McDowell & Rackner PC

KATHERINE A. MCDOWELL
Direct (503) 595-3924
katherine@mcd-law.com

September 5, 2007

VIA ELECTRONIC FILING

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: Docket UE 191

Enclosed for filing in the above-referenced docket are an original and six copies of PacifiCorp's Opening Brief. A copy of this filing has been served on all parties to this proceeding as indicated on the attached certificate of service.

Very truly yours,

Katherine A. McDowell

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 191

In the Matter of PACIFICORP's 2008 Transition Adjustment Mechanism.	**PACIFICORP'S OPENING BRIEF**

I. INTRODUCTION

In this Transition Adjustment Mechanism ("TAM") filing, PacifiCorp seeks an order increasing rates to reflect PacifiCorp's net variable power costs ("NVPC") forecast for 2008 of approximately $979.5 million on a six-state, total system basis, and approximately $247.0 million on an Oregon-allocated basis. (PPL/204, Widmer/2; PPL/102, Kelly/2.) This forecast is subject to updates in November 2007 for contracts and forward prices. PacifiCorp seeks a January 1, 2008 effective date for its new TAM rates.

Measured from the correct total company NVPC baseline currently in rates—the $834.4 million 2007 TAM cap approved in the UE 179 Stipulation—the 2008 TAM currently results in a rate increase of approximately $29.6 million, or approximately 3.2 percent on an overall basis. (PPL/102, Kelly/2.) The final level of rate increase, however, will be a function of the TAM updates in November 2007.

PacifiCorp's proposal for its 2008 TAM rate increase is straightforward because it is driven by generally uncontroverted factors, such as higher coal and natural gas prices and new contract costs, and mitigated by the inclusion of the relatively low variable costs of PacifiCorp's new 525 MW Lake Side combined cycle combustion turbine facility ("CCCT"), the matching capital costs of which are not yet in rates. (PPL/200, Widmer/5.) PacifiCorp's 2008 TAM increase is further mitigated by the inclusion of new wind facilities, Goodnoe Hills and Marengo, the variable costs of which are zero. *Id.* PacifiCorp's TAM increase is relatively streamlined because PacifiCorp accepted a number of proposed adjustments in its rebuttal testimony (including two major adjustments proposed by Staff and several proposed

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

by ICNU), reducing its rate increase from approximately $36 million to $29.6 million. PacifiCorp has also worked to resolve several important policy issues raised in the case by CUB, most notably CUB's proposal to update the Embedded Cost Deferential ("ECD"), a part of PacifiCorp's Revised Protocol method of inter-jurisdictional cost allocation.

There are three primary adjustments that now remain in this case, the values for which are all stated on an Oregon allocated basis: Staff's margin adjustment of $16.2 million; ICNU's adjustment of $7.5 million changing the 2007 TAM baseline PacifiCorp used in calculating the proposed rate increase; and ICNU's adjustment of $1.5 million reducing PacifiCorp's forced outage rate to exclude certain outages. Additionally, ICNU has proposed a half-dozen smaller adjustments, totaling just over $2 million.

PacifiCorp respectfully requests approval of its full 2008 TAM increase and rejection of the remaining adjustments proposed by Staff and ICNU. PacifiCorp's TAM increase is a product of its GRID model (an hourly production dispatch model, developed at the request of Commission Staff and used in its last four rate cases); generally uncontroverted market price, fuel costs and contract inputs; and Staff and intervenor adjustments accepted by PacifiCorp.

Each of the remaining adjustments seeks to adjust the results of the GRID model to produce a lower overall TAM increase for 2008. These adjustments lack meaningful evidentiary and policy support. Additionally, these adjustments would not align PacifiCorp's power costs in rates with PacifiCorp's actual power costs. Over the last five years, PacifiCorp's power costs in rates have been *understated* by an average of approximately $62 million per year. (PPL/207,Widmer/1). Because PacifiCorp does not have a power cost adjustment mechanism ("PCAM"), these adverse results send incorrect price signals to customers and directly impact PacifiCorp's bottom line. Moreover, because the transition credit or charge for direct access is based upon PacifiCorp's NVPC in rates, the understatement of power costs in rates also results in the under-valuation of the transition credit for direct access. This, in turn, undermines the development of a viable retail competitive market in Oregon. Adoption of any of the remaining adjustments significantly increases the risk that this under-recovery and under-valuation will continue in 2008.

II. REGULATORY BACKGROUND

A. PacifiCorp's Multi-State Generation System and Cost Allocation Protocol.

PacifiCorp serves approximately 1.6 million customers in six Western states: Oregon, Utah, Wyoming, Washington, Idaho and California. As summarized in the Commission's order on PacifiCorp's last Integrated Resource Plan, "PacifiCorp owns or has interests in 71 generating plants with a net plant capability totaling 7.987 megawatts (MW). For the FY ending March 31, 2004, 68.4 percent of the Company's total energy requirements were supplied by 11 coal plants, 5.4 percent from hydroelectric plants, 0.2 percent from one wind plant and 4.1 percent from four natural gas plants and one geothermal plant. Short-term and long-term contracts and spot-market purchases supplied the remaining 22 percent of the Company's energy needs." *In re PacifiCorp 2004 Integrated Resource Plan*, Order No. 06-029 at 2 (2006). The filing in this case reflects the addition of several new generation resources since the date of this order, including new wind resources (Leaning Juniper, Goodnoe Hills and Marengo) and the 525 MW Lake Side CCCT. (PPL/200, Widmer/5; PPL/202; PPL/203.)

In 2005, the Oregon Commission approved the Revised PacifiCorp Inter-Jurisdictional Cost Allocation Protocol (Revised Protocol) to allocate PacifiCorp's costs among its six-state service territory. *In re PacifiCorp's Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol,* Order No. 05-021 (2005). Under the Revised Protocol, PacifiCorp agreed to continue to plan and operate its generation and transmission system on an integrated, six-state basis in order to achieve a least cost/least risk resource portfolio for its customers. *Id.* at 3. In

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

return, the Revised Protocol allows PacifiCorp an opportunity to recover its prudently incurred costs associated with its investment in generation resources. *Id.* at 6.

There are two aspects of the Revised Protocol which are particularly relevant to this case. First, the Revised Protocol uses Load-Based Dynamic Allocation Factors to prevent faster-growing states such as Utah from imposing unreasonable load growth costs on slower-growing states such as Oregon. *Id.* at 4. As a part of the TAM filing, PacifiCorp estimates its 2008 loads and resources and updates inter-jurisdictional state allocation factors based upon these estimates. (PPL/100, Kelly/5.) Because Oregon remains a relatively slow-growing state, Oregon's allocated share of PacifiCorp's NVPC in 2008 decreased, reducing the amount of PacifiCorp's original TAM filing in this case by approximately $9 million. *Id.*

The reduction of allocation factors between PacifiCorp's last two general rate cases, UE 170 and UE 179, is also at the heart of ICNU's "NVPC in rates" adjustment. ICNU's recalculation of the 2007 TAM amounts specified in the UE 179 Stipulation starts with higher UE 170 allocation factors, which produces a larger Oregon allocated power cost amount for the 2007 TAM and a smaller rate increase in this case. As discussed below, however, the UE 179 Stipulation expressly addressed this issue, by first calculating the 2007 TAM cap on a total company basis, then using lower, agreed-upon allocation factors from UE 179 for calculating the Oregon rate increase in the 2007 TAM. This is the baseline from which PacifiCorp calculated the NVPC increase in this case.

Second, the Revised Protocol identified a hydro endowment made up of certain hydro resources and allocated a larger share of the costs of these Regional Resources to Oregon, Washington and California through operation of the ECD Adjustment. Order No. 05-021 at Attachment A, Revised Protocol 4-5. This adjustment compares the cost of designated hydro resources to the cost of all other resources. As discussed below, CUB

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

proposed updating the Hydro Endowment ECD in this case, and PacifiCorp and CUB have agreed upon a process outside of this case to resolve this issue.

B. PacifiCorp's Power Costs in Rates.

Under the Revised Protocol, PacifiCorp's power costs in rates are determined on a total company basis and allocated to Oregon. PacifiCorp's NVPC are calculated based on projected data from PacifiCorp's hourly production dispatch model, the GRID model. (PPL/200, Widmer/7.) To forecast 2008 TAM rates, the Company updated the following model inputs: system load, wholesale sale revenues and purchase power expenses, wheeling expenses, market prices for natural gas and electricity, fuel expenses, hydro generation, thermal heat rates and thermal planned maintenance and outages. (PPL/200, Widmer/9.) As discussed below, these updates are consistent with the Commission's order approving the TAM. (PPL/100, Kelly/3.)

