NECESSARY TO INCLUDE THE NUCOR CONTRACT IN GRID NOW?

A. This adjustment is merely a placeholder for a future update, so that the NUCOR contract will not be overlooked. In order to assure that the Company includes the NUCOR contract in its subsequent updates, I include the NUCOR contract, based on current contract terms, for all of 2007. When the new contract is negotiated, it can be modeled in a GRID update. By including the contract in GRID now, the Company will have incentive to renegotiate the contract, and it will know that it may recover the costs associated with the contract as well.

Desert Power QF Contract

Q. PLEASE EXPLAIN THE DESERT POWER QF ISSUE.

A. The Desert Power QF was expected to be on line in 2006 and was included in GRID for all of 2007. I became aware of this issue too late in the case to obtain discovery responses. However, based on discussions with various sources, I understand that the project is not expected to come on line prior to June 1, 2007. The reasons for this situation are not completely clear, however, it appears that problems related to the project's interconnection have surfaced. Also, there is a gas pressure problem that may also adversely impact the operation of the facility.

Compared to market purchases in GRID, the contract price is well above market levels at the present time.

The pricing for the contract was established by the Utah Commission, pursuant to a settlement agreement in Docket No. 03-035-14. That agreement requires the facility to be on line before June 1, 2007. If that milestone is not met, it is unclear what pricing will be in place for the contract. While sources close to the project remain confident that it will meet that requirement, there is certainly some uncertainty surrounding the project at this time. If the June 1, 2007 milestone is not met, it is possible that the Utah parties would then see a need to revisit the contract prices, as the original assumptions underlying those prices would not have been fulfilled. Further, Desert Power's failure to meet contractual requirements would provide PacifiCorp with an opportunity to renegotiate the contract and bring prices back in line with the market.

At this time, there is little assurance the facility will be on line in 2007. If it does come on line after June 1, 2007, if priced at the then current avoided costs, it should be revenue neutral to ratepayers whether the contract is modeled in GRID or not. As a result, I recommend removing the project from GRID. If the Company resolves the issue before the last GRID update is performed, it could be included at that time.

Q. ASSUMING THE DESERT POWER QF DOES MEET ITS JUNE 1, 2007 ON-LINE DATE, WHAT WOULD BE THE IMPACT ON NET POWER COSTS?

A. In that case, net power costs would be reduced by $6.86 million, roughly half of the adjustment shown on Table 1.

Thermal Dispatch/Reserve Modeling Adjustments

Q. DO YOU HAVE ANY CONCERNS REGARDING MODELING OF THERMAL DISPATCH IN GRID?

A. Yes. I am concerned that the simulated operation of gas-fired units in GRID is highly unrealistic. In reviewing the GRID hourly dispatch, I found that, once dispatched, gas-fired combustion turbines ("CT") typically run exclusively at minimum loading levels. However, this operation of gas units is simply not representative of actual system operation. Exhibit ICNU/104 is a graph comparing the most recent actual and GRID (simulated) capacity duration curves for West Valley CT Unit No. 1. This unit is typical of PacifiCorp's CTs. In actual operation, once dispatched, the CT unit normally operates at a range of loadings up to their maximums. For the 12 months ended May 2006, the unit only operated for 2300 hours. However, in GRID the unit runs almost exclusively (once dispatched) at its minimum loading (15 MW) and runs for more than 4000 hours per year. This unrealistic operation (in GRID) causes the Company to lose opportunities to make sales from CT units during periods with high market prices while also resulting in CTs running at inefficient minimum loads for thousands of hours per year.

Q. WHAT IS THE CAUSE OF THIS PROBLEM?

A. There may be more than one cause. However, it appears that a very important contributing factor is the reserve and regulation modeling in GRID. It appears that GRID is requiring the CTs to operate at minimum loadings to meet reserve requirements. This type of operation is simply not seen in actual practice, leading me to question whether GRID is realistic in its modeling of reserve and regulation requirements.

Q. DESCRIBE STEPS 14 AND 15 IN THE APRIL TAM UPDATE.

A. The Company maintains that a new analysis of GRID inputs indicates that an even higher reserve requirement should be used in GRID. PPL/503, Widmer/3. This adjustment increased net power costs by $17.9 million. It is referred to by the Company as Step 15 of the April TAM update. Further, the Company increased requirements for contingency reserves in GRID to account for the cost of providing auxiliary service for non-PacifiCorp generation. This was Step 14 in the April TAM update and increased costs by $7.8 million.

Q. DO YOU AGREE WITH THE ADJUSTMENTS IN STEPS 14 AND 15?

A. No. It seems very clear that the GRID model is doing a very poor job of representing actual system operation of CTs, due to the reserve modeling logic. These new updates make the operation of CTs even more unrealistic. Referring again to Exhibit ICNU/104, the operation of West Valley unit 1 after Step 15 is also shown. In this scenario, the unit runs even more hours at minimum load in GRID (close to 4500 hours per year). Thus, Steps 14 and 15 produce results that are even more at odds with actual operation.

Q. DO YOU HAVE DATA THAT DEMONSTRATES THIS PROBLEM EXISTS FOR ALL OF THE PACIFICORP CTs?

A. Yes. Exhibit ICNU/105 summarizes statistics for all of the CTs in GRID Step 15 as compared to actual. It shows that the operation of these units in GRID is quite unrealistic and that the same problem of excessive operation at minimum load exists to varying degrees for all of the CT units. As a result, it is clear that this modeling problem impacts all CTs, not just West Valley Unit 1.

Q. IS THE BASIS FOR THE MODELING CHANGE AN INCREASE IN ACTUAL RESERVE REQUIREMENTS?

A. No. The Company is not claiming that the operating requirements of the system have changed; rather, PacifiCorp asserts that the model needs adjusted inputs to reflect spinning and ready reserve requirements. In effect, the Company is forcing the model into even more unrealistic operation.

Q. HAVE YOU REVIEWED THE NEW ANALYSIS THE COMPANY RELIES UPON TO SUPPORT STEP 15?

A. Yes. I obtained the study and discussed it thoroughly with Mr. Widmer and his staff on Friday, June 16. I have also reviewed substantial discovery related to this issue in the several current or recent cases I have been involved with in Oregon, Utah, Wyoming, and Washington.

<u>First</u>, the Company indicates that the modeling inputs originally used in GRID were suggested by the real time (operations) staff. I had a meeting with Mr. Widmer and two members of the real time staff in November 2004 to discuss regulation and reserve modeling in GRID. Based on that meeting, I believe the Company actually overstated the reserve and regulation requirements in GRID, as compared to actual practice. I raised this issue in several other cases, and all were resolved by settlement.

<u>Second</u>, the Company does not contend that the changes to GRID were the result of any additional input provided to the GRID modeling group from the real time staff. In fact, nothing in the actual operation of the system has changed.

Rather, PacifiCorp performed a new statistical analysis, comparing a computed regulation requirement to that used in GRID. On this basis of this analysis, the Company *now* contends that GRID is understating the regulation requirements.

Third, the regulating margin requirement is not based on a specific formula or a fixed MW requirement. Rather, it is a "performance based" requirement. The amount of regulating margin required is the amount necessary to meet the North American Electric Reliability Council's ("NERC") Control Performance Standards. There is no specific formula that equates this requirement to a regulating margin requirement.

In contrast, the new PacifiCorp analysis defines regulating margin as the difference between the average 5 minute hourly peak demand and the hourly average demand. This is not the NERC requirement, as NERC only requires that its standards for area control errors and frequency errors be met. In the end, the level of regulating margin used in GRID is a subjective input. In the past, the Company relied on the inputs developed based on the judgment of its real time personnel. Now the Company is changing the inputs based on a flawed analysis. Thus, the new inputs are unnecessary and overstate requirements. Because GRID is already committing far too much CT capacity for providing reserves, this results in additional costs.

Q. ARE THERE ANY OTHER PROBLEMS WITH THE RESERVE MODELING INPUT CHANGES PROPOSED BY THE COMPANY?

A. Yes. Part of the change is due to reflecting contingency reserve requirements for QFs and other generators located in the PacifiCorp control area that are not owned by the Company. The Company should be required to demonstrate that in computing the avoided costs for those generators that it took into account the additional reserve requirements. If the Company has just now discovered this requirement for purposes of GRID, it is not safe to assume the additional reserve requirements were included when avoided cost rates were set. In UM 1129, for example, GRID runs (prepared prior to this data change) were used to establish the tariff prices. If the Company failed to reflect the additional reserve requirements for QFs, when avoided costs were set, then the Company should be held responsible for covering the cost of that oversight.

Q. ARE THESE TYPES OF MODELING CHANGES REALLY APPROPRIATE FOR THE TAM UPDATE?

A. No. I do not believe substantial modeling changes of this sort were the type of changes that the Commission envisioned when it approved the TAM in Docket No. UE 170. There is no reason the Company could not have presented its argument for a change in reserve modeling in the initial filing. I do not believe the TAM April update was intended to deal with complex issues of this nature. The TAM update process provides less time than a general rate case for dealing with new issues and does not provide intervenors any opportunity for rebuttal.

PacifiCorp's proposal is very reminiscent of PGE's resource valuation mechanism ("RVM") cases a few years ago when parties complained of the "one-sided" nature of PGE's changes to its power cost model in the annual updates in the RVM process. The Commission ultimately approved an agreement by the parties that no modeling changes would be proposed in the annual update to the RVM for a period of two years, and the Commission indicated that it would review the RVM in PGE's next rate case. Re PGE, OPUC Docket No. UE 149, Order No. 03-535 at 3 (Aug. 29, 2003); Re PGE, OPUC Docket No. UE 172, Order No. 05-1140 at 3 (Oct. 25, 2005). In approving the TAM, the Commission acknowledged the issues and expressed concerns about the TAM becoming a "one-sided" process:

> We are somewhat concerned about establishing the TAM with its annual update because there is a certain amount of one-sidedness to PacifiCorp's annual updates without concomitant adjustments by intervenors and Staff. We will continue to look at the TAM and investigate to whatever extent we believe is necessary.

Re PacifiCorp, OPUC Docket No. UE 170, Order 05-1050 at 21 (Sept. 28, 2005). As a result, I believe the Company should not be allowed to make this sort of one-sided adjustment through the TAM process given the constraints placed on opposing parties.

Q HOW HAVE YOU ADDRESSED THIS PROBLEM?

A. I recommend not implementing Steps 14 and 15 at this time. Instead, the Company should be required to analyze the modeling of CTs in GRID and develop new logic that is more realistic. Once that is done, the Company might evaluate the reserve modeling inputs in the context of a full general rate case. Reversing these changes reduces net power costs by the amount shown in Table 1.

VISTA Hydro Modeling

Q. ARE YOU FAMILIAR WITH THE VISTA HYDRO MODELING TECHNIQUES?

A. Yes. I participated in two workshops related to the VISTA modeling conducted by the Company as part of its activities in Docket No. UE 170. I have also examined this issue as part of my work in recent rate cases in Utah, Washington, and Wyoming.

Q. HOW DOES VISTA DIFFER FROM THE HISTORICAL 50 WATER YEAR MODELING APPROACH?

A. VISTA does not use traditional water year modeling. Rather, VISTA uses a set of three "exceedence" levels representing dry, wet, and median hydro conditions. This data develops the hydro generation scenarios for each resource based on historical stream flow data.

Q. WHY DID PACIFICORP ADOPT THE VISTA MODEL?

A. Mr. Widmer has testified that the hydro data available from BPA was "growing stale."[3/] During the VISTA workshops, the Company also indicated that BPA was no longer sharing supporting information. Consequently, the Company indicated it could no longer document the fifty water years of data it traditionally used in its power cost modeling.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE VISTA MODELING?