GRID is used to develop power costs projections for the test period which assume normal market, stream flow and weather conditions and normal thermal availability. (PPL/200, Widmer/7.) For each hour in the forecast period, the model simulates the operation of the Company's power supply under a variety of stream flow conditions and then averages this data to produce normalized results. *Id.* Following the Commission's long-standing approach, NVPC are calculated using normalized thermal plant availability, based upon a rolling four-year average for plant maintenance and outages. (PPL/204, Widmer/20.)

GRID is a deterministic hourly production dispatch model, which balances loads and resources with perfect foresight based upon market prices, load requirements, resource characteristics and transmission availability. (PPL/204, Widmer/15-16.) This results in lower volumes of short-term, system balancing transactions in the model than in actual results. *Id.* at 16. The model does, however, capture the value of PacifiCorp's system flexibility on a normalized basis by optimizing available transmission for wholesale

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

transactions and curtailing generation when lower cost market purchases are available. *Id.* at 15.

PacifiCorp has used the GRID model in its last several rates filings in Oregon. (PPL/200, Widmer/7.) The Company filed this case with an updated version of the model, GRID 6.1. (PPL/200, Widmer/8.) While the model updates improve the functionality of the model and slightly reduce PacifiCorp's NVPC, CUB nonetheless raised policy concerns in its testimony about the introduction of new versions of the GRID model in a TAM filing. (CUB/100, Jenks/4.) As discussed below, PacifiCorp has agreed to formalize a pre-filing review of any GRID model changes for future TAM filings. (PPL/102, Kelly/6-7.)

PacifiCorp developed the GRID model in response to Staff's proposal in UE 116 (PacifiCorp's general rate case for rates effective fall 2001), that PacifiCorp replace its monthly power cost model, PD/Mac, with an hourly model. (PPL/602, Pages/2-3.) While Staff originally justified its margin adjustment on the deficiencies of the PD/Mac model, Staff renewed the adjustment in rate cases PacifiCorp filed using the GRID model. (*Id.*; PPL/204, Widmer/11-12.)

In UE 170 (PacifiCorp's general rate case with a 2006 test year), PacifiCorp agreed to Staff's recommendation that it begin evaluating stochastic power cost modeling for power costs. (Staff/100, Wordley/2.) This modeling work was designed to focus on the volatility of hydro generation, electricity prices, natural gas prices, system load and forced outages, as well as correlations among these variables. *Id.* In UE 179 (PacifiCorp's general rate case with a 2007 test year), Staff opined that its margin adjustment and extrinsic value adjustments could be eliminated if the Company used stochastic modeling in place of GRID. (PPL/604, Page 11; PPL/204, Widmer/12.)

In this case, Staff recommended that PacifiCorp file a report on its analysis of stochastic modeling for power costs by September 1, 2007. (Staff/100, Wordley/2.) This is the date the Commission ordered PGE to file a similar report in its last rate case, after which

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

the Commission indicated it would open a generic docket on stochastic modeling of power costs in rates. *In re Portland General Electric Company*, Order No. 07-015, at 12, 56 (2007) ("UE 180 Order"). The order directing PGE to file a report on stochastic modeling was a part of the Commission's analysis of Staff's extrinsic value adjustment in the UE 180 Order, an adjustment the Commission rejected. *Id.* at 12. As discussed below, PacifiCorp has agreed to Staff's recommendation on stochastic modeling, with an alternative filing date. (PPL/204, Widmer/7.)

C. PacifiCorp's Transition Adjustment Mechanism.

The Transition Adjustment Mechanism is a relatively narrow, streamlined proceeding where PacifiCorp's NVPC are updated annually, subject to a prudence review. This update is used to reset rates annually and determine the direct access transition adjustment. (PPL/102, Kelly/2.) Similar to an automatic adjustment clause, the TAM updates a specific aspect of PacifiCorp's costs, net variable power costs, without consideration of PacifiCorp's overall revenues.

In the UE 180 Order, the Commission confirmed the importance of an annual update of power cost forecasts: "We believe it is important to update the forecast of power costs included in rates to account for new information, *e.g.,* on expected market prices for electricity and natural gas, and for new ... purchase power contracts." UE 180 Order at 18. The Commission also distinguished the function of an annual update and a PCAM, noting that "the mechanisms serve different purposes. The Annual Update revises the forecast of power costs, while all the PCAMs proposed in this case address the difference between forecast and actual power costs." *Id.* at 18. This distinction is especially important for PacifiCorp, which has an annual update mechanism but not a PCAM.

The usefulness of an annual update for power cost forecasts, such as that included in the TAM, has been highlighted by new or recently proposed regulatory mechanisms, such as the automatic adjustment clauses for renewable resources under SB 838 and the

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

purchase power incentive proposals pending in Docket UM 1276, both of which rely upon an annual update to power cost forecasts as a foundation. (PPL/102, Kelly/2-3.)

The history of the TAM helps to clarify its purpose and scope. PacifiCorp's TAM was developed as a result of a Commission investigation into direct access and the calculation of the transition adjustment, Docket UM 1081. Oregon's direct access law authorizes transition charges or credits that reasonably balance the interests of retail electricity consumers and utility investors. *See* ORS 757.607(2). The Commission adopted an "ongoing valuation" method for determining transition costs or benefits of a generation asset, which compares the value of the asset output at projected market prices for a defined period to an estimate of the revenue requirement of the asset for the same time period. *See* OAR 860-038-0140(1); OAR 860-038-0005(41).

Customers eligible for direct access may change service providers during an annual election period beginning on November 15. OAR 860-038-0275. Using the ongoing valuation method, utilities announce their prices and calculate their annual transition adjustment just prior to the annual direct access enrollment window in mid-November. *Id.* (requiring utilities to state their prices for the upcoming year five business days prior to November 15.) The two key inputs to this calculation are forward market prices and the generation cost of service rate. *See* OAR 860-038-0140. The more current and accurate these inputs, the more precise the transition adjustment and the lower the risk of cost-shifting. *In re PacifiCorp*, Order No. 05-1050 at 20-21 (2005) ("UE 170 Order").

In the final order in UM 1081, the Commission directed PacifiCorp to develop a permanent transition adjustment mechanism using its GRID model to ensure that "the transition adjustment will value utility resources impacted by direct access based on actual, appropriate operational responses." *In re Commission Investigation into Direct Access Issues*, Order No. 04-516 at 1-2 (2004).

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

PacifiCorp filed its proposed TAM as a part of its rate case in Docket UE 170. PacifiCorp proposed an annual power cost update to accurately measure the transition adjustment:

> PacifiCorp's proposed TAM relies on its power cost model, GRID. PacifiCorp proposes to make two GRID runs for each rate schedule, one with full Oregon load and one with a 25 MW load reduction shaped according to the rate schedule. These runs will be used to calculate the weighted market value of the energy used to serve direct access customers. The TAM then calculates the adjustment by comparing the weighted market value to the cost of service rate under the customers' specific, energy-only tariff. Included in the process is an annual power cost update to ensure that both the weighted market value and the cost of service are calculated for the same period using the same data. PacifiCorp chose to procedurally base its TAM on the RVM utilized by PGE, with the hope that it would be easier to use a model that has already been tested by the Commission. UE 170 Order at 20.

Staff supported PacifiCorp's TAM with an annual NVPC update because: (1) the TAM provided an accurate accounting of direct access impacts on PacifiCorp's system operations; and (2) the TAM resulted in transition adjustment rates that prevent unwarranted cost shifts between utility investors and direct access customers, consistent with ORS 757.607(2). *Id.* The Commission adopted Staff's rationale in approving the TAM as filed by PacifiCorp, noting that the purpose of the TAM "is to capture costs associated with direct access, and prevent unwarranted cost shifting." *Id.* at 21.

Pursuant to the UE 170 Order, the Company's TAM is filed annually in April. (PPL/100, Kelly/2.) This filing is limited to include only the following updates to PacifiCorp's NVPC: (1) forward price curve; (2) forecast loads; (3) normalized hydro generation; (4) forecast fuel prices; (5) contract updates; (6) thermal heat rates, planned outages and de-rates; (7) wheeling expenses; (8) new resource acquisitions; and (9) state allocation factors. (PPL/100, Kelly/3.) At the end of July (July 25, 2007 in this case), PacifiCorp updates this filing to reflect: (1) the current forward price curve; and (2) new contracts and/or updates for wholesale sales, purchases, fuel and wheeling expenses. (PPL/200, Widmer/6.)

After the Commission's order is issued in the TAM—the target date for which is October 19, 2007 in this case—PacifiCorp makes a final set of updates to its power costs for changes in market prices and for contracts in advance of setting the transition adjustment. In this case, the contract lockdown date is November 1, 2007, which will lead to GRID updates for indicative transition adjustments on November 8, 2007 and the publication of the final transition adjustment rate on November 14, 2007, just before the annual direct access election period opens on November 15, 2007. Prehearing Conference Memorandum, UE 191 (April 18, 2007).

The limited scope of the TAM should dictate both the updates the Company may file and the adjustments Staff and intervenors may propose. (PPL/102, Kelly/4.) But, to ensure that rates are set based upon the most accurate information available, the limitations on the scope of the TAM should not prevent reasonable corrections to information filed in the case. (PPL/102, Kelly/7-8); *see also* UE 170 Order at 9 (allowing corrections in rebuttal testimony over ICNU's objection).

III. UNCONTESTED ADJUSTMENTS

PacifiCorp's July TAM update and rebuttal testimony reflects PacifiCorp's adoption of the following adjustments and policy recommendations by Staff, ICNU, and CUB.

Staff

- *Operating Reserve Adjustments*: PacifiCorp adopted the operating reserve correction proposed by Staff. That correction relates to non-owned generation operating reserves located in the Company's east control area, Hermiston line losses and natural gas swaps. These corrections decreased proposed total company net power costs by $15.8 million in PacifiCorp's July TAM update. (PPL/204, Widmer/4-6.)
- *Carbon Generation Plant*: PacifiCorp adopted Staff's proposed Carbon generation plant adjustment, which increased the Company's Carbon plant capacity factor. Based on the July TAM update, this adjustment reduced total company net power costs by approximately $4.8 million. (PPL/204, Widmer/6-7.)

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

- *Stochastic Net Power Costs Modeling*: The Company has agreed to Staff's recommendation that the Company file a written report to the Commission on the feasibility of estimating NVPC using stochastic modeling, with one qualification as to timing. To provide the Company with adequate time to complete its analysis and incorporate the results of the final Commission order in this case, the Company proposes to file its stochastic modeling report 15 business days after the issuance of the final order in this case. (PPL/204, Widmer/7.)

ICNU

- *Extrinsic Value of Call Options*: ICNU proposed to impute extrinsic value for five call option contracts included in GRID. PacifiCorp adopted a modified version of this adjustment, removing the call contracts from GRID if by doing so, NVPC are decreased, prior to the removal of the option premium. Based upon the July TAM update, this reduces total company net power costs by approximately $5.3 million. (PPL/204, Widmer/23-24.) ICNU's Supplemental Testimony accepts the Company's treatment of this adjustment. (ICNU/114, Falkenberg/2-3.)

- *Excess Reserve Allocation*: ICNU proposed an adjustment lowering PacifiCorp's operating reserves. As noted above, the Company reduced its operating reserves in response to Staff's reserve adjustment, decreasing total company net power costs by $15.8 million. (PPL/204, Widmer/25). ICNU's Supplemental Testimony accepts the Company's adjustment to its reserves. (ICNU/114, Falkenberg/3.)

- *CT Reserve* Capability: PacifiCorp has accepted ICNU's recommendation to prospectively increase the quick start capability of the Gadsby and West Valley CTs from 20 MW to 40 MW. Based upon the July TAM update, this adjustment reduces total company net power costs by approximately $0.2 million. (PPL/204, Widmer/7.)

- *W-E Reserve Transfer*: PacifiCorp has adopted ICNU's general recommendation to leave the Company's PacifiCorp-West/PacifiCorp-East transfer capability turned on in GRID, so that any benefits that may arise can be captured in those limited times when it may be of use. Based upon the July TAM update, this adjustment reduces total company net power costs by approximately $0.2 million. (PPL/204, Widmer/8.)

- *Uneconomic CT Operation*: PacifiCorp has accepted the mechanics of ICNU's proposed adjustment removing West Valley from GRID because the model incorrectly dispatched this resource when it was not the lowest cost resource option. The Company will incorporate the adjustment in the remaining GRID updates if removal of West Valley results in lower net power costs. In the July TAM update, this adjustment reduces total company net power costs by $1.6 million. (PPL/204, Widmer/8.)

- *Planned Outages*: ICNU proposed an adjustment using the 48-month average of actual planned outages for the Gadsby and West Valley CTs and the Currant Creek CCCT. PacifiCorp agrees with the portion of the adjustment relating to the Gadsby CTs, but observes that the West Valley adjustment may not be necessary because the unit will be excluded in the final update if doing so lowers net power costs. The Company disagrees with the proposed Currant Creek CCCT adjustment, because it is a new plant and the Company lacks 48 months of actual information. In the July

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

TAM update, the Gadsby CT adjustment reduces total company net power costs by an immaterial amount. (PPL/204, Widmer/9.)

CUB

- *ECD Update*: CUB proposed to update the hydro-related ECD, using only the variables included in the TAM filing. PacifiCorp objected to this proposal on the basis that such an update would be incomplete and one-sided. CUB and PacifiCorp agreed on a process to review how the ECD should be monitored and potentially updated on a comprehensive basis in response to the TAM and automatic adjustment clauses. This process initially involves setting an ECD baseline for 2007 for future comparisons. The process then requires PacifiCorp to provide an exhibit to its Annual Results of Operations, beginning on May 1, 2008, which shows the value of the ECD and projected value of updating the ECD. Finally, the process contemplates potential filings to update the ECD and the Company's generation costs in rates. CUB has agreed that this agreement resolves its proposed ECD adjustment in this case. (Joint Exhibit/100, PacifiCorp-CUB/1.)

- *Forward Price Curve Benchmark*: CUB proposed that the Company include at least two independently-produced forward electricity and natural gas price curves with its final TAM filing and that the Company explain any deviation of five percent or greater in the filing. In its rebuttal testimony, the Company agreed to make available its forward price curve, along with the independent third-party forward pricing information that the Company uses, for the one-year test period for the final TAM net power costs update. But, because the Company does not have access to underlying third-party data or models, the Company will not be able to explain differences of five percent or more between Company and independent curves. (PPL/204, Widmer/10.)

- *GRID model:* CUB raised procedural concerns about PacifiCorp's introduction of GRID model changes in the TAM, although it acknowledged that the model changes in this case lowered NVPC. In its rebuttal testimony, PacifiCorp agreed to formalize a pre-filing review process for any GRID model changes in the future. PacifiCorp also agreed not to include model changes in future TAM filings if Staff, CUB or ICNU objected to these changes. (PPL/102, Kelly/6-7.)

IV. CONTESTED ADJUSTMENTS

A. Introduction

An applicant utility in a rate case "'shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is just and reasonable.'" *In re Idaho Power*, Order No. 05-871 at 7 (2005). Once the company has presented its evidence, the burden of going forward with evidence that the proposed rates are unreasonable shifts to parties who oppose the rates. *In re NW Natural*, Order No. 99-697 (1999); *see also In re Idaho Power*, Order No. 05-871 at 7 (once the utility has

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

submitted evidence to prove its case, "then the burden of production shifts to parties that oppose the utility's proposal.")

The Commission must base its orders on substantial evidence. Pursuant to the Oregon Administrative Procedures Act, a court "shall set aside or remand [an administrative agency's] order if the court finds that the order is not supported by substantial evidence in the record. Substantial evidence exists to support a finding of fact when the record, viewed as a whole, would permit a reasonable person to make that finding." *See* ORS 183.482(8)(c).

Throughout these proceedings, Staff bears a unique responsibility. Staff's role is not to advocate on behalf of consumers or any other specific group, but instead is to provide independent, balanced, objective recommendations to the Commission. *See* Ruling, UE 115/116, Order No. 01-249 (2001) (Staff does not act as an advocate because advocacy "should be the province of parties who are asserting the interests of the utilities, customer groups, or others with a financial stake in the proceeding.")[1]

B. The Commission Should Reject Staff's Proposed Wholesale Margin Adjustment For Multiple Reasons, Including That It Is Not Supported By Substantial Evidence.

Staff's margin adjustment imputes additional volumes of short-term wholesale transactions, implies a positive margin on these transactions, and relies upon the associated

---

[1] *See also In re Internal Operating Guidelines*, UM 1016, Order No. 01-253, Appendix A (2001) (adopting Internal Operating Guidelines regarding Responsibilities of Utility Program Staff), holding, inter alia, that "In both public meeting and contested case proceedings, the Utility Program Staff provides independent, expert recommendations on issues before the Commission... This Staff responsibility must be discharged consistent with the Commission's obligation to conduct fair proceedings. Directly related to fairness is an obligation to balance the various interests affected by the Commission proceedings. While Oregon law requires the Commission, and by implication, the Commission Staff to represent customers of any public or telecommunications utility in all matters in which the Commission has jurisdiction, this responsibility also carries a broader obligation. Representation, as used here, requires an appreciation of both the interests of the customers in having reasonable rates and the advantages to the customers from having utilities that are able to conduct their operations as financially sound enterprises... With this broad view of representation, the Commission does not perceive Staff as acting as an advocate in Commission proceedings."