A. Yes. There are two serious (and related) problems with the VISTA data. The first problem is that the data used by VISTA was not available for all of the hydro resources for the same years or from the same sources. Confidential Exhibit ICNU/106 shows the actual VISTA hydro data and the years for which it is available. The source of this data was discovery requests in the recent Washington rate case and the inputs to the Washington GRID model.[4/]

The exhibit shows that the VISTA data is completely inconsistent. The data spans periods from 14 to 40 years from 1948 to 2004. There is no period of

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3/ Re PacifiCorp, OPUC Docket No. UE 170, PPL/600, Widmer/18.

4/ In the last Washington case, the Company prepared a "pseudo" 40-year hydro database in GRID. As part of that process, it revealed the actual historical data available for each hydro resource. The Company has indicated it would be too burdensome to update this data.

time, not even a single year, where the Company has comparable water year data for all of its hydro resources. As a result, it is impossible for the Company to provide its traditional multiple water year analysis.

It is apparent that there is no consistency in the data sources used for the various plants. While this may not necessarily be a serious problem by itself, it does reduce my confidence in the VISTA modeling. However, a more serious problem is the manner in which the Company used these disparate data sources to create the scenarios used in GRID.

Q. PLEASE EXPLAIN.

A. PacifiCorp's hydro resources are located on several different river systems: the Columbia, Lewis, Klamath, and Umpqua Rivers in the west, and the Bear River in the east. While stream flows on a given river are such that there is a very high (though still imperfect) correlation between the output of generators on the same river for a single month or year, that is certainly not the case for different river systems. Because the Company lacks a consistent set of data for all of its river systems, it is impossible (based on the VISTA data) to make a determination of the correlation between generation of resources on different rivers. Therefore, the Company had to make an assumption as to the correlation between the flows on the different rivers. In the end, the Company decided that generation from all of its hydro resources was perfectly correlated across rivers systems and throughout the year.

This means that all of the hydro resources are assumed to experience their median, best, and worst conditions simultaneously. Indeed, it is assumed that generation from all hydro resources moves in lockstep. For example, the Company assumed that if the western system hydro resources were having a “dry” year, the same would be true for the Mid-Columbia and even the eastern hydro resources. Consequently, the VISTA “dry” case assumes that all three major resource systems will experience a drought. The same is true for the “median” and “wet” hydro scenarios.

Even more problematic is the manner in which the Company constructed various scenarios. In the “dry” cases, it was assumed that every generator experienced a “dry” month every single month of the year. The same is true for “median” and “wet” cases. In the end, this process produces highly unrealistic results and overstates the likelihood of extreme conditions, because the “dry” and “wet” scenarios will not happen for all river systems at the same time and certainly will not all occur each month of the year.

Q. WHAT IS THE FUNDAMENTAL PROBLEM WITH THE VISTA MODEL?

A. The most substantial problem is that VISTA overstates the likelihood of extreme events, whether they be years of drought or flood conditions. In the end, this process tends to increase power costs and reduce hydro generation. I have raised this issue in prior cases, and the Company has acknowledged that the original VISTA method (which used 19 rather than 3 exceedence levels) was unrealistic. ICNU/107, Falkenberg/1. However, while the Company acknowledges that reducing the number of exceedence levels increased hydro generation, it continues to rely on the same flawed approach (albeit in a simplified form) in this case.

Q. DO YOU HAVE A SOLUTION TO THIS PROBLEM?

A. At this point, it is not possible to develop a comprehensive solution to the hydro modeling problem, given the lack of data for overlapping years in VISTA for the various river systems.

To address the problem for purposes of this case I computed the mean hydro generation from the data available from the 2005 Washington case. The mean can be computed more correctly from inputs to the VISTA model and does not depend on the shape of the distribution. The exceedence levels (wet, dry, and median) are all a function of the shape of the distribution, which is unrealistic and mathematically inaccurate. The results of this adjustment are shown in Table 1.

Q. IS THE WASHINGTON CASE DATA UP TO DATE?

A. It may not be completely up to date, but actual hydro generation changed little from that case, since the Company relied on a 2007 test year for its power costs in the Washington proceeding. I asked Mr. Widmer if updated data in this format was available, and he indicated it was not. Further, I tested these results by comparing them to the median hydro scenario. The median case is closest to the mean, and is a scenario Mr. Widmer himself has recommended in other cases. The results confirm the reasonableness of my approach based on the computed mean hydro conditions.

Thermal Deration Factors

Q. EXPLAIN THE SIGNIFICANCE OF THERMAL DERATION FACTORS IN GRID.

A. In GRID, thermal deration factors (also called outage rates) control the amount of generation available from thermal units. The more energy available, the lower net power costs. If a generator has an average outage rate of 5%, GRID assumes a thermal deration factor of 95%. This means that only 95% of the unit's capacity is available to produce energy. The remaining capacity is assumed to be permanently on outage. The Company uses a compilation of outages over the most recent forty-eight month historical period (April 2000 to March 2004) to compute the deration factors for its thermal plants. The purpose of using forty-eight months is to "normalize" or smooth out variations that might affect a single year.

Q. ARE THERMAL DERATION FACTORS AN IMPORTANT DRIVER IN OVERALL NET POWER COSTS?

A. Yes. PacifiCorp's thermal outage rates have increased substantially in the past five to ten years. Exhibit ICNU/108 shows that PacifiCorp's outage rates have increased by 36% compared to those used in the UE 111 test year for the same units. Because outage rates for larger units have increased by more than smaller ones, this has resulted in an increase of 42% in capacity on outage (i.e., the average amount of capacity out of service due to forced outages) assumed in the power cost study. This is an increase of 199 MW, or nearly the same capacity as the West Valley CTs. More troubling is the fact that more than 70% of PacifiCorp generating units have seen their outage rates increase over the past seven years.

Q. WHY DID YOU COMPARE 2006 TO 1999 OUTAGE RATES?

A. I have been analyzing PacifiCorp's outage rates since 1997, and there has been a continued upward trend to the present time. The 1999 case figures were worse than the 1997 four-year average, for example. I used 1999 figures as the base because that was prior to the Hunter outage that occurred in November 2000. The current four-year average likewise excludes the Hunter outage. Thus, this presents a fair comparison to establish meaningful trends. This is not a case of being "selective" to make a point.

Q. HAS THE INCREASE IN OUTAGE RATES INCREASED POWER COSTS?

A. Yes. To estimate this cost I used GRID to compute the change in net power costs resulting from a 10 MW change in coal capacity. I then applied this result to develop an annual average cost of the increased amount of capacity on outage. As shown in Exhibit ICNU/108, the result is more than $73 million per year on a total Company basis, which results in an increase in cost to Oregon of nearly $20 million per year. An additional problem is that the increase in outage rates has also lead to the need for additional thermal capacity, further increasing system costs. The increase in capacity on outage (199 MW) is equivalent to capacity of the West Valley plant.[5/]

Q. IN PRIOR CASES YOU HAVE RAISED CONCERNS REGARDING PACIFICORP'S OUTAGE RATES AND THE COMPANY HAS CONTENDED THAT ITS OUTAGE RATES ARE BETTER THAN THE NERC AVERAGES. IS THAT STILL THE CASE?

A. No. Exhibit ICNU/109 compares the PacifiCorp outage rates used in GRID with comparable figures for peer group plants developed from the NERC Generation Availability Data System (GADS) report for the period 2001 through 2004. This is the most recent report available. The figures demonstrate that if PacifiCorp's plants performed up to the NERC average for peer group plants, the Company

5/ The West Valley annual revenue requirement is $16.6 million.

would have the equivalent of 122 aMW of additional capacity available. This is equal to the capacity of the Gadsby CTs and results in added energy costs of $12 million per year for Oregon.

Q. IS PLANT AGING A REASONABLE EXPLANATION FOR THE DECLINE IN AVAILABLITY OF PACIFICORP'S GENERATORS?

A. No. The NERC averages for coal plants show little change over the years, even though virtually no new coal plants have been added to the national generator fleets. Thus, the NERC averages reflect plant aging and no decline in performance is apparent. See ICNU/110, Falkenberg/1. This clearly indicates that, as other utilities' coal plants have aged, there has been no decline in plant reliability. PacifiCorp should not be allowed to use plant aging as an excuse for its own decline.

Q. COMPARISON TO NERC AVERAGE FIGURES DOES NOT DIRECTLY ADDRESS PRUDENCE. IS THERE EVIDENCE THAT THE INCREASE IN OUTAGE RATES IS DUE TO IMPRUDENT OPERATION AND MANAGEMENT OF PACIFICORP'S RESOURCES?

A. Yes. To examine the issue of prudence, I examined "Root Cause Analysis" ("RCA") reports for a sample of more than 30 of the largest outages that occurred at PacifiCorp's coal-fired generators during the 48-month period ending September 30, 2005. I analyzed the RCA reports and determined whether the cause of the outages was due to personnel or maintenance errors, or other avoidable causes. It is important to point out that PacifiCorp did not report the outages to NERC as being due to personnel or maintenance errors in any of the cases.[6/] Instead these outages were all reported as having causes other than personnel or maintenance errors.

Despite PacifiCorp's characterization, I found a substantial number of situations where outages were recognized in the RCA to be due to personnel or maintenance errors, or other avoidable problems.

Q. CAN YOU PROVIDE SOME EXAMPLES?

A. Yes. [redacted] ICNU/111, Falkenberg/3-4.

[redacted] Id. at Falkenberg/6-7.

[redacted] Id. at Falkenberg/9-10. [redacted] Id.

[redacted] Id. at Falkenberg/12-13. [redacted] Id.

6/ PacifiCorp coded a very substantial number of outages due to such causes, but these tended to be small events, generally lasting only a few hours. The energy lost in such events has also been increasing substantially over the years.

[redacted] Id. at Falkenberg/15-16.

[redacted] Id. at Falkenberg/17. It might be argued that this problem was not PacifiCorp's fault. However, in UE 88, the Commission determined that the utility is in a better position than ratepayers to prevent a failure due to defective products and should not be permitted to pass on costs related to a potential manufacturer defect.[7/]

In addition, the Company identified [redacted] due to causes that it reported to NERC as being due to operator or personnel errors. These events resulted in [redacted] lost energy over the 48-month period and resulted in additional costs of $1.7 million in the 2007 GRID study.

[7/] The Commission stated: "We adopt TBA's finding that PGE behaved prudently with respect to the steam generator degradation. However, we disallow the steam generator costs incurred since 1991 and exclude the cost of replacing the steam generators from the imputed costs of running Trojan in the net benefits analysis. Although PGE's behavior was not faulty, PGE and the ratepayers are the only two parties to whom we can assign or impute steam-generator costs. As between those two parties, PGE is better situated to recover its costs from the manufacturer of the steam generators. Moreover, it is fair that shareholders bear some of the consequences of management investment decisions." Re PGE, OPUC Docket No. UE 88, Order No. 95-322 at 3 (Nov. 29, 1995).

Q. HOW DO YOU RECOMMEND THE COMMISSION ADDRESS THIS PROBLEM?

A. The Commission should remove imprudent and unreasonable outage costs from the GRID study. I believe the data I reviewed constitutes a large enough sample to impute the results to outages overall. My analysis indicates that about 7.7% of all energy lost due to outages and derations was due to the types of avoidable errors discussed above. As a result, I reduced the outage rates for PacifiCorp generators by 7.7%, resulting in a reduction to net power costs in the amount shown on Table 1. I believe this is a very reasonable adjustment. It is far less than the cost penalties based on imputing the historical performance the plants achieved (as demonstrated by the four-year average from the 1999 case) or from imputing the NERC peer group averages.

Even if the Commission were not to impute the results of my sample to all PacifiCorp's generator outages, the Commission should at a minimum remove the imprudent outages identified above from the GRID study. This results in a reduction of $6.0 million from net power costs on a total Company basis.