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

revenues to reduce PacifiCorp's 2008 Oregon allocated NVPC by $16.2 million. This adjustment is more than twice the size of any other adjustment in the case (Tr. 100), and would function to offset a significant portion of the market, fuel and contract cost increases upon which the 2008 TAM forecast is based. Notwithstanding the magnitude of Staff's margin adjustment, it lacks the basic evidentiary foundation necessary to prove even routine adjustments and has multiple theoretical and policy problems:

- Other than a general, four-sentence description at Staff/100, Wordley/6-7, Staff has not introduced any evidence of the calculation of the adjustment into the record in this case.
- The record does include the alternative calculations for this adjustment that Staff proposed in three other PacifiCorp cases. (PPL/601, Pages/3-8.) Staff testified that its theory and calculation of the margin adjustment has not changed materially from previous cases to this one. (Tr. 103.) Application of the alternative calculations to this case produces very different results, however, ranging from an increase in PacifiCorp's Oregon allocated power costs of $16.7 million (based on Staff's UE 116 calculation) to a decrease of $1.2 million (based on Staff's UE 147 calculation). (PPL/208, Widmer/1, 8.)
- Staff imputes additional volumes of wholesale transactions based upon PacifiCorp's actual results during the last three rate case test periods. But Staff acknowledged that it never attempted to determine what percentage of these additional transactions were actually related to trading, where the concept of margin is applicable, and what percentage were related to system balancing, where the concept is not. (Tr. 125.) The undisputed evidence is that, during the adjustment period, system balancing comprised 87 percent of PacifiCorp's total short-term transactions. (PPL/500, Apperson/1.)

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

- While Staff's theory is that PacifiCorp's NVPC will be overstated without a margin adjustment, Staff never tested this by comparing power costs in rates to actual results. (Tr. 128.) In fact, over the last five years, PacifiCorp's power costs in rates were, on average, understated by more than $60 million per year. (Tr. 147; PPL/207, Widmer/1.)
- Staff's margin adjustment is inconsistent with the Commission's recent rejection of Staff's extrinsic value adjustment in UE 180, where the Commission recognized that the inherent value of power supply systems should be captured by comprehensive modeling changes, not one-factor adjustments. An important factor in the Commission's analysis was the fact that PGE's power costs were generally underestimated by its power cost model, similar to PacifiCorp's experience.
- Staff's margin adjustment is also problematic regulatory policy because it imputes an actual cost model into a normalized ratemaking paradigm. This problem is compounded by Staff's failure to compensate in its adjustment for differences in actual results in variables that impact volume and margin on short-term wholesale transactions, such as new resources not included in rates, hydro generation, fuel costs, and thermal availability. (Tr. 125-27.)

1. Staff's Margin Adjustment is Not Supported by Substantial Evidence.

Staff's testimony in this case provides no more than a general description of the theory and calculation of its margin adjustment, without supporting detail, exhibits or documentation for the adjustment. Without ever introducing the margin adjustment calculation into evidence, Staff relies upon the calculation as its only evidence that the Company makes a positive margin on its wholesale transactions not covered in GRID. (Tr. 127-28.)

The evidence in the record demonstrates that the margin adjustment calculation is highly volatile, making the details of it critically important to the Commission's review of this

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

adjustment. Staff has proposed the margin adjustment in PacifiCorp's last five rate cases, all of which were resolved by Stipulation and without a Commission ruling on the adjustment. (Tr. 101.) In response to PacifiCorp Data Request 3.2, Staff stated that:

> "Staff's margin adjustment has always been proposed for the purpose of sharing with retail customers inherent value in the company's power system in addition to the value captured by the company's power cost modeling used for ratemaking. Neither PDMac (used in UE 116) or GRID (used in UE 134, UE 147, UE 170, UE 179 and UE 191) include all of the inherent value of the company's power system. Staff's method of calculating an estimate of this additional value has changed slightly over the now six cases Staff has proposed the margin adjustment. The proposed adjustment has always been based on an estimate [of] the volume of expected wholesale sales and purchases transactions above the level captured by the power cost models, and $/MWh margin (average sales price less average purchase price). The source of data has always been actual historical data provided by the company. ..." (Staff Response to PacifiCorp DR 3.2, PPL/601, at 1.)

In summarizing this response, Staff agreed that over the last six cases (the previous five cases plus this case) neither the theory nor the calculation of its margin adjustment had changed materially. (Tr. 103.)

The evidence demonstrates that, while the alternative margin-adjustment calculations may differ only slightly from that proposed in this case, when those alternative calculations are applied to this case they produce completely different results from Staff's proposed adjustment. Exhibit 601 contains Staff's files produced in response to PacifiCorp DR 3.2, which are the calculations underlying Staff's margin adjustment in UE 116, UE 134 and UE 147. (PPL/601, Pages 3-8; Tr. 109.) Exhibit 208 demonstrates the results of the UE 116, UE 134 and UE 147 margin adjustments as applied to this case, which are, respectively, a $16.7 million Oregon allocated NVPC increase, a $2.4 million Oregon allocated NVPC increase and a $1.2 million Oregon allocated NVPC decrease. (PPL/208, Widmer/1, 5, 8.)

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

Staff's response to PacifiCorp DR 3.2 acknowledged that the various margin calculations produced in Exhibit 601 are all designed to accomplish the purpose of sharing the inherent value of PacifiCorp's power cost system not captured by GRID. Staff also acknowledged that the concept of sharing the value of a power cost system normally entails sharing both risks and rewards. (Tr. 103.) While Staff's theory is that the Company will never experience implied negative margins—such that the margin adjustment would produce a rate increase, not a rate decrease—that is precisely the result produced by application of the UE 116 and UE 134 margin adjustment calculations in this case. (Tr. 104; PPL/208, Widmer/1, 5.) This result makes sense because, on an actual basis, PacifiCorp has experienced implied negative margins on its total wholesale transactions in the last three of five years, and PacifiCorp has an implied positive margin in this case of $2.93 MWh. (PPL/204, Widmer/18.)

The alternative adjustment calculations in PPL/208 are the only margin adjustment calculations now in the record, with results that could be averaged to support a rate increase instead of a rate decrease in this case. For all of the reasons stated below, however, PacifiCorp does not support Staff's margin adjustment whether it goes in the Company's direction or not. Instead, PacifiCorp relies upon the results of the alternative calculations to demonstrate that Staff's margin adjustment: (1) can produce both higher or lower rates, depending on the Company's historical data; (2) is so unreliable that "slight" and "immaterial" changes in the calculation can produce a major swing in outcomes, such as the $32 million Oregon allocated NVPC difference between the adjustment proposed in this case and the adjustment calculated using the UE 116 methodology; and (3) lacks consistency and predictability, except to the extent that the adjustment has always been applied to produce a large rate decrease, notwithstanding major changes in PacifiCorp's actual results.

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

2. PacifiCorp's Additional Short-term Wholesale Transactions are Mostly System Balancing Transactions, not Margin-Producing Trading Transactions.

In its testimony, Staff explains that its margin adjustment is justified not because GRID underestimates short-term wholesale transaction volume, but because PacifiCorp makes a positive margin on these transactions. (Staff/100, Wordley/5.) Staff points to the "large amounts of profit opportunity, based upon trading that PacifiCorp can and does take advantage of." (Staff/200, Wordley/4.) Staff dismisses as "not credible" PacifiCorp's claim that the additional wholesale transactions are mostly system balancing transactions because the volume of these transactions is high compared to PacifiCorp's load. (*Id.* at 5.)

Staff admitted, however, that it never attempted to determine what percentage of PacifiCorp's short-term transactions were related to system balancing and what percentage were related to trading. (Tr. 124-25.) This distinction is critical to Staff's margin adjustment because the concept of earning "margins" is inapplicable to system balancing transactions, where the Company makes purchases because of a short position or sells because of a long position. (Tr. 132; 145-46.)

During the time period covered by Staff's margin adjustment (2003 to 2006), on average system balancing transactions made up over 87 percent of PacifiCorp's short-term transactions, with arbitrage and trading transactions comprising the balance. (Tr. 134; PPL/500, Apperson/1.) During the same time period, PacifiCorp's actual, Oregon allocated margins on its arbitrage and wholesale trading activity averaged $0.8 million annually. (Tr. 134-35; PPL/500, Apperson/1.)

Contrary to Staff's suggestion, system balancing volumes are not directly related to load. This is because system balancing is a dynamic process that involves continual rebalancing from the time the position comes within the Company's purview to the hour of delivery. (Tr. 136.) Thus, for any given position, the Company engages in multiple system balancing transactions, resulting in large volumes of such transactions relative to its load. (*Id.*)

3. PacifiCorp's Power Costs in Rates are Historically Understated, a Problem that Staff's Margin Adjustment Would Exacerbate.

Implied in Staff's margin adjustment is the position that approval of PacifiCorp's TAM increase without a margin adjustment would lead to an overstatement of power costs. Staff admitted, however, that it never attempted to compare PacifiCorp's net power costs in rates to its actual results during the adjustment period. (Tr. 128.)

Over the last five years, between 2002-2006, PacifiCorp's total company NVPC were understated in Oregon rates by an average of $61.9 million annually. (PPL/207, Widmer/1.) Additionally, current results through May 2007 show that total company power costs in Oregon rates are understated by $65 million. (Tr. 147.)

In PGE's last general rate case, UE 180, Staff acknowledged "NVPC forecasts are more likely to underestimate NVPC than overestimate it." UE 180 Order at 11. PacifiCorp's historical experience bears this out. PacifiCorp's NVPC are more accurately forecast without Staff's margin adjustment than with it.

4. The Commission Should Apply the Same Rationale in Responding to Staff's Margin Adjustment as it used in Analyzing Staff's Extrinsic Value Adjustment in UE 180.

In PGE's last general rate case, UE 180, Staff proposed an extrinsic value adjustment similar to the margin adjustment proposed in this docket. PGE opposed Staff's proposed adjustment, arguing "that such an adjustment would 'cherry-pick' one aspect of uncertain power cost forecasts, simply to justify a reduction in forecast NVPC... PGE introduced evidence showing that baseline NVPC forecasts are often underestimated, and that a more complete assessment, which captured the uncertainty of power cost forecasts, would increase net variable power costs." UE 180 Order at 10.

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

The Commission agreed with PGE, concluding that "to only consider one factor would not be reasonable," especially because PGE's model generally understated PGE's power costs in rates. UE 180 Order at 12. The Commission recognized that a better outcome was to work toward a new power cost model that more comprehensively captures the costs and benefits of stochastic volatility. *Id.* The Commission ordered PGE to analyze stochastic power cost modeling and announced that the Commission would open a new generic docket to review this issue.

The Commission should apply the same approach in this case, rejecting Staff's adjustment in favor of a more comprehensive review of power cost modeling in the generic docket announced in UE 180. The margin adjustment and extrinsic value adjustments are so similar that PacifiCorp argued that they constituted a double-count when Staff previously suggested both adjustments in a rate case. (Tr. 144.) The rationale for the adjustments is essentially the same, which is that customers should get the benefit of the operational flexibility of the power supply system. (Staff/100, Wordley/6.) Finally, in this case, as in UE 180, it is unreasonable to make a one-factor, ad-hoc adjustment to power costs to capture certain benefits when power costs are already systematically understated in rates.

5. Staff's Margin Adjustment is Poor Regulatory Policy Because it Imputes Actual Results into A Normalized Ratemaking Paradigm and Does so Inconsistently.

Staff's margin adjustment is essentially an historical true-up adjustment for prior unrelated periods for short-term wholesale transactions within a power cost model that is otherwise based upon normalized forecasts. To adopt Staff's margin adjustment, consistency and matching principles would require adoption of similar true-ups (without deadbands or sharing) for other cost items with actual results that generally vary from normalized forecasts, such as new resources not included in rates, hydro generation, loads and forced outages. (PPL/204, Widmer/15-16).

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

Staff failed to consider, adjust or compensate for differences in actual results in any of these variables, each of which directly impacts the volume and implied margin on wholesale transactions. (Tr. 125-27.) Staff explained that it did not consider any of these variables because they were "noise." (*Id.*) But, just looking at one of these factors—new resources not yet included in rates—shows how significant these variables can be in terms of actual volumes of short-term transactions. In 2006, neither PacifiCorp's Currant Creek CCCT nor Leaning Juniper wind farm were in rates in Oregon (because neither were in operation at the start of the test year), but both came on line in the year. During that year, these plants produced 1.9 million MWh. (Tr. 143.) Staff's margin adjustment unfairly includes the volumes and revenues from wholesale transactions associated with these plants, without any offsets for the associated costs.

Staff justifies its deviation from normalized ratemaking as necessary to capture values that GRID does not quantify. But, the undisputed evidence is that GRID does capture the value of the operation of PacifiCorp's system by using available transmission for trading and by backing down generation. (PPL/204, Widmer/15.) And, GRID calculates this value on a normalized basis, consistent with the treatment of other net power cost components.

In summary, the evidentiary and policy problems associated with the margin adjustment are myriad. The adjustment undermines fair, just and reasonable rates, instead of ensuring them. The Commission should reject the margin adjustment in this case and direct Staff to raise its concerns about the modeling of short-term wholesale transactions in the Commission's upcoming generic docket on stochastic modeling.

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

C. The Commission Should Reject ICNU's Remaining Adjustments.

1. ICNU's "NVPC in Rates" Adjustment Violates the UE 179 Stipulation and Should Be Rejected.

ICNU proposes a $7.49 million adjustment to PacifiCorp's proposed Oregon allocated power cost update for 2008 based on ICNU's assertion that PacifiCorp's 2007 Oregon allocated TAM costs were $225 million, $7.49 million higher than the $217.5 million Oregon allocated 2007 TAM baseline from which PacifiCorp calculated the proposed TAM increase in this case.

ICNU's calculation uses the UE 170 total company NVPC, allocates it to Oregon using UE 170 allocation factors, produces a $215 million Oregon allocated NVPC baseline, and adds the $10 million TAM increase from UE 179 to this amount. (ICNU/100, Falkenberg/6; ICNU/103.)

PacifiCorp's calculation uses the 2007 TAM/total company NVPC cap of $834.4 million specified in the UE 179 Stipulation and allocates it to Oregon using UE 179 allocation factors. PacifiCorp's final 2007 total company NVPC forecast was $872.6 million, thus implicating the $834.4 million total company NVPC cap in the UE 179 Stipulation. (PPL/102, Kelly/10.)

There are seven reasons why the Commission should reject ICNU's adjustment.

First, the adjustment is contrary to the express terms of the UE 179 Stipulation, signed by ICNU and approved by the Commission in Order No. 06-530. The Commission has recognized a strong public policy favoring compromise and settlement of disputes. *See In re PGE and PacifiCorp*, Order No. 92-557, 133 PUR 4th 145 (1992). A key aspect of facilitating this strong public policy is enforcement of stipulations according to their express terms.

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

In Section 5 of the Stipulation, the parties specified how the 2007 TAM rates would be calculated and specifically provided that the 2007 total company NVPC/TAM would be $834.4 million if PacifiCorp's power costs reached the cap:

> b. NVPC/TAM . . . the Parties agree to a NVPC/TAM rate increase for 2007 capped at a maximum of $10 million. This increase will be calculated using the following steps:
>
> (i) Begin with PacifiCorp's proposed UE 179 total Company NVPC of $889.4 million.
>
> (ii) Subtract $50 million, producing an adjusted NVPC of $839.4 million. . . . The Parties agree that this procedure will ensure that the NVPC/TAM increase for 2007 will not exceed a maximum of $10 million allocated to Oregon. . . .
>
> (iii) Subtract PacifiCorp's current NVPC of $796.5 million from the adjusted UE 179 NVPC of $839.4 million to determine the total NVPC-related increase before 2007 TAM updates and before application of the $10 million cap. . . . ***Regardless of the final TAM amount, the total Company NVPC for 2007 will be capped at $834.4 million, and the NVPC increase will be capped at $37.9 million.*** Exhibit A contains the calculation used to derive these amounts.
>
> . . . . .
>
> (v) The ultimate level of the NVPC/TAM increase for 2007 will be based upon the difference between the total Company NVPC in rates as approved in UE 170 and the total Company NVPC in rates after completion of the TAM process in this case. . . . [T]he Parties agree that the total Company NVPC/TAM limitation agreed to in this Stipulation will ensure that the NVPC/TAM increase for 2007 is not more than $10 million allocated to Oregon.

(PPL/600, Pages 18-19 (emphasis added).) ICNU contends that these provisions, including the identification of the $834.4 million cap, "really served no purpose, other than to determine whether the $10 million increase was going to be granted or not." (Tr. 69; ICNU/100, Falkenburg/5.) ICNU makes this argument precisely because its adjustment cannot be reconciled with the Section 5 calculation.

The Commission's order approving the Stipulation reads Section 5 according to its plain meaning and contrary to ICNU's interpretation: "The Stipulation sets forth a calculation

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

to determine the ***final NVPC/TAM revenue requirement,*** but the final number is dependent on PacifiCorp's completion of the TAM process." *In re PacifiCorp*, Order No. 06-530 at 3 (2006) (emphasis added). The Order approving the UE 179 Stipulation clearly contemplated use of the Section 5 calculation to set the 2007 TAM revenue requirement, not just to determine whether PacifiCorp was eligible for the full $10 million 2007 TAM increase.

Second, ICNU's adjustment effectively replaces the words "total company" in Section 5.b (v) of the UE 179 Stipulation with the words "Oregon allocated" as follows:

> The ultimate level of the NVPC/TAM increase for 2007 will be based upon the difference between the total Company **[ICNU*:* *Oregon allocated*]** NVPC in rates as approved in UE 170 and the total Company **[ICNU*:* *Oregon allocated*]** NVPC in rates after completion of the TAM process in this case.

(PPL/600, Page 19.)