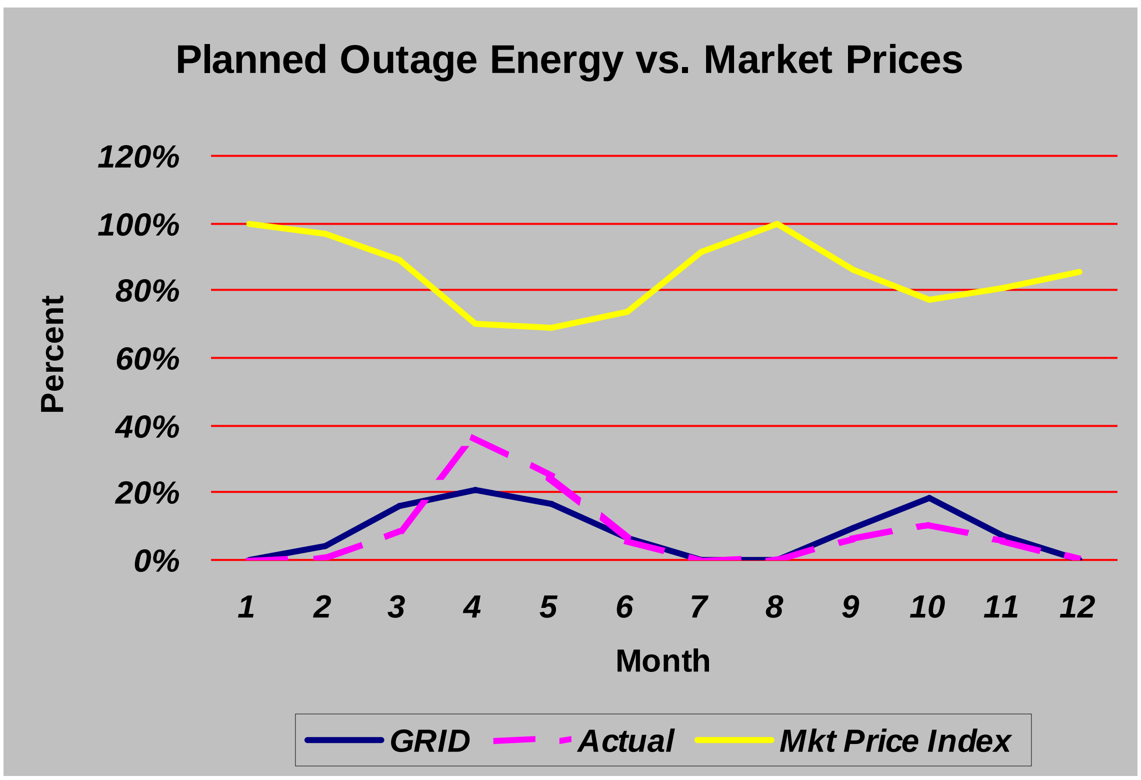
Planned Outage Schedule

Q. WHAT ARE PLANNED OUTAGES?

A. Planned outages represent times where generators are taken out of service for planned repairs and maintenance. Plants are typically taken down once per year for scheduled work. This work is normally scheduled during times when demand is low, and therefore, market prices are at their lowest levels.

Q. DOES THE COMPANY USE THE ACTUAL GENERATOR MAINTENANCE SCHEDULE FOR 2007 IN GRID?

A. No. The Company uses a "normalized" maintenance schedule. ICNU/112, Falkenberg/1. Given that the planned maintenance schedule can be changed in response to forced outages and other events, use of a normalized maintenance schedule is reasonable. However, I do not believe that the schedule actually used in GRID is a reasonable representation of a normalized maintenance schedule. The figure below illustrates the problems with the planned outage schedule assumed in GRID.



Q. PLEASE EXPLAIN THIS FIGURE.

A. This graph compares the actual amount of coal-fired generation that is unavailable due to planned outages for the 48-month period ended September 30, 2005, to the amount assumed in the GRID schedule. Superimposed on the chart is an index showing the market price assumptions built into GRID.

As is apparent from the chart, the actual planned outages have traditionally been scheduled to coincide with the low market price periods in the spring and fall. As the chart shows, spring has the lowest market prices, and the Company traditionally has performed most of its maintenance during these months.

In contrast, in GRID, the Company assumes that more outages will occur in the winter months and in September and October as compared to actual history. In both cases, the planned outages are assumed to occur during periods when higher market prices prevail.

A truly optimal schedule might place all maintenance during the period from April through early June. This would be impractical. It is unlikely that the Company could actually accomplish that schedule given the logistical problems of having planned outages on all of its coal plants in just three months. The chart does clearly show that the Company has traditionally performed far more maintenance in the low cost spring months than during the rest of the year. This provides a better basis for establishing a normalized schedule. PacifiCorp's "normalized" schedule in GRID does not make economic sense and is contrary to actual history. The Commission should reject it.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission adjust the model to assume a more realistic planned outage schedule. I have computed the impact of using the historical pattern of planned outage energy in place of the sup-optimal schedule assumed by the

Company. Because this pattern is based on the actual historical schedules used, it is clearly a feasible solution and it produces far more optimal results than the schedule assumed by the Company. The results of this adjustment are shown in Table 1.

Monthly Modeling of Forced Outage Rates

Q. EXPLAIN THE DIFFERENCE BETWEEN PLANNED AND UNPLANNED OUTAGES.

A. As discussed above, planned outages are scheduled in advance for routine service. To the extent possible, this schedule is developed to minimize costs. Unplanned outages can occur at any time and represent random failures.

Q. HOW DOES THE COMPANY MODEL UNPLANNED OUTAGE RATES IN GRID?

A. The Company computes a different unplanned outage rate for each month based on the 48-month rolling average. This procedure marks a significant departure from the modeling methods used by the Company for the past ten years or more. In the past, the Company assumed that unplanned outages would occur with the same probability every month of the year. In this case, the Company now assumes outage rates will vary by month.

Q. IS THIS AN INDUSTRY STANDARD PRACTICE?

A. Most definitely not. PacifiCorp's approach is quite unusual and certainly not industry standard. While I am aware that a few utilities have briefly experimented with modeling seasonal outage rates, the vast majority of utilities assume a constant outage rate throughout the year. The primary reason for this is that there are few physical factors affecting power plant operation that would result in outage rates varying on a monthly or seasonal basis. There is really no engineering basis to assume a generating unit would be more reliable in January than July, for example.

Further, unplanned outages are quite random in nature, and use of monthly statistics can produce very misleading results. For example, a unit could be out the entire month of May, resulting in a 100% outage rate for that month. Assuming the unit had a 10% outage rate otherwise, the Company's method would assume that every May, there was a 32.5% ((100+3*10)/4) chance the plant would be out of service, but only a 10% likelihood for the remaining eleven months. Rolling a single "bad month" into the overall 48-month average would produce a 48-month outage rate of 11.875% ((47*10+100)/48) overall. I submit that a single outage rate of 11.875% every month is more realistic than assuming a 32.5% outage rate each May and a 10% outage rate otherwise.

Q. DO YOU HAVE AN EXHIBIT THAT FURTHER ILLUSTRATES THE FALLACY OF PACIFICORP'S APPROACH?

A. Yes. Exhibit ICNU/113 shows an analysis of the outage rates for Jim Bridger Units 1-4. Because these units are all of the same size, fuel type, location and similar designs, one would expect that if the monthly outage rate modeling made sense, there should be some correlation between their monthly outage rates. In other words, if there are causal factors that result in a definite monthly pattern of outages, it should affect all units at the station in a comparable manner. However, the exhibit shows there really is no discernable pattern in the monthly outages of these units. Indeed, there is no statistically significant correlation between the monthly outage rates of these units. It is apparent from the figure that the monthly variations about the mean amount to nothing more than "statistical noise." This strongly suggests there is no basis for the Company to apply this novel monthly outage rate modeling technique.

Exhibit ICNU/114 presents the same analysis for the Gadsby and West Valley CTs. This is a very compelling analysis because it deals with 8 identical machines, all located in the same geographic region. The graph shows that the there is no pattern in outage rates for these units. While some units may have large outages in November or February to March for example, several others had very low outage rates for those months. As discussed above, it is apparent that one or two bad months skew some of the results. The figure shows that the Company assumes West Valley Unit 4 will have an outage rate exceeding 75% every February and March, while Gadsby Unit 4 will have a 67% outage rate every November. This provides clear evidence that a few extreme months can produce very unrealistic results.

Q. DOES THE MONTHLY OUTAGE RATE MODELING INCREASE NET POWER COSTS IN GRID?

A. Yes, by the amount shown on Table 1. Given the lack of a sound engineering basis or common sense argument underlying this approach and the lack of any statistical support for it, I am forced to conclude this is little more than "numerology." It certainly appears this is a one-sided adjustment proposed by the Company for no purpose other than to increase power cost estimates. I recommend that the Commission reject the monthly modeling of outage rates and reduce net power costs by the amount shown on Table 1.

Q. DO YOU RECOMMEND THE COMMISSION ACCEPT THE THERMAL RAMPING AND STATION SERVICE ADJUSTMENTS CONTAINED IN THE GRID STUDY?

A. No. These are adjustments proposed by the Company ostensibly to better represent the operation of thermal units. They were motivated by a mistaken assumption that GRID was producing an excess of coal-fired generation.[8/] To address the ramping issue, PacifiCorp creates "phantom outages" inflating its outage rates. To address Station Service during outages, the Company adds a zero revenue sales transaction to the model.

Q. IS MODELING OF STATION SERVICE DURING OUTAGES AND THERMAL RAMPING IN THE MANNER USED BY THE COMPANY STANDARD INDUSTRY PRACTICE?

A. No. Based on my more than twenty-five years experience in working with various production cost models, this approach is extremely unusual and contrary to standard industry practice. NERC publishes a standard formula for computation of forced outage rates, and the approach proposed by the Company is inconsistent with the NERC formula.

Q. ARE YOU AWARE OF ANY INSTANCE WHERE A UTILITY PROPOSED TO INCLUDE ENERGY LOST DUE TO RAMPING IN THE OUTAGE RATES USED IN A POWER COST MODEL?

A. PacifiCorp made this similar proposal in its last Oregon, Utah and Washington rate cases. The power cost issues in those cases were settled. There is only one other case that I am aware of. In Docket No. UE 139, PGE proposed a similar modification to outage rates for the Colstrip plant to solve a similar assumed

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[8/] Re PacifiCorp, OPUC Docket No. UE 170, PPL/604, Widmer/2-3.

problem of generation from its model exceeding actual ("lost generation"). In that case, the Commission flatly rejected the PGE proposal:

> ICNU disapproves of PGE's calculations in modeling planned outages for the Colstrip plant. ICNU notes that the [NERC] has promulgated a standard equation to estimate the forced outage rate of a particular plant. In estimating the forced outage rate for Colstrip, however, PGE modified NERC's standard equation by substituting the plant's capacity factor (CF) for its equivalent availability factor (EAF). ICNU contends that PGE's deviation from standard industry practice is unjustified and arbitrarily inflates PGE's net variable power cost estimate by $1.5 million.
>
> PGE explains it made the adjustment because it obtains less energy from Colstrip than one should expect from the plant's EAF. PGE highlights that it has normally received 1 to 4 percent less generation—based on the plant's CF—than would be expected—given the plant's EAF. To account for this, PGE assigns the "missing generation" to unplanned outages. PGE has not identified any specific reason why the generation at Colstrip has fallen short of potential levels, but speculates that up or down ramping periods, generation variances including minor forced derations, or transmission pathway deratings may be responsible.
>
> * * *
>
> While it appears that an aberration exists in PGE's system that prevents the company from obtaining expected generation levels from the Colstrip plant, we are not convinced that creating "phantom outages" is the appropriate solution. First, PGE's proposed adjustment violates standard industry practice and is contrary to the company's own forecasting methods that it uses for other plants. Second, PGE's adjustment fails to account for the fact that a plant's CF, by definition, will never exceed its EAF, even those that run continuously.
>
> We are also troubled by PGE's decision to make this adjustment despite the fact that it is unable to identify the source of the generation shortfall or to quantify its effect. If the loss of energy from Colstrip is due to minor forced derations as PGE speculates, the company should be able to modify Monet to capture these derations.
>
> For these reasons, we disagree with PGE's adjustment to a standard industry equation used to compute forced outage rates when outages have nothing to do with the alleged problem.

OPUC Docket No. UE 139, Order No. 02-772 at 23-24 (internal footnotes omitted).

Q. ARE YOU AWARE OF ANY CASE WHERE A COMPANY HAS MODELED STATION SERVICE DURING OUTAGES AS A ZERO REVENUE SALES TRANSACTION?

A. I cannot recall a single case where this has been done. This approach is clearly far outside of standard industry practice and should also be rejected.

Q. EXPLAIN THE GRID COMPARISON OF ACTUAL TO PROJECTED COAL-FIRED GENERATION.

A. This is shown on Table 2, below. This presents the actual coal-fired generation for the four-year period ended September 30, 2005, taken directly from the hourly generator logs.[9/] This exhibit demonstrates that the coal-fired generation in GRID is substantially less than the actual generation for the same units for the four-year period used to estimate outage rates. As a result, the station service and ramping adjustments are simply unwarranted.

Table 2
Comparison of Actual to GRID Coal Generation

Case	MWh	% Change
4-Year Average Actual	**45,803,132**	
Original Filing	**45,092,038**	**-1.6%**
TAM Update Step 15	**44,866,957**	**-2.0%**

9/ These are the same logs used by the Company to develop its thermal ramping and station service adjustments. The figures in the exhibit already reflect the generation lost due to station service and ramping.

Q. ARE YOU DENYING THAT RAMPING AND STATION SERVICE ABSORB SOME OF THE AVAILABLE COAL-FIRED GENERATION?

A. No. While many production cost models simulate ramping, they do not do so using adjustments to the outage rates. One of the advantages of an hourly model is that it can model ramping and station service in a realistic manner. However, GRID does not take advantage of these capabilities. Because GRID does not actually model outages in a realistic manner (i.e., it uses deration instead of Monte Carlo or some other probabilistic technique), the Company cannot model ramping in a proper manner. In the end, there is no reason to make the model worse by making unwarranted adjustments to the input data to model phantom outages and fictitious sales to account for ramping and station service.

<u>Stochastic Price Modeling</u>

Q. DOES GRID MODEL STOCHASTIC PRICE INPUT VARIATIONS?

A. No. GRID assumes that the prices for fuel inputs are fixed. Though prices may vary throughout the year, there is only a single point price forecast recognized in the model.

Q. IS THIS REALISTIC?

A. No. There is ample reason to believe that prices will deviate from the forecast as events unfold. However, it is really impossible to determine by how much. As a result, one should view prices as a stochastic variable, with the current forecast being no more than the midpoint of the probability distribution.

To deal with the problem of price uncertainty, a variety of techniques are available. One approach would be to run GRID with multiple price forecasts, thus simulating system operation under differing scenarios, much as multiple water years have been modeled in the past. The problem with that approach is that it would require substantial modification to the model and would likely take far too long to perform all the runs. A better solution would be development of a pure stochastic modeling process within GRID. However, this would be an even more complex undertaking.

Q. ARE THERE ANY STEPS BEING TAKEN TO DEAL WITH THIS ISSUE?

A. Yes. For some months, OPUC Staff has advocated development of a form of stochastic modeling for both PacifiCorp and PGE. Various workshops and analyses have been conducted, but as yet, there has been no substantial progress in reformulating the power cost models.

Q. BASED ON YOUR EXPERIENCE, WHAT ARE THE MOST LIKELY OUTCOMES OF DEVELOPMENT OF MODELS THAT CAN SIMULATE STOCHASTIC PRICE VARIATIONS?

A. Such models would enable one to quantify certain benefits that are not captured in models like GRID. Probably the most important feature would be the ability to capture some of the benefits of marginal plants that are not currently reflected in the existing models.

Q. DESCRIBE THESE BENEFITS.

A. There are two types of benefits. First, one could capture the value of unused generation from gas-fired plants. Under a point price forecast, a power plant is either "in the money" or "out of the money." However, due to the dispersion in future price forecasts, it is likely that in some situations a plant will be in the money even though it might not be under a point price forecast.

Conversely, there is a benefit of off-loading gas fired units if market prices drop below forecast. In that case, lower cost purchased power would be available.

Q. CAN YOU PROVIDE AN EXAMPLE THAT ILLUSTRATES THESE BENEFITS?

A. Assume the Currant Creek plant has a variable operating cost of $50/MWh, and the market price forecast for power is just slightly above $50/MWh. In that case, GRID would not dispatch the unit, and it would generate no energy. In that mode, it would provide no benefits to ratepayers because the "spread" between power prices and Currant Creek's generating cost is slightly negative.

Now, we obviously recognize that the forecast is likely to be wrong. In all likelihood, gas prices will be different from expectations and/or power prices will be as well. In one scenario of market gas and power prices, we might find the spread between Currant Creek's operating cost and market prices is a positive $5/MWh, but equally likely might be a case where Currant Creek costs $5/MWh more than a market purchase.

The interesting thing is that in either outcome, there are opportunities to save money as compared to the mid-point forecast (which has a spread slightly less than zero). In the former case (positive $5/MWh spread), the Company should operate the facility and make sales. In the latter case, the Company should shut it down and make purchases. Either situation could provide savings, and the expected value of these benefits is called the "extrinsic value" of the resource. By focusing only on the mid-point forecast, as is the case in GRID, the extrinsic value is ignored, resulting in understatement of the benefits available from the plant and overstating power costs.

A primary benefit of the stochastic price analysis is that it would enable one to quantify the savings or costs when prices turn out differently from the forecast.

Q. HAVE YOU DEVELOPED AN ANALYSIS TO COMPUTE THE EXTRINSIC VALUE OF RESOURCES?

A. Yes. Exhibit ICNU/115 provides an example calculation showing how the extrinsic value of resources is developed. The methodology used historical spreads for Palo Verde market electric and gas prices based on Intercontinental Exchange ("ICE") day ahead prices for the period June 2002 to June 2006. Spreads are computed for each resource using its specific heat rate. From this data I developed monthly probability distributions with a mean spread based on the gas and power prices used in GRID. I then computed the probability (and savings) from off-loading units as well as from making additional sales. Results from the analysis are shown on Table 1.

Q. YOUR ANALYSIS DOES NOT INCLUDE COAL OR HYDRO PLANTS. PLEASE EXPLAIN.

A. For plants with very large spreads, whether positive or negative, the expected value of savings will be zero. The reason is that a coal plant with, for example, a spread of -$30/MWh and a standard deviation of the spread of $5/MWh would require a very extreme event before the unit would be "out of the money."[10/] In such cases, the expected value of the difference between the spread in the probability distribution and the PacifiCorp spread is zero, resulting in no additional savings. Example calculations provided in my workpapers show

[10/] In this case, it would take a price movement 6 standard deviations from the mean, which is a highly unlikely event.

scenarios where the spreads are very large (both positive and negative) resulting in no extrinsic value. This confirms the reasonableness of the method employed. It also illustrates that to capture the benefits of stochastic price modeling, it is not necessary to model all plants on the system. Only the "marginal" plants are likely to have spreads close enough to zero to make this kind of analysis necessary or useful.

Q. IS THERE ANY EVIDENCE TO DEMONSTRATE YOUR FIGURES ARE REASONABLE?

A. Yes. My results for West Valley for 2007 are only 50% of those the Company computed itself for West Valley in UE 134. Recall, that PacifiCorp used the extrinsic value analysis of part of its justification for executing the West Valley lease.

Q. YOUR METHODOLOGY MIGHT BE CRITICIZED ON THE BASIS THAT IT ONLY TREATS GAS AND MARKET PRICES AS STOCHASTIC VARIABLES, WHILE ALL OTHER VARIABLES ARE DETERMINISTIC. PLEASE COMMENT.

A. One could consider including a host of stochastic variables: loads, outage rates, coal prices, hydro generation, along with gas and power prices. However, in at least some of these cases, it is unlikely the expected value of the power cost distribution will change. For example, coal prices are not known perfectly in advance, nor are outage rates for coal-fired power plants. It is unlikely that such variables will be responsible for a systematic understatement or overstatement of power costs. Coal price and outage rates for individual plants are unlikely to have a systematic effect on market prices. As a result, there is no reason to believe that inclusion of such variables in a stochastic analysis would change the expected value of power costs.

Certainly, it is likely that load and hydro conditions could effect market prices, though probably not as much as gas prices. However, loads will be unlikely to have a substantial impact unless all utilities in a given market experience load variations moving in the same direction. There is some debate as to the impact of hydro variations on market prices as well. By using historical data over a four-year period, certainly some variations in load and hydro conditions have been captured in the price spreads used in my model. In the end, models improve when the capability to improve them exists. By adopting a stochastic price adjustment, the Commission could well provide the impetus for the utilities to further improve their models.

Q. WHAT IS YOUR RECOMMENDATION?

A. The Commission should adopt my proposed stochastic price modeling. While it would always be possible to improve any model, I believe this approach is reasonable. Further, PacifiCorp has used extrinsic value analysis in making its resource selection decisions for a variety of resources (notably West Valley, as discussed above) and certain power contracts. If utilities are going to reflect extrinsic value in the resource selection process, then it must be reflected in the rate treatment as well.

Other Power Cost Adjustments

Q. EXPLAIN YOUR PROPOSED MODIFICATIONS TO THE CHOLLA 4 AND DAVE JOHNSON UNIT 3 DATA INPUTS.

A. I recommend reversing two input changes made by the Company – a 10 MW capacity decrease in the maximum capacity for Dave Johnson Unit 3 ("DJ-3"), from 230 to 220 MW, and an increase in the minimum capacity of Cholla 4 from 150 MW to 250 MW. In both cases, these changes amount to a reversal of data changes made by the Company in this case as compared to prior cases. Review of hourly generator logs demonstrate the Company's changes are not warranted.

Q. HOW DID YOU TEST THE REASONABLENESS OF THE DJ-3 CAPACITY?

A. I reviewed the hourly logs for DJ-3 for the four-year period ended December 31, 2005. I found that there were more than 7600 hours when the unit capacity exceeded 220 MW. In 2005 alone, there were nearly 1200 hours when the capacity exceeded 220 MW. Consequently, I see no basis for this 10 MW reduction in capacity now being proposed by the Company.

Q. EXPLAIN THE CHANGE TO THE CHOLLA 4 MINIMUM CAPACITY.

A. In this case, the Company changed the minimum capacity of Cholla 4 from 150 to 250 MW due to a sodium depletion problem that can result in the minimum loading for Cholla 4 increasing from 95 MW[11/] to 250 MW in a period of sixty days following an outage. The sodium depletion problem clears up during outages and the minimum can be reset back to its lower level.

[11/] Though the physical minimum is 95 MW, transmission considerations require it to operate at 150 MW or more.

The problem with the PacifiCorp input assumption is that it assumes the "worst case scenario" occurs 100% of the time and ignores the frequency of outages at the unit. In reality, Cholla has frequent enough outages that the minimum gets reset quite often. This implies 150 MW is a much more typical minimum loading level. Further, my review of the generator logs reveals that in actual practice, the unit seldom operates in the 250 MW range. In fact, the unit logs show no basis for assuming any change to the minimum capacity for the unit. Again, this data change is not well supported and should be rejected.