The Commission should not rewrite the Stipulation in this manner and should instead construe the Stipulation according to its plain meaning, which dictates the calculation PacifiCorp used in this case. This is especially true because Commission rules preclude parties from introducing evidence about the negotiations of a stipulation, including evidence that could demonstrate that a change such as that outlined above was proposed and rejected. *See* OAR 860-014-0045 ("No admission or offer of settlement made during compromise negotiations, including a settlement conference under these rules, shall be admissible in evidence against the party making the admission or offer in any formal hearing before the Commission.").

Third, ICNU contends that the 2007 TAM/NVPC calculation in the UE 179 Stipulation applied only to determining whether PacifiCorp got the $10 million increase, not to setting power costs in rates in UE 179 for reference in future cases. (Tr. 73-74.) In fact, Section 10 of the Joint Stipulation expressly binds the parties to use of the Section 5 methodology in future cases such as this one:

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

> By entering into this Stipulation, no Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Party in arriving at the terms of this Stipulation, ***other than those specifically identified in the body of this Stipulation***. No Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, ***except as specifically identified in Section 5 of this Stipulation***. (PPL/600, Page 24 (emphasis added.))

Fourth, ICNU's calculation produces a total company NVPC that produces a facial violation of the UE 179 Stipulation. ICNU testified that its proposed $225 million Oregon allocated power cost baseline translates into total company NVPC for 2007 of approximately $861 million. (Tr. 82.) This result disregards the Joint Stipulation's express requirement that "the total Company NVPC for 2007 will be capped at $834.4 million."

Fifth, ICNU contends that PacifiCorp's use of the $834.4 million baseline identified in the UE 179 Stipulation deprives customers of the benefit of the decline in allocation factors that took place between UE 170 and UE 179. (Tr. 79.) And, indeed, ICNU's proposed NVPC baseline of $225 million can be derived on an approximate basis by applying UE 170 allocation factors to the $834.4 million NVPC cap, instead of the appropriate (but lower) UE 179 allocation factors applied by PacifiCorp to derive the $217.5 million baseline. (*Id.*)

In executing the UE 179 Stipulation, ICNU expressly agreed to calculate the NVPC/TAM increase by comparing total company power costs from UE 170 and UE 179 and allocating the difference using specified UE 179 allocation factors. (PPL/600 at 33 (Exhibit A to the Joint Stipulation) (using composite UE 179 allocation factor of 26.4 percent to determine 2007 TAM cap.)) The Commission should reject ICNU's attempt in this case to revisit its bargain in UE 179 by reworking the 2007 NVPC calculation using UE 170 allocation factors instead of the applicable, agreed upon UE 179 allocation factors.

Sixth, PacifiCorp's final TAM/total company NVPC filing in UE 179 was approximately $40 million higher than the UE 179 cap of $834.4 million. (PPL/200, Widmer/4.) The cap in the UE 179 Stipulation thus benefited Oregon customers by

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

approximately $10 million (approximately 26 percent of $40 million). Having benefited greatly from the cap, it is unfair for ICNU to now ask the Commission to ignore the cap and impute a higher NVPC in rates for 2007 to limit the rate increase in this case. By its adjustment, ICNU effectively seeks to recover $7.5 million of the $10 million TAM increase granted in UE 179, an adjustment barred by retroactive ratemaking principles.

Seventh, application of ICNU's theory for calculating the NVPC rate increase in this case to calculation of the overall rate increase in UE 179 demonstrates the problems with ICNU's theory in the context of negotiated settlements and changing allocation factors. Oregon allocated, non-NVPC costs in UE 170 were $252.5 million. The UE 179 Stipulation proposed a $33 million increase to these amounts, which would have resulted in an Oregon allocated, non-NVPC cost increase of $285.5 million ($252.5 million plus $33 million) using ICNU's theory. However, the Oregon allocated, non-NVPC costs in UE 179 were actually $295 million, demonstrating that the ICNU approach is inconsistent with how overall rates were set in UE 179. (ICNU/116, Page 1.)

For all of these reasons, ICNU's NVPC in rates adjustment should be rejected. Instead, the Commission should reinforce its strong policy supporting and enforcing settlements by using the 2007 total company TAM baseline determined by the UE 179 Stipulation, allocated to Oregon using UE 179 allocation factors, to calculate the 2008 TAM increase.

2. ICNU's Thermal Outage Adjustment Is Inconsistent with Applicable Oregon Precedent and Unwarranted Given PacifiCorp's Overall Thermal Plant Performance.

PacifiCorp calculated its forced outage rate in this case using a rolling four-year average, which is the Commission's "long-standing practice." *See* UE 180 Order at 13, 15. (noting PGE's argument that the Commission has applied this practice for 20 years). ICNU proposes to change the forced outage calculation by excluding outage costs that it alleges were caused by management or personnel errors, avoidable mistakes and/or manufacturer

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

design flaws. This lowers the forced outage rate in this case and results in a proposed adjustment of approximately $6 million total company.

ICNU's thermal outage adjustment should be rejected because it deviates from applicable Commission precedent. The adjustment is also unwarranted given PacifiCorp's overall thermal plant performance.

a. ICNU's Forced Outage Adjustment is Inconsistent with Long-Standing Commission Precedent and the Commission's Recent Policy Direction in the UE 180 Order.

In PGE's last rate case, UE 180, the parties argued for different methods of calculating PGE's forced outage rate other than the rolling four-year average. Staff advocated use of industry-wide averages from the North American Electric Reliability Council (NERC). UE 180 Order at 14. CUB supported Staff's approach and ICNU proposed to "use NERC average outage rates for plants that are comparable." *Id.* The Commission rejected application of these new approaches in UE 180 and instead decided to continue to rely upon a four-year rolling average:

> "In determining a method for establishing the forced outage rate, we seek the most accurate forecast of forced outages at the relevant plants. We continue to believe that past performance is the best predictor of a plant's outage rate. For this reason, we adhere to our long-standing practice of using actual plant outage rates to predict the future activity of that plant." *Id.* at 15.

PacifiCorp's current TAM filing conforms with this Order, in contrast to ICNU's adjustment which deviates from it.

In its UE 180 Order, the Commission also recognized the need for a policy-based, generic review of the calculation for forced outage rates: "we appreciate the concerns of the parties that the four-year rolling average may not always be the most accurate forecast of future outages. For this reason, we will open a new generic docket to examine this issue." *Id.* The UE 180 Order thus directs continuation of the use of a rolling four-year average, pending review of alternative calculations in a generic Commission docket.

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

This interpretation of the UE 180 Order is confirmed by Staff's testimony in PGE's current annual update filing, UE 192. Staff explained that it did not propose an adjustment to the forced outage rate in that case because the Commission had "indicated that it would open a new docket to review the appropriate methodology for determining 'normal' forced outage rates for generating plants," and that "the Commission's upcoming investigation into the appropriate methodology for determining 'normal' equivalent forced outage rates is the appropriate docket to revisit the use of NERC data, or other methods, for determining forced outage rates." (PPL/605, Pages 6-7.)

There are several policy issues implicated by ICNU's adjustment, all of which require consideration in the Commission's generic docket rather than this case.

First, ICNU proposes to reduce PacifiCorp's forced outage rate by any outage that it claims was PacifiCorp's fault. While examining specific case-by-case reports of error, ICNU ignores data demonstrating that PacifiCorp's overall plant performance matches or exceeds NERC industry averages. ICNU's emphasis on isolated mistakes or errors rather than overall plant management sets poor regulatory policy, and could easily lead to an approach to plant maintenance that reduces outages but raises costs.

In a prudence review, the Commission examines the objective reasonableness of a company's actions measured at the time the company acted. *In re PacifiCorp*, UM 995, Order No. 02-469 (2002). In this context, the objective reasonableness of PacifiCorp's thermal plant operation and maintenance can be confirmed by PacifiCorp's overall performance at or above NERC averages, as outlined below.

Second, ICNU's proposal to charge the utility with outages due to manufacturer problems raises similar but even more complicated policy issues. A review of ICNU's Confidential Exhibit ICNU/117 reveals that almost one-half of ICNU's adjustment is due to one particular outage caused by a manufacturer defect. ICNU's suggestion to impute a prudence disallowance based on manufacturer error significantly lowers traditional prudence

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

standards in Oregon and overstates the holding of *In re Portland General Electric*, Order No. 95-322 (1995).

ICNU contends that "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." (ICNU/100, Falkenberg/29.) In fact, the Commission's holding was expressly limited to the UE 88 case. The Commission specifically noted that it "decides cost recovery issues on a case by case basis," and that "no future outcome is determined by the decision to impute the cost of steam generator replacement to PGE by removing their cost from the net benefits analysis." Order No. 95-322 at 62. In any event, the scope of the Commission's prudence standard in the context of plant outages caused by manufacturer defects and the interpretation of the UE 88 order is more appropriate to a generic policy docket than to these proceedings.