Q. DO YOU AGREE WITH PACIFICORP'S MODELING OF THE FOOTE CREEK WIND PROJECT?

A. No. I am concerned that the Company has understated the generation available from this resource. Since commencement of operation in October 2001, the project has averaged 104,137 MWh per year. In GRID, the Company only forecasts 87,585 MWh for the projected period. While four years is a relatively short period of historical data, it provides the only actual information upon which to base our forecast. As a result, I recommend increasing the output of Foote Creek to match its historical generation. This adjustment reduces power costs by the amount shown in Table 1.

Q. DO YOU AGREE WITH PACIFICORP'S MODELING OF THE GP CAMAS COGENERATION PROJECT?

A. No. The Company has overstated the generation purchased from this project compared to recent trends in the actual data. It is apparent that the generation from this project has declined steadily for the past several years. Because this reduction appears to be continuing, I trended its generation for the four-year period ending February 2006 to estimate its output in 2007. This adjustment reduces net power costs by the amount shown in Table 1.

Q. IS THE MODELING OF THE COOL KEEPER DSM PROGRAM REALISTIC?

A. It appears the Company has understated the benefits of this resource. The Company only includes this resource from July 16 to August 7. However, the tariff allows interruptions between June 1 and August 31. Further, the Company only modeled 45 MW of capacity, while recent data shows substantially more capacity is already available, and that customer participation is growing rapidly. Correcting these inputs reduces net power costs by the amount shown in Table 1.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues.	)

ICNU/101

RANDALL J. FALKENBERG QUALIFICATIONS

June 30, 2006

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

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

analysts at several 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	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	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 Public	Georgia Power Co.	Cancellation of nuclear plant.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Service Commission Staff		
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	9437/ 613	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	3799-U	GA	Georgia Public Service Commission	United Cities Gas Co.	Weather normalization of gas sales and revenues.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Staff		
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.

Expert Testimony Appearances
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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.

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 Power Users Group	Tampa Electric Co.	Polk County Power Plant Rate Treatment Issues.
3/97	R-973877	PA	PAIEUG.	PECO Energy	Stranded Costs & Market

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
					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

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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 Plant	CCS	PacifiCorp	Certification of Peaking
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.
6/04	UE-161	OR	ICNU	Portland General	Power Cost Modeling
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
02/05	UE-165	OP	ICNU	Portland General	Hydro Adjustment Clause
05/05	UE-170	OR	ICNU	PacifiCorp	Power Cost Modeling
7/05	UE-172	OR	ICNU	Portland General	Power Cost Modeling
08/05	UE-173	OR	ICNU	PacifiCorp	Power Cost Adjustment
8/05	UE-050482	WA	ICNU	Avista	Power Cost modeling, Energy Recovery Mechanism
8/05	31056	TX	OPC	AEP Texas Central	Stranded cost true-up.
11/05	UE-05684	WA	ICNU	PacifiCorp	Power Cost modeling, Jurisdictional Allocation, PCA
2/06	05-116-U	AR	AEEC	Entergy Arkansas	Fuel Cost Recovery
4/06	UE-060181	WA	ICNU	Avista	Energy Cost Recovery Mechanism
5/06	22403-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
6/06	UM 1234	OR	ICNU	Portland General	Deferral of outage costs

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues.	)

ICNU/102

SHORT-TERM FIRM SALES CONTRACTS

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

June 30, 2006

CONFIDENTIAL

INFORMATION

OMITTED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
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Company's Oregon Annual Revenues.	)

ICNU/103

COMPARISON OF PALO VERDE AND

MID COLUMBIA PURCHASES AND SALES

June 30, 2006

Exhibit ICNU/103
Comparison of Palo Verde and Mid Columbia Purchases and Sales

GRID 2007 Test Year Results:

Mid Columbia	gWh	$/mWh
Balancing Purchase	3,551	72.33
Balancing Sales	(144)	50.64
STF Purchases	1,070	61.41
STF Sales	(3,945)	50.64
Palo Verde		
Balancing Purchase	3,248	73.55
Balancing Sales	(45)	89.79
STF Purchases	486	67.88
STF Sales	(4,554)	61.27

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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ICNU/104

WEST VALLEY 1 CAPACITY DURATION CURVE

June 30, 2006

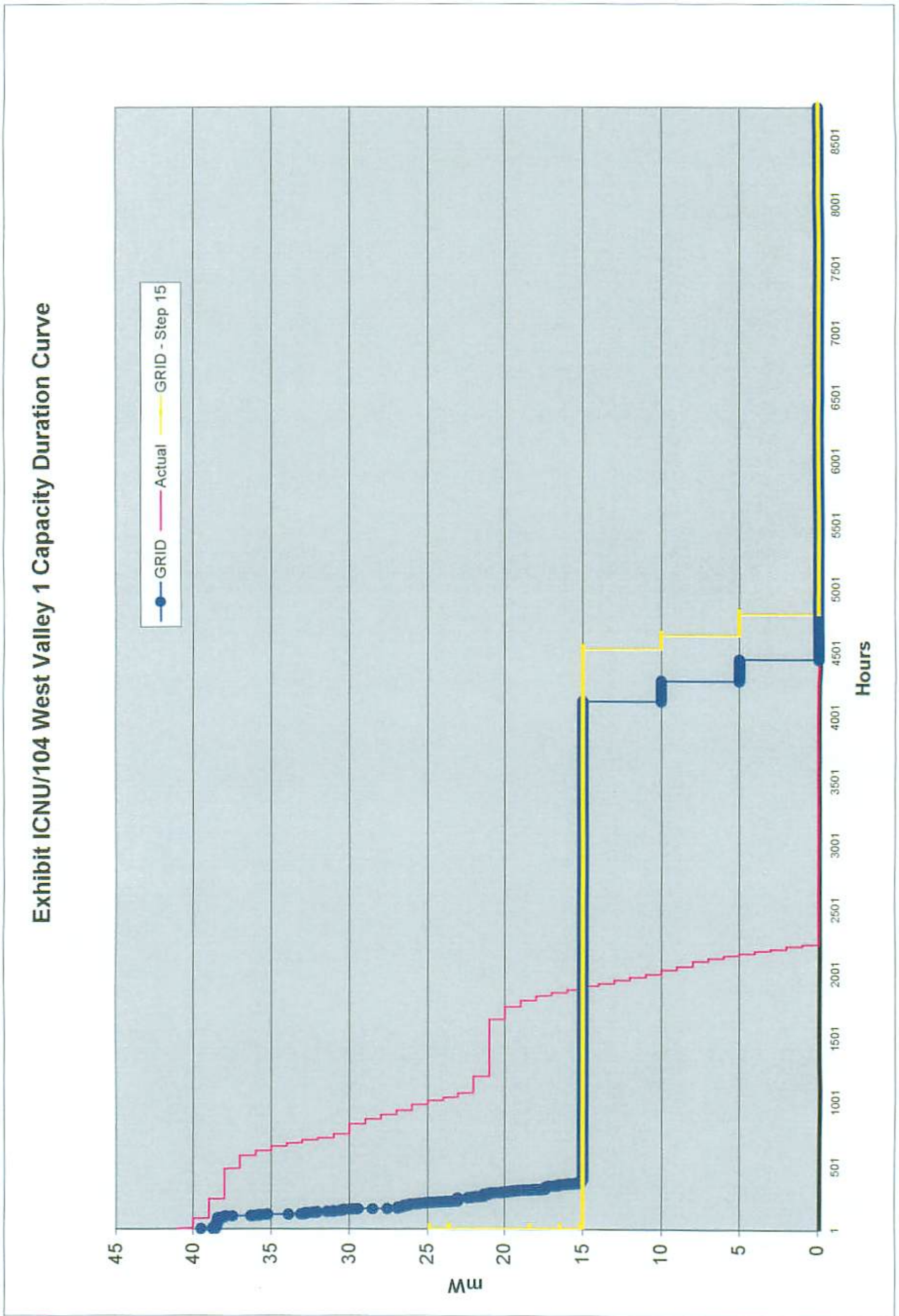
Exhibit ICNU/104 West Valley 1 Capacity Duration Curve
GRID
Actual
GRID - Step 15
mW
Hours
0
5
10
15
20
25
30
35
40
45
1
501
1001
1501
2001
2501
3001
3501
4001
4501
5001
5501
6001
6501
7001
7501
8001
8501

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

In the Matter of	)
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ICNU/105

STATISTICAL COMPARISON OF CT DISPATCH - ACTUAL VS. GRID

June 30, 2006

Exhibit ICNU/105
Statistical Comparison of CT Dispatch - Actual vs. GRID

Actual	**WV-1**	**WV-2**	**WV-3**	**WV-4**	**WV-5**	**GAD-4**	**GAD-5**	**GAD-6**
Mean	24.7	24.6	25.7	26.0	26.7	25.3	23.9	25.0
St Dev	10.4	10.4	10.8	10.9	11.4	10.0	9.9	10.4
Hours Operating	2694	2773	3084	2754	2535	2628	2234	1949
Hours at Minimum	64	59	55	57	34	45	42	46
GRID Update Step 15								
Mean	14.5	14.5	15.5	16.3	17.4	13.8	13.8	14.1
St Dev	2.0	2.5	4.0	6.8	7.1	3.1	3.1	2.7
Hours Operating	4796	4590	4509	3972	4417	3212	2670	2640
Hours at Minimum	4515	4128	3949	2964	3345	2761	2304	2356

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
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Company's Oregon Annual Revenues.	)

ICNU/106

STATISTICAL COMPARISON OF CT DISPATCH - ACTUAL VS. GRID

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

June 30, 2006

CONFIDENTIAL

INFORMATION

OMITTED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

In the Matter of	)
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PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
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ICNU/107

PACIFICORP RESPONSE TO ICNU DATA REQUEST NO. 1.19

June 30, 2006

UE-179/PacifiCorp
March 24, 2006
ICNU 1st Set Data Request 1.19

ICNU Data Request 1.19

Please explain the Company's choice of hydro levels (i.e., 25-50-75, median, 5% to 95%) used in this case. To the extent that this differs from hydro levels assumed in Docket No. UE 170, please explain how and why.

1st Replacement Response to ICNU Data Request 1.19

The Company used exceedence levels wet (25), median (50) and dry (75) in this filing.

There are several reasons for using three exceedence levels versus the nineteen exceedence levels used in prior filings.

- The Company agrees with intervenors' position in this and other jurisdictions' prior rate cases, that nineteen exceedence levels placed too much emphasis on the tails which resulted in a slightly higher level of net power cost.
- Internally the Company uses three exceedence levels (wet, median, dry) in its planning activities. Due to the issue with the 19 exceedence levels, the Company adopted the approach used for planning activities.
- There is a significant reduction in model run time using three exceedence levels versus nineteen exceedence levels.

It should be noted that the use of 3 exceedence levels versus 19 resulted in a small decrease in hydro generation.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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ICNU/108

COMPARISON OF OUTAGE RATES UE 111 AND UE 179

June 30, 2006

Exhibit ICNU/108
Comparison of Outage Rates UE 111 and UE 179

	===========2006 Rate Case=========				1999 Case	=Avg Capacity on Outage=	
	Unit ID	Current Rated Capacity	Outage Rate	PacifiCorp Share	Outage Rate	2003 Case	1999 Case
1	CHO-4	380	16.89%	100.0%	6.67%	64.2	25.3
2	COL-3	740	8.39%	10.0%	7.17%	6.2	5.3
3	COL-4	740	9.59%	10.0%	9.57%	7.1	7.1
4	CRB-1	70	6.08%	100.0%	7.51%	4.2	5.2
5	CRB-2	105	4.38%	100.0%	6.33%	4.6	6.6
6	CRG-1	428	4.08%	19.3%	2.40%	3.4	2.0
7	CRG-2	428	5.94%	19.3%	4.23%	4.9	3.5
8	DJ-1	106	4.79%	100.0%	4.93%	5.1	5.2
9	DJ-2	106	10.76%	100.0%	4.31%	11.4	4.6
10	DJ-3	223	12.37%	100.0%	13.62%	27.6	30.4
11	DJ-4	330	6.08%	100.0%	9.66%	20.1	31.9
12	HDN-1	184	3.03%	24.5%	6.43%	1.4	2.9
13	HDN-2	262	12.51%	12.6%	6.98%	4.1	2.3
14	HTG-1	440	11.08%	100.0%	10.22%	48.7	45.0
15	HTG-2	455	13.27%	100.0%	9.47%	60.4	43.1
16	HTR-1	427	11.16%	93.8%	8.97%	44.7	35.9
17	HTR-2	430	10.70%	60.3%	6.23%	27.7	16.2
18	HTR-3	460	13.59%	100.0%	6.35%	62.5	29.2
19	JB-1	530	14.85%	66.7%	7.35%	52.5	26.0
20	JB-2	530	14.95%	66.7%	6.57%	52.8	23.2
21	JB-3	530	15.94%	66.7%	8.93%	56.3	31.6
22	JB-4	526	8.20%	66.7%	8.06%	28.7	28.2
23	NTN-1	160	9.24%	100.0%	1.79%	14.8	2.9
24	NTN-2	210	10.39%	100.0%	3.90%	21.8	8.2
25	NTN-3	330	5.89%	100.0%	10.96%	19.5	36.2
26	WYO-1	335	5.89%	80.0%	5.05%	15.8	13.5

Average	9.62%	7.06%	670.5	471.5
Change	36.1%			
mW Wtd.	10.98%	7.72%		
Change	42.22%		42%	
Units with Increasing outage rates		19		
Total Number of Units		26		
Percent		73%		

Increase in Outage Capacity - mW	199.1
Savings per mW of added coal generation	370,064
Test Year Cost	$73,664,970
Oregon Allocation	26.628%
Oregon Cost	$19,615,508

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

In the Matter of	)
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	)
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ICNU/109

COMPARISON OF PACIFICORP COAL EFOR TO NERC PEER GROUP

June 30, 2006

Exhibit ICNU/109
Comparison of PacifiCorp Coal EFOR to NERC Peer Group

	Unit	WD	WE	Avg.	Capacity	NERC	GRID MW	Inc/Dec. Outage MW
1	CHO-4	9.95%	12.23%	10.71%	380	9.26%	380	5.53
2	COL-3	16.22%	18.21%	16.89%	740	8.56%	74	6.16
3	COL-4	7.93%	9.31%	8.39%	740	8.56%	74	-0.13
4	CRB-1	9.11%	10.54%	9.59%	70	9.65%	70	-0.05
5	CRB-2	5.05%	8.14%	6.08%	105	8.65%	105	-2.70
6	CRG-1	4.01%	5.10%	4.38%	428	9.57%	83	-4.29
7	CRG-2	3.61%	5.02%	4.08%	428	9.57%	83	-4.53
8	DJ-1	5.86%	6.11%	5.94%	106	8.65%	106	-2.87
9	DJ-2	4.73%	4.90%	4.79%	106	8.65%	106	-4.10
10	DJ-3	9.85%	12.58%	10.76%	230	7.98%	230	6.39
11	DJ-4	11.24%	14.62%	12.37%	330	9.26%	330	10.27
12	HDN-1	4.90%	8.44%	6.08%	184	8.65%	45	-1.16
13	HDN-2	2.56%	3.97%	3.03%	262	7.98%	33	-1.63
14	HTG-1	10.90%	15.73%	12.51%	440	9.57%	440	12.93
15	HTG-2	10.70%	11.83%	11.08%	455	9.57%	455	6.84
16	HTR-1	12.78%	14.26%	13.27%	430	9.57%	403	14.92
17	HTR-2	10.06%	13.37%	11.16%	430	9.57%	259	4.12
18	HTR-3	10.67%	10.75%	10.70%	460	9.57%	460	5.18
19	JB-1	13.21%	14.35%	13.59%	530	9.57%	353	14.18
20	JB-2	14.04%	16.48%	14.85%	530	9.57%	353	18.66
21	JB-3	14.53%	15.78%	14.95%	530	9.57%	353	18.99
22	JB-4	15.60%	16.63%	15.94%	530	9.57%	353	22.51
23	NTN-1	7.94%	8.70%	8.20%	160	8.65%	160	-0.73
24	NTN-2	8.32%	11.08%	9.24%	210	7.98%	210	2.64
25	NTN-3	9.58%	12.00%	10.39%	330	9.26%	330	3.73
26	WYO-1	5.75%	6.18%	5.89%	335	9.26%	268	-9.02
			Average	9.80%		9.09%	6,117	122
			Wtd Avg	**11.27%**		**9.28%**		

Added mW on Outage	12184.5%
Savings per mW of added coal generation	370,064
Test Year Cost	$45,090,335
Oregon Allocation	26.628%
Oregon Cost	$12,006,655

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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ICNU/110

NERC ANNUAL UNIT PERFORMANCE STATISTICS

June 30, 2006

ICNU/110
Falkenberg/1

Date-06/03/02

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

FOSSIL Coal Primary All Sizes 1996-2000 Data

1996-2000
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	NCF	SF	NOF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	SR	ART	-
1996	30.32	63.75	78.37	81.34	86.76	84.15	4.62	7.00	6.57	9.16	3.80	97.86	349.28	-
1997	31.25	65.78	80.28	81.94	87.25	84.62	4.68	7.02	6.66	8.67	3.94	97.16	419.35	-
1998	32.21	67.78	81.54	83.12	87.22	84.37	4.70	7.23	6.91	8.65	4.02	98.15	447.56	-
1999	33.19	67.63	80.89	83.61	86.01	83.32	4.85	7.03	6.75	9.69	4.12	97.22	431.53	-
2000	33.80	72.38	84.26	85.90	87.25	84.67	4.35	6.17	6.02	8.85	3.83	98.08	499.42	-
1996-00		67.43	81.02	83.23	86.89	84.22	4.64	6.90	6.58	9.01	3.94	97.67	423.66	-

		1996	1997	1998	1999	2000	1996-00
Unit-Years	:	868	871	864	857	800	4,259
Maximum Capacity (MW)	GROSS:	332	332	340	341	346	338
	NET:	315	316	317	317	326	318
Dependable Capacity (MW)	GROSS:	330	331	339	339	344	337
	NET:	314	315	316	316	324	317
Actual Generation (MWh)	GROSS:	1,875,399	1,934,983	2,027,378	2,023,088	2,217,314	2,012,348
	NET:	1,764,001	1,820,990	1,882,089	1,877,980	2,072,580	1,880,500
Attempted Unit Starts	:	20.14	17.26	16.26	16.89	15.11	17.17
Actual Unit Starts	:	19.71	16.77	15.96	16.42	14.82	16.77
Service Hours	:	6,884.31	7,032.58	7,143.04	7,085.65	7,401.39	7,104.74
Reserve Shutdown Hours	:	736.15	610.10	497.23	442.42	262.17	513.79
Number of Occurrences	:	10.49	7.24	6.24	6.21	4.50	6.97
Pumping Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Synchronous Condensing Hours	:	0.39	0.00	0.00	5.74	0.00	1.23
TOTAL AVAILABLE HOURS	:	7,620.92	7,642.77	7,640.32	7,533.88	7,663.67	7,619.84
Forced Outage Hours	:	333.76	345.26	352.29	361.17	336.36	345.87
Number of Occurrences	:	9.51	9.05	9.38	9.44	8.91	9.26
Planned Outages:							
Planned Outage Hours	:	595.13	571.73	572.76	627.00	597.48	592.67
Number of Occurrences	:	1.15	1.15	1.25	1.26	1.31	1.22
Planned Outage Ext. Hours	:	11.63	12.48	9.88	7.86	7.61	9.93
Number of Occurrences	:	0.05	0.05	0.06	0.06	0.06	0.05
Maintenance Outages:							
Maintenance Outage Hours	:	196.40	174.58	171.91	212.15	171.02	185.38

Date-10/13/05

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

FOSSIL Coal Primary All MW Sizes 2000-2004 Data

2000-2004
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	NCF	SF	NOF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	SR	ART	
2000	33.93	72.34	84.24	84.39	87.45	84.80	4.32	6.11	5.95	8.75	3.80	98.16	494.95	
2001	35.17	69.94	81.66	83.35	87.32	84.68	4.59	6.35	6.09	8.75	3.93	98.15	482.05	
2002	35.98	71.36	82.76	83.80	87.23	84.38	4.97	6.97	6.71	8.45	4.33	97.39	380.56	
2003	37.02	73.04	84.16	85.17	87.66	84.91	4.60	6.54	6.37	8.29	4.06	97.01	567.09	
2004	37.89	72.98	83.34	85.27	88.34	85.71	4.33	6.16	5.94	7.89	3.77	96.18	558.34	
2000-04		71.95	83.24	84.41	87.60	84.90	4.56	6.43	6.21	8.43	3.98	97.40	486.31	-

		2000	2001	2002	2003	2004	2000-04
Unit-Years	:	831.83	799.92	834.33	797.92	828.33	4,092.33
Maximum Capacity (MW)	GROSS:	340	330	335	336	339	336
	NET:	320	313	317	318	321	318
Dependable Capacity (MW)	GROSS:	338	329	333	335	337	335
	NET:	319	311	316	317	319	317
Actual Generation (MWh)	GROSS:	2,177,943	2,044,462	2,110,414	2,169,751	2,188,441	2,138,612
	NET:	2,035,887	1,915,703	1,983,482	2,037,557	2,055,148	2,005,935
Attempted Unit Starts	:	15.23	15.12	19.56	13.40	13.63	15.41
Actual Unit Starts	:	14.95	14.84	19.05	13.00	13.11	15.01
Service Hours	:	7,399.56	7,153.62	7,249.61	7,372.15	7,319.84	7,299.44
Reserve Shutdown Hours	:	271.89	474.74	380.01	278.84	422.36	365.40
Number of Occurrences	:	4.62	4.63	5.28	3.76	4.35	4.54
Pumping Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Synchronous Condensing Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL AVAILABLE HOURS	:	7,681.56	7,649.30	7,641.14	7,678.69	7,758.60	7,682.05
Forced Outage Hours	:	334.15	344.14	378.88	355.31	331.20	348.75
Number of Occurrences	:	8.74	8.72	9.37	9.28	8.82	8.98
Planned Outages:							
Planned Outage Hours	:	590.36	603.48	556.12	570.08	541.48	572.09
Number of Occurrences	:	3.41	7.27	2.48	6.03	4.12	4.63
Planned Outage Ext. Hours	:	5.92	14.55	11.52	8.76	5.47	9.21
Number of Occurrences	:	0.66	0.06	0.07	0.39	0.05	0.25
Maintenance Outages:							
Maintenance Outage Hours	:	171.33	146.75	170.96	146.62	144.84	156.27

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues.	)

ICNU/111

EXCERPT OF PACIFICORP RESPONSE TO ICNU DATA REQUEST NO. 6.1

(OUTAGE REPORTS)

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

June 30, 2006

CONFIDENTIAL

INFORMATION

OMITTED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues.	)

ICNU/112

PACIFICORP RESPONSE TO ICNU DATA REQUEST NO. 1.31

June 30, 2006

UE-179/PacifiCorp
March 21, 2006
ICNU 1st Set Data Request 1.31

ICNU Data Request 1.31

Please explain how PacifiCorp determines the duration and timing of Planned Outages in the GRID model studies.