Third, ICNU has relied on selected portions of selected PacifiCorp root cause analysis (RCA) reports to establish an adjustment to outage rates. There are many significant policy issues implicated by this. Most fundamentally, ICNU takes reports that are developed and maintained for prudence purposes and inappropriately uses them to establish imprudence.[2]

---

[2] At the hearing, ICNU proposed to offer Exhibit 210, a Wyoming settlement agreement between PacifiCorp's Rocky Mountain Power division and other parties which addressed, among other things, certain of the forced outages ICNU relies upon for its adjustment in this case. PacifiCorp objected to this exhibit because settlement agreements are generally inadmissible under Oregon rules of evidence. *See* ORS 40.190, alternatively cited as OEC 408 (evidence of furnishing or offering or promising to furnish, or accepting or offering or promising to accept, a valuable consideration in compromising or attempting to compromise a claim which was disputed as to either validity or amount, is not admissible to prove liability for or invalidity of the claim or its amount.) The Commission's rules track this rule of Oregon evidence. *See* OAR 860-014-0045 (5) (No admission or offer of settlement made during compromise negotiations, including a settlement conference under these rules, shall be admissible in evidence against the party making the admission or offer in any formal hearing before the Commission.) To the extent that ICNU asks the Commission to take official notice of Exhibit 210 in its Opening Brief, PacifiCorp renews this objection.

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

ICNU's use of the outage reports in this manner could discourage utilities from carefully reviewing and remediating specific outage incidences. There is a strong public policy against using evidence of subsequent remedial measures to prove negligence, or in this case imprudence, because the logical consequence of such a finding is to decrease incentives to take preventative measures. *See* OEC 407, also cited as ORS 40.185 (providing that "[w]hen, after an event, measures are taken which, if taken previously, would have made the event less likely to occur, evidence of the subsequent measures is not admissible to prove negligence or culpable conduct in connection with the event").

Additionally, ICNU's selective use of the Company's outage reports is misleading because it lacks necessary context. As explained in PPL/606 (the Company's response to ICNU's data request 13.56), while ICNU relies on a sampling of RCA reports, it fails to describe the total context of each decision or outcome of the RCA. To take just one example, in ICNU/100 Falkenberg/26, Mr. Falkenberg notes that a unit was run an additional seven hours, and that this was part of "multiple compounding avoidable errors." However, the reason the unit was run seven hours was to get the unit to off-peak hours. By delaying an outage seven hours, PacifiCorp had the unit off line for one peak period instead of two peak periods, thus minimizing net power costs. (PPL/606, Pages 1-2.)

The Commission should refer all of the complex and important issues implicated by ICNU's forced outage adjustment to the Commission's upcoming generic docket.

b. PacifiCorp's Plant Performance Is At or Above Industry Standards, As Measured By NERC Data.

PacifiCorp introduced NERC data that demonstrates that: (1) PacifiCorp's forced outage rate is declining and is now near the industry average; (2) PacifiCorp's planned outage factor and equivalent availability factor, which result from the combination of forced outages and planned outages, are consistently better than the industry average; and (3) the

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

capacity factor, which is a measure of actual output, shows that PacifiCorp's thermal unit performance far exceeds industry average. (PPL/400, Mansfield/6.)

Most significantly, PacifiCorp's capacity factor for the four-year period ending in December 31, 2005 is approximately 10 percent greater than the NERC average. PacifiCorp's above-average thermal availability results in approximately $292 million in savings in annual total company power costs and comparatively low net power costs. (PPL/400, Mansfield/13.) In addition, PacifiCorp's percent equivalent availability factor attributed to personnel error is small, and is in line with NERC averages. (PPL/400, Mansfield/10.)

All parties to UE 180, including ICNU, argued for reference to NERC averages in setting the forced outage rate. UE 180 Order at 14. Because PacifiCorp's overall thermal availability statistics are higher than NERC averages, such an approach could increase PacifiCorp's forced outage rate in this case, rather than decrease it as ICNU's adjustment suggests.

Because there is no evidence of overall imprudence in PacifiCorp's plant operation and maintenance, a prudence disallowance related to PacifiCorp's forced outage rates is unwarranted. ICNU's forced outage adjustment should be rejected.

3. ICNU's Station Service Adjustment Inappropriately Disallows a Component of PacifiCorp's NVPC.

ICNU proposes to eliminate the Company's station service adjustment because it contends that the adjustment is trivial, not well supported and is not industry standard. ICNU's proposed adjustment would reduce forecast total company NVPC by $3.5 million. (ICNU/114, Falkenberg/2.)

Station service is modeled as an addition to retail load to capture the associated system cost of running generation stations when the generation units are off line. Net generation only captures station service when the units are running, thereby excluding

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

station service when the units are not running. Unless a separate load adjustment is made as proposed by the Company, the costs of station service will not be recovered by the Company. (PPL/204, Widmer/32.)

ICNU first suggests that the station service adjustment should be eliminated because the adjustment is "quite novel and contrary to standard industry practice." (ICNU/100, Falkenberg/40.) Given the unique aspects of PacifiCorp's six-state generation system, whether or not another utility models station service during outages in the same manner as the Company is irrelevant.

ICNU states that the Company's adjustment reflects situations when unit generation is reduced due to station service, but ignores the thousands of hours when generators are operating at a higher capacity than the GRID model inputs assume. (ICNU/100, Falkenberg/40.) This is incorrect. For example, the Company's GRID modeling produces 45.1 million MWh of coal generation, which exceeds the actual 48-month period ended December 2006 amount of 44.6 million MWh. (PPL/204, Widmer/33.)

The Company's adjustment is not trivial. Station service is a real and substantial cost incurred to serve customers that should be recoverable. ICNU suggests that its adjustment is reasonable because there are times when the Company's generation exceeds the maximum ratings modeled in GRID. That reasoning is not consistent with normalized ratemaking. As explained by ICNU, the higher operating levels are due to factors such as cooler operating temperatures, higher fuel quality and other circumstances, which allow generators to briefly exceed their rated capacities. This limited variation in generation does not belong in normalized ratemaking. (PPL/204, Widmer/32-33.)

The proposed adjustment should be rejected because the Company's adjustment is not one-sided, is not trivial and is modeled appropriately. (PPL/204, Widmer/33.)

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

4. The Commission Should Not Reverse Input Changes for Dave Johnston and Cholla.

ICNU proposes adjustments to reverse two input changes made by PacifiCorp: a 10 MW capacity decrease in the maximum capacity for Dave Johnston Unit 3 from 230 to 220 MW, and an increase in the minimum capacity of Cholla 4 from 150 to 250 MW. (ICNU/100, Falkenberg/30-39.) Both adjustments should be rejected.

a. Dave Johnston Unit 3 (DJ-3)

ICNU's opposition to decreasing DJ-3's net generation capability from 230 to 220 MW rests on its claim that for the four-year period ending December 31, 2006, there were more than 5900 hours when the unit capacity exceeded 220 MW. The proposed adjustment would reduce total company NVPC by $3 million.

There are two problems with ICNU's proposal. First, the proportion of hours during which the unit's capacity exceeded 220 MW was actually very small. The Company has reviewed the 48-month historical generation levels ending December 2006, consistent with the data used to determine the thermal de-rates included in GRID. The Company found that over the last two years of the data, the generation level was above 220 MW, on average, approximately 5.0 percent of the time. During these hours, the level of generation was on average 225 MW or less. This is due to variations in the sulfur content of the coal source. Through the Company's use of targeting the SO2 emission limit, the level of generation could be slightly above 220 MW a limited amount of time but not consistently. (PPL/204, Widmer/35.)

Second, ICNU misses the significance of the Company's proposed reduction. DJ-3 is limited by state law to 1.2 lb/MMBtu of SO2 emission as long as the heat input is below 2500 MMBtu/hour. If the unit exceeds the 2500 MMBtu heat input number, a reduction in the SO2 emission rate is triggered to 0.5lb/MMBtu SO2, which is far more difficult to meet. It is to the Company's and its customers' advantage for the SO2 emission rate to remain at

1.2 lb/MMBtu, rather than 0.5 lb/MMBtu; in order to satisfy a 0.5 lb/MMBtu standard, the Company would have to either build a scrubber by the end of the test period or find a lower sulfur coal source, solutions which are not easily available. The Company has determined that by running the unit at the 2500 MMBtu/hour heat input, the unit produces approximately 220 MW of net generation. (PPL/204, Widmer/34-35.) As a result, reducing net generation capability to 220 MW is important in order to keep the unit functioning at an acceptable emission rate and avoid unnecessary expenses to the Company and its customers.

If ICNU's proposal to change the capacity at DJ-3 to 230 MW is accepted, GRID would calculate the Equivalent Availability of this unit above 220 MW 100 percent of the time. Given the historical data and the Company's SO2 emission limit target, this adjustment is unreasonable.

b. Cholla 4 minimum

ICNU objects to changing the minimum capacity of Cholla 4 from 150 to 250 MW, claiming that PacifiCorp's input assumption "assumes the 'worst case scenario' occurs 100% of the time." (ICNU/100, Falkenberg/39.) ICNU's adjustment would reduce proposed total company NVPC by $0.4 million.