Response to ICNU Data Request 1.31

The Company assigns a planned outage to each unit based on the average annual outages from the 48-month period identified in the Company's response to ICNU 1.3. Using those planned outages, the Company prepares a normalized planned outage schedule based on the parameters listed on tab "Considerations" in Attachment ICNU 1.31 on the enclosed CD.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues.	)

ICNU/113

BRIDGER OUTAGE RATES IN GRID

June 30, 2006

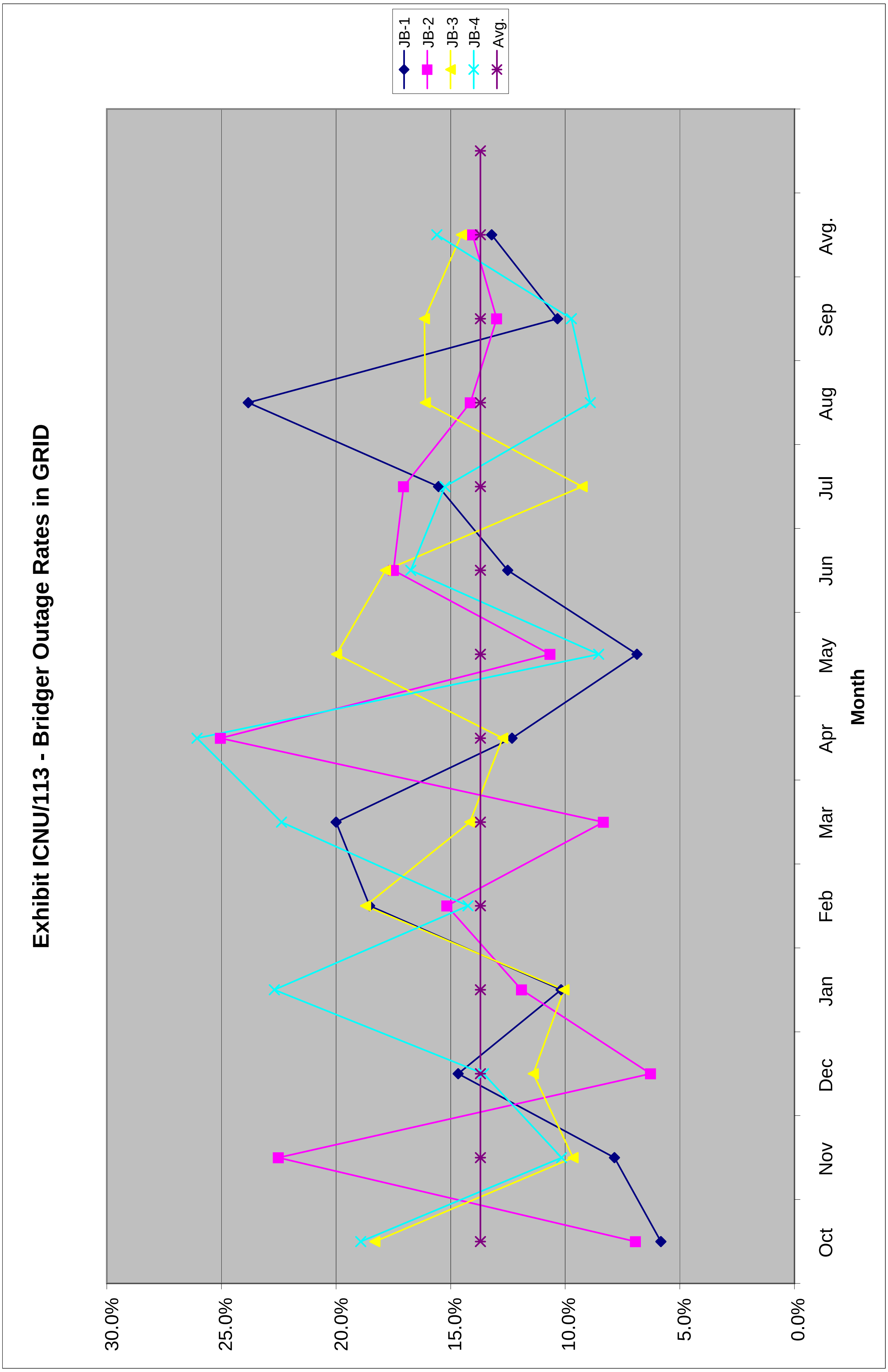
Exhibit ICNU/113 - Bridger Outage Rates in GRID
JB-1
JB-2
JB-3
JB-4
Avg.
30.0%
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
Oct
Nov
Dec
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Avg.
Month

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues.	)

ICNU/114

CT OUTAGE RATES IN GRID

June 30, 2006

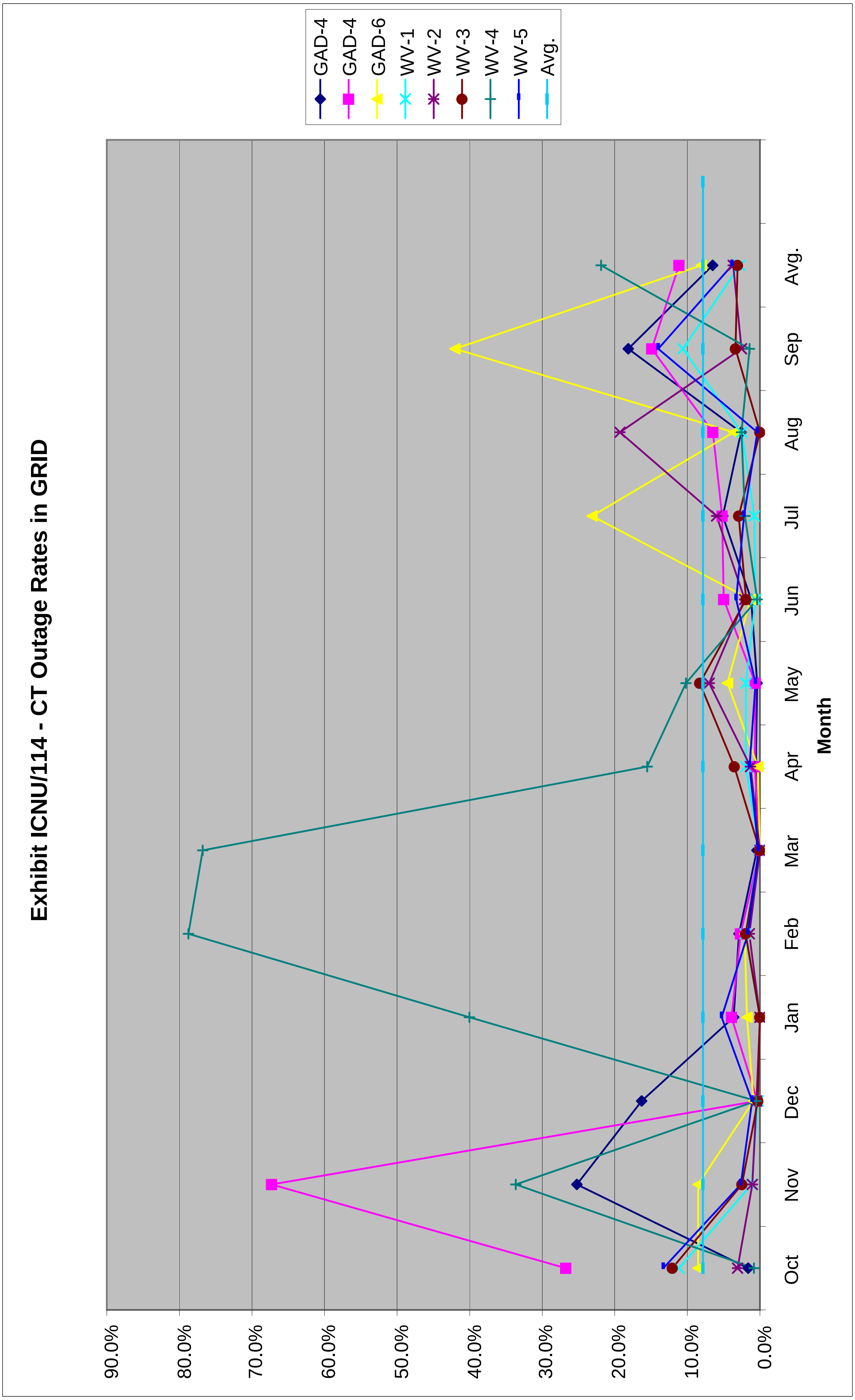
Exhibit ICNU/114 - CT Outage Rates in GRID
GAD-4
GAD-4
GAD-6
WV-1
WV-2
WV-3
WV-4
WV-5
Avg.
90.0%
80.0%
70.0%
60.0%
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
Oct
Nov
Dec
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Avg.
Month

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues.	)

ICNU/115

ILLUSTRATION OF STOCHASTIC MODELING

June 30, 2006

Exhibit ICNU/115
Illustration of Stochastic Modeling

Example 1 = Positive and Negative Spreads
Case = WV, Month = May

GRID SPREAD												
-0.34												
STDEV												
7.39	1	2	3	4	5	6	7	8	9	10	11	12
No. of St. Dev. From the Mean	-2.6	-2.5	-2.4	-2.3	-2.2	-2.1	-2	-1.9	-1.8	-1.7	-1.6	-1.5
Cumulative Prob. Of Normal Dist.	0.005	0.007	0.009	0.012	0.016	0.020	0.026	0.032	0.040	0.049	0.061	0.074
Cell Probability	0.005	0.002	0.002	0.003	0.004	0.004	0.005	0.007	0.008	0.009	0.011	0.013
$/mWh Spread	-19.55	-18.82	-18.08	-17.34	-16.60	-15.86	-15.12	-14.38	-13.64	-12.90	-12.17	-11.43
Prob. Wtd Spread	-0.105	-0.033	-0.041	-0.049	-0.059	-0.070	-0.082	-0.094	-0.108	-0.121	-0.135	-0.148
Off Loading and Sales- Stochastic Model												
Spread	-19.55	-18.82	-18.08	-17.34	-16.60	-15.86	-15.12	-14.38	-13.64	-12.90	-12.17	-11.43
mWh	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200
Spread times mWh	-1,626,970	-1,565,492	-1,504,013	-1,442,535	-1,381,056	-1,319,578	-1,258,099	-1,196,621	-1,135,142	-1,073,664	-1,012,185	-950,707
Probability Weighted Impact	-8763	-2750	-3375	-4094	-4907	-5812	-6801	-7860	-8970	-10106	-11235	-12320
Negative Spread Cases (Off Loading)*	8763	2750	3375	4094	4907	5812	6801	7860	8970	10106	11235	12320
Positive Spread Cases (Sales)	0	0	0	0	0	0	0	0	0	0	0	0
GIRD Simulation												
Spread	-19.55	-18.82	-18.08	-17.34	-16.60	-15.86	-15.12	-14.38	-13.64	-12.90	-12.17	-11.43
mWh	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200
Spread times mWh	-1,626,970	-1,565,492	-1,504,013	-1,442,535	-1,381,056	-1,319,578	-1,258,099	-1,196,621	-1,135,142	-1,073,664	-1,012,185	-950,707
Probability Assumed in GRID	0	0	0	0	0	0	0	0	0	0	0	0
Probability Weight Savings	0	0	0	0	0	0	0	0	0	0	0	0

*** - Change of Sign because savings result from lower purchased power costs**

Exhibit ICNU/115
Illustration of Stochastic Modeling

Example 1 = Positive and Negative Sp
Case = WV, Month = May

GRID SPREAD	STDEV
-0.34	7.39

	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
No. of St. Dev. From the Mean	-1.4	-1.3	-1.2	-1.1	-1	-0.9	-0.8	-0.7	-0.6	-0.5	-0.4	-0.3	-0.2	-0.1	0.00
Cumulative Prob. Of Normal Dist.	0.089	0.106	0.125	0.147	0.171	0.198	0.227	0.258	0.291	0.326	0.363	0.401	0.440	0.480	0.520
Cell Probability	0.015	0.017	0.019	0.022	0.024	0.027	0.029	0.031	0.033	0.035	0.037	0.038	0.039	0.040	0.040
$/mWh Spread	-10.69	-9.95	-9.21	-8.47	-7.73	-6.99	-6.25	-5.52	-4.78	-4.04	-3.30	-2.56	-1.82	-1.08	-0.34
Prob. Wtd Spread	-0.160	-0.171	-0.179	-0.185	-0.187	-0.186	-0.181	-0.172	-0.159	-0.142	-0.121	-0.098	-0.071	-0.043	-0.014
Off Loading and Sales- Stochastic Mo															
Spread	-10.69	-9.95	-9.21	-8.47	-7.73	-6.99	-6.25	-5.52	-4.78	-4.04	-3.30	-2.56	-1.82	-1.08	-0.34
mWh	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200
Spread times mWh	-889,228	-827,750	-766,271	-704,793	-643,314	-581,836	-520,357	-458,879	-397,400	-335,921	-274,443	-212,964	-151,486	-90,007	-28,529
Probability Weighted Impact	-13320	-14189	-14883	-15355	-15566	-15481	-15072	-14326	-13239	-11823	-10103	-8119	-5921	-3571	-1138
Negative Spread Cases (Off Loading)*	13320	14189	14883	15355	15566	15481	15072	14326	13239	11823	10103	8119	5921	3571	1138
Positive Spread Cases (Sales)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GIRD Simulation															
Spread	-10.69	-9.95	-9.21	-8.47	-7.73	-6.99	-6.25	-5.52	-4.78	-4.04	-3.30	-2.56	-1.82	-1.08	**-0.34**
mWh	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	**83200**
Spread times mWh	-889,228	-827,750	-766,271	-704,793	-643,314	-581,836	-520,357	-458,879	-397,400	-335,921	-274,443	-212,964	-151,486	-90,007	**-28,529**
Probability Assumed in GRID	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1**
Probability Weight Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**28529**

*** - Change of Sign because savings re**

Exhibit ICNU/115
Illustration of Stochastic Modeling

Example 1 = Positive and Negative Sp
Case = WV, Month = May

GRID SPREAD -0.34 / **STDEV** 7.39	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42
No. of St. Dev. From the Mean	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1	1.1	1.2	1.3	1.4	1.5
Cumulative Prob. Of Normal Dist.	0.560	0.599	0.637	0.674	0.709	0.742	0.773	0.802	0.829	0.853	0.875	0.894	0.911	0.926	0.939
Cell Probability	0.040	0.039	0.038	0.037	0.035	0.033	0.031	0.029	0.027	0.024	0.022	0.019	0.017	0.015	0.013
$/mWh Spread	0.40	1.13	1.87	2.61	3.35	4.09	4.83	5.57	6.31	7.05	7.79	8.52	9.26	10.00	10.74
Prob. Wtd Spread	0.016	0.044	0.071	0.096	0.118	0.136	0.151	0.161	0.168	0.171	0.170	0.166	0.159	0.150	0.139
Off Loading and Sales- Stochastic Mo															
Spread	0.40	1.13	1.87	2.61	3.35	4.09	4.83	5.57	6.31	7.05	7.79	8.52	9.26	10.00	10.74
mWh	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200
Spread times mWh	32,950	94,428	155,907	217,385	278,864	340,342	401,821	463,299	524,778	586,256	647,735	709,213	770,692	832,170	893,649
Probability Weighted Impact	1307	3691	5944	8003	9815	11338	12544	13419	13962	14186	14112	13774	13211	12465	11580
Negative Spread Cases (Off Loading)*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Positive Spread Cases (Sales)	1307	3691	5944	8003	9815	11338	12544	13419	13962	14186	14112	13774	13211	12465	11580
GIRD Simulation															
Spread	0.40	1.13	1.87	2.61	3.35	4.09	4.83	5.57	6.31	7.05	7.79	8.52	9.26	10.00	10.74
mWh	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200
Spread times mWh	32,950	94,428	155,907	217,385	278,864	340,342	401,821	463,299	524,778	586,256	647,735	709,213	770,692	832,170	893,649
Probability Assumed in GRID	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Probability Weight Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

*** - Change of Sign because savings re**

Exhibit ICNU/115
Illustration of Stochastic Modeling

Example 1 = Positive and Negative Sp
Case = WV, Month = May

GRID SPREAD -0.34													
STDEV 7.39	43	44	45	46	47	48	49	50	51	52	53		
No. of St. Dev. From the Mean	1.6	1.7	1.8	1.9	2	2.1	2.2	2.3	2.4	2.5	2.6		
Cumulative Prob. Of Normal Dist.	0.951	0.960	0.968	0.974	0.980	0.984	0.988	0.991	0.993	0.995	0.996		
Cell Probability	0.011	0.009	0.008	0.007	0.005	0.004	0.004	0.003	0.002	0.002	0.005	Stochastic Wtd. Price	
$/mWh Spread	11.48	12.22	12.96	13.70	14.44	15.17	15.91	16.65	17.39	18.13	18.87	Sales	Offloading
Prob. Wtd Spread	0.127	0.115	0.102	0.090	0.078	0.067	0.057	0.047	0.039	0.032	0.102	2.77	-3.11
Off Loading and Sales- Stochastic Mo													
Spread	11.48	12.22	12.96	13.70	14.44	15.17	15.91	16.65	17.39	18.13	18.87		
mWh	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200		
Spread times mWh	955,127	1,016,606	1,078,084	1,139,563	1,201,041	1,262,520	1,323,998	1,385,477	1,446,955	1,508,434	1,569,912	**Stochastic**	
Probability Weighted Impact	10601	9569	8519	7485	6493	5561	4704	3932	3247	2650	8456	**Savings**	
Negative Spread Cases (Off Loading)*	0	0	0	0	0	0	0	0	0	0	0	**259098**	**Off Loading**
Positive Spread Cases (Sales)	10601	9569	8519	7485	6493	5561	4704	3932	3247	2650	8456	**230569**	**Sales**
GIRD Simulation											Total Savings	**489668**	**Total**
Spread	11.48	12.22	12.96	13.70	14.44	15.17	15.91	16.65	17.39	18.13	18.87		
mWh	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200	83200		
Spread times mWh	955,127	1,016,606	1,078,084	1,139,563	1,201,041	1,262,520	1,323,998	1,385,477	1,446,955	1,508,434	1,569,912	**GRID**	
Probability Assumed in GRID	0	0	0	0	0	0	0	0	0	0	0	**Savings**	
Probability Weight Savings	0	0	0	0	0	0	0	0	0	0	0	**28529**	**Off Loading**
*** - Change of Sign because savings re**										**Difference from GRID**		**461139**	

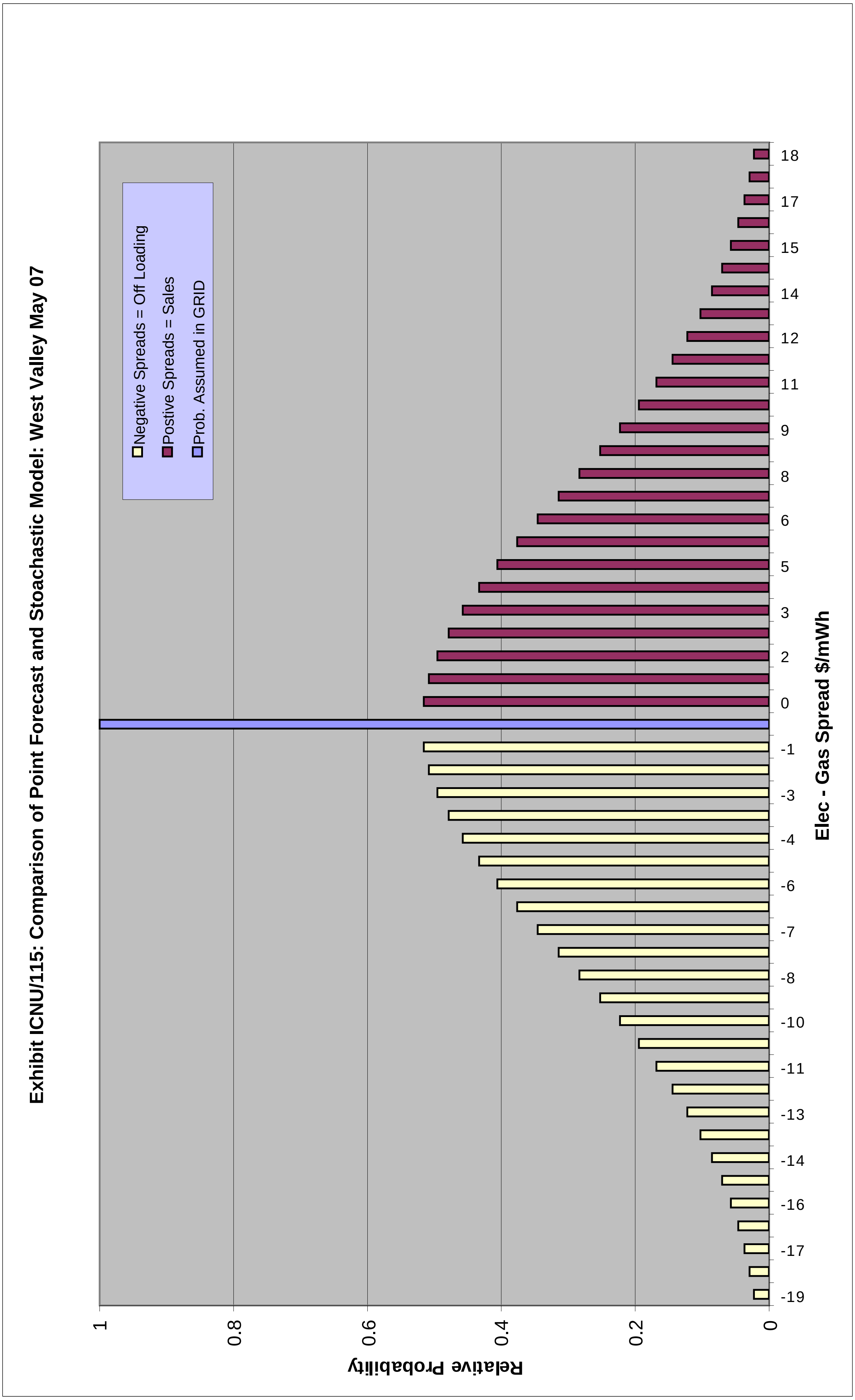
Exhibit ICNU/115: Comparison of Point Forecast and Stoachastic Model: West Valley May 07
Negative Spreads = Off Loading
Postive Spreads = Sales
Prob. Assumed in GRID
Relative Probability
1
0.8
0.6
0.4
0.2
0
Elec - Gas Spread $/mWh
-19
-17
-16
-14
-13
-11
-10
-8
-7
-6
-4
-3
-1
0
2
3
5
6
8
9
11
12
14
15
17
18

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June 30, 2006

Via Electronic and U.S. 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 PACIFIC POWER & LIGHT Request for a General Rate Increase in the Company's Oregon Annual Revenues
Docket No. UE 179

Dear Filing Center:

Enclosed please find an original and five copies of the Direct Testimony of Randall J. Falkenberg on Power Costs on behalf of the Industrial Customers of Northwest Utilities in the above-referenced docket. The confidential pages are provided in separate, sealed envelopes pursuant to the terms of the Protective Order in this proceeding.

Thank you for your assistance.

Sincerely,

/s/ Christian Griffen
Christian W. Griffen

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 Power Costs on behalf of the Industrial Customers of Northwest Utilities upon the parties on the service list by causing the same to be deposited in the U.S. Mail, postage-prepaid.

Dated at Portland, Oregon, this 30th day of June, 2006.

/s/ Christian Griffen
Christian W. Griffen

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