The Company has been modeling Cholla 4 minimum operating capacity at 250 MW for several years. The plant's physical minimum operating level is 95 MW. Due to transmission constraints, the Company is limited to a minimum generation level of 150 MW. Additionally, a sodium depletion problem causes the minimum loading of the plant to increase up to 250 MW in a period of 60 days after an outage. After an outage, however, the sodium depletion issue clears up. (PPL/204, Widmer/38.)

While ICNU focuses on how often the unit operates below 250 MW, it fails to realize that with the removal of hours due to thermal ramping prior to or after an outage, the unit historically has operated below the 250 MW level only 3.0 percent of the time over the four years ending December 2006. (Table 2, PPL/204, Widmer/39.) This data shows that the

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

Company's modeling has not assumed a worst case scenario and ICNU's proposed adjustment should be rejected. (PPL/204, Widmer/39.)

5. PacifiCorp's Proposed Outage Schedule for Currant Creek CCCT Should Be Approved.

ICNU has proposed adjustments to the planned outage rates for the Gadsby and West Valley CTs and the Currant Creek CCCT. The Company agreed to ICNU's adjustments for Gadsby and West Valley, but not to the adjustment for Currant Creek. (ICNU/114, Falkenberg/3; PPL/204, Widmer/9.) The impact of the Currant Creek adjustment on total company NVPC is $0.6 million.

ICNU objected to the Company's use of a planned outage schedule for Currant Creek that differs from the typical four-year historical average of one or two days for planned maintenance. (ICNU/100, Falkenberg/42.)

PacifiCorp assumed a minimum of one week for maintenance outages for Currant Creek, because it is a new plant that lacks the 48 months of history to create a normalized maintenance level. There is no historical average on which to project planned maintenance. When a new generating unit comes online, it is PacifiCorp's policy to estimate planned maintenance schedules based on manufacturers' recommendations. For the types of units used at the Currant Creek plant, the manufacturer GE Energy has recommended schedules for various maintenances. Based on GE Energy's recommended schedules, PacifiCorp made a conservative estimate and modeled the seven-day maintenance schedule for Currant Creek. (PPL/204, Widmer/40.) This assumption is more reasonable than ICNU's assumption, which is based upon a one-day maintenance period drawn from averages for other plants that are beyond their initial start-up phases. (ICNU/114, Falkenberg/3.) ICNU's adjustment to the planned outage rate for Currant Creek should be rejected.

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

6. ICNU's Hydro Modeling Adjustment Should be Rejected.

ICNU makes various objections to the Company's VISTA hydro modeling, and proposes an adjustment to total company NVPC of $1.7 million. (ICNU/114, Falkenberg/2.)

a. Correlation among Hydro Facilities.

ICNU first objects that the Company's hydro modeling assumes that generation from all of its hydro resources is perfectly correlated, and that every generator experiences identical conditions every month of the year. (ICNU/100, Falkenberg/16.) This is incorrect. Instead, the model assumes that generation will not exceed certain extreme levels of "dry" and "wet" conditions, an assumption that conforms to the Company's historical data.

Historically, the Company included greater extremes and more points across a range of possible outcomes for its VISTA modeling. However, upon reviewing the data, the Company found that the included extremes were greater than any year in the historical record. Rather than continue to use unrealized extremes, the Company moved to 25 percent and 75 percent exceedence levels. "Dry," or 75 percent exceedence level, represents a reasonable lower bound for hydro generation and "wet," or 25 percent exceedence level, represents a reasonable upper bound. ICNU's adjustment should be rejected because the historical data demonstrates that most of the actual outcomes will likely fall between the upper and lower boundaries. (PPL/204, Widmer/28.)

b. Median v. Mean

ICNU contends that computing the mean hydro is the most accurate calculation method, because the mean does not depend on the shape of the distribution and, therefore, may be computed accurately. (ICNU/100, Falkenberg/19.) In fact, the opposite is true. While both median and mean can be calculated accurately, a calculation using the median rather than the mean better defines the central tendency of hydro generation data, since it is not slanted by extremes on either end. (PPL/204, Widmer/29-30.)

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

In order to predict results for any future year, the Company believes the median rather than the arithmetic mean provides the most accurate results. When calculating the mean, values are added, and then divided by the total number of values. As a result, one extreme value on either end could sway the average. When calculating the median, by contrast, all values above the median have the same probability of occurrence (50 percent) as do all of the values below the median. In a small sample, such as 40 measures of the annual hydro generation, the mean can be affected by the magnitude of a single extreme event. By selecting the median rather than the arithmetic mean as the third point and measure of central tendency, there is some assurance of stability in the hydro generation distribution, with changes generally affecting the upper and lower bounds. (PPL/204, Widmer/30.)

Additionally, ICNU's mean hydro adjustment calculation has two flaws. First, ICNU substitutes the "mean" hydro generation impact in the calculation using a flawed linear regression approach. Second, it inappropriately averages the generation of three exceedence levels to determine the "mean" annual hydro generation. The 25 percent and 75 percent exceedence values have equal probability but not equal weight. Using them in a calculation of the mean is not appropriate. One would have to go back and model all the levels of generation to determine the average. (PPL/204, Widmer/30-31.) If ICNU's calculation is corrected to include all the information from ICNU's own analysis, the impact of ICNU's adjustment is zero. (*Id.*)

For all of these reasons, ICNU's adjustment to hydro modeling should be rejected.

7. ICNU's GP Camas Contract Adjustment is Outside the Scope of the TAM.

ICNU's proposed GP Camas contract adjustment should be rejected because it improperly attempts to fold into the TAM proceedings costs that are outside the TAM's scope. This adjustment lowers PacifiCorp's total company NVPC by $0.4 million.

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

Pursuant to PacifiCorp's GP Camas mill contract, which was executed in 1993, the Company built a steam turbine and is recovering the capital investment over the twenty-year operational term of the contract. (PPL/102, Kelly/12.) PacifiCorp's NVPC for the mill include the contract costs of energy for the GP Camas unit as a purchased power expense. They do not include the credit to Other Revenues for the offset of the capital cost recovery and major maintenance cost recovery amounts. Because of this, only the purchase power component of the GP Camas contract is properly updated through the TAM. (PPL/102, Kelly/12.)

ICNU takes the position that the Company "has included the unadjusted contract cost of power it received from GP, but has ignored various offsets it receives from the customer," and that such treatment is "one-sided." (ICNU/100, Falkenberg/8.) ICNU notes that PacifiCorp's cost of power reflects 2008 changes to the contract price, but not to contract offsets, because the offsets are included in "Other Revenue" and are base rate items that are not reflected in the Company's proposed NVPC/TAM price increase. (ICNU/100, Falkenberg/8.)

If the Company had updated the Other Revenues associated with the GP Camas contract in this case, Other Revenue would decrease by $376,498, and the revenue requirement deficiency would increase by the same amount. ICNU's proposal to include both the NVPC and Other Revenue impact of the update to the GP Camas contract would thus increase the Company's forecast costs in this proceeding. (PPL/102, Kelly/13.) This adjustment should be rejected because it is outside the scope of the TAM. (PPL/102, Kelly/11-12.)

V. CONCLUSION

Based upon all of the foregoing, PacifiCorp respectfully requests approval of its proposed 2008 TAM rates, subject to future specified updates. Using PacifiCorp's most

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

current update, this would result in a rate increase of $29.6 million, or 3.2 percent on an overall basis, effective January 1, 2008.

DATED: September 5, 2007.

McDowell & Rackner PC

Katherine A. McDowell

Attorney for PacifiCorp

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in Docket UE 191 on the following named person(s) on the date indicated below by email and first-class mail addressed to said person(s) at his or her last-known address(es) indicated below.

Lowrey R. Brown
Citizens' Utility Board of Oregon
lowrey@oregoncub.org

Melinda J. Davison
Davison Van Cleve, PC
333 SW Taylor, Suite 400
Portland, OR 97204
mail@dvclaw.com

Ed Durrenberger
Public Utility Commission of Oregon
PO Box 2148
Salem OR 97308-2148
ed.durrenberger@state.or.us

Jason Eisdorfer
Citizens' Utility Board
jason@oregoncub.org

Randall J. Falkenberg
RFI Consulting, Inc.
8343 Roswell Rd PMB 362
Sandy Springs, GA 30350
consultrfi@aol.com

Bob Jenks
Citizens' Utility Board of Oregon
bob@oregoncub.org

Jason W. Jones
Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
jason.w.jones@state.or.us

DATED: September 5, 2007

Katherine A. McDowell

Attorney for PacifiCorp

McDowell & Rackner PC
520 SW Sixth Avenue, Suite 830
Portland, OR 97204