Davison Van Cleve PC
Attorneys at Law
TEL (503) 241-7242 ● FAX (503) 241-8160 ● hmt@dvclaw.com
Suite 400
333 SW Taylor
Portland, OR 97204

August 24, 2017

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PACIFICORP, dba PACIFIC POWER
2018 Transition Adjustment Mechanism
Docket No. UE 323

Dear Filing Center:

Enclosed for filing in the above-referenced docket, please find the Cross-Examination Exhibits on behalf of the Industrial Customers of Northwest Utilities.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Haley M. Thomas
Haley M. Thomas

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 323

In the Matter of PACIFICORP, dba PACIFIC POWER, 2018 Transition Adjustment Mechanism.	))))))	CROSS-EXAMINATION EXHIBITS OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

Pursuant to Administrative Law Judge ("ALJ") Sarah Rowe's April 26, 2017 Prehearing Conference Memorandum, the Industrial Customers of Northwest Utilities ("ICNU") submits the following cross-examination exhibits.

Cross-Examination Exhibit	Description
ICNU/300	CUB's Comments from January 23, 2017, regarding Pacific Power TAM Workshops, UE 307
ICNU/301	PacifiCorp's Comments regarding Post-Order Workshops (January 31, 2017), UE 307
ICNU/302	Surrebuttal Testimony of Randall J. Falkenberg on behalf of ICNU (June 27, 2005), UE 170

DAVISON VAN CLEVE, P.C.
333 S.W. Taylor, Suite 400
Portland, OR 97204
Telephone: (503) 241-7242

Dated this 24th day of August, 2017.

Respectfully submitted,

DAVISON VAN CLEVE, P.C.

<u>/s/ Jesse E. Cowell</u>
Jesse E. Cowell
333 S.W. Taylor, Suite 400
Portland, Oregon 97204
(503) 241-7242 telephone
jec@dvclaw.com
Of Attorneys for the
Industrial Customers of Northwest Utilities

Citizens' Utility Board
of Oregon

610 SW Broadway, Suite 400, Portland OR 97205 | 503-227-1984 | www.oregoncub.org

January 23, 2017

Chair Lisa Hardie
Commissioner John Savage
Commissioner Stephen Bloom
Public Utility Commission of Oregon

From: Bob Jenks, Executive Director, Citizens' Utility Board of Oregon

Re: Pacific Power TAM Workshops (Item 2, January 24, 2017 Public Meeting)

Over the last two years, Staff, CUB and other intervenors have challenged Pacific Power's power cost modeling in its TAM. Over this time, Staff, CUB and other parties have contested twenty-nine issues, and lost on twenty-eight. The one issue on which the Commission ruled against the Company was so small that it doesn't actually affect Pacific Power rates. It is, quite literally, a rounding error.

This leaves CUB in a position where we believe that the TAM is fundamentally broken, while the Company believes it is working fine. At the core of CUB's concern is the Company's lack of transparency and the continuous tinkering that are constants with regard to Pacific Power's modeling. CUB participates in a similar process for PGE and notes that PGE's AUT does not suffer from these problems. They are not inherent in complicated power cost models, but reflect Pacific Power's approach.

In the Order from the most recent TAM, the Commission ordered Pacific Power to host a number of workshops relating to some of the TAM's continuous issues and has ordered the parties to the case to participate in those workshops. CUB appreciates these workshops and believes they can be helpful — though we do not believe they are sufficient to solve the problems relating to the TAM.

However, CUB is concerned that the Company will approach these workshops as a compliance obligation rather than as a chance to collaborate with the parties and resolve some of the outstanding issues.

Workshop 1: Jim Bridger fueling strategy.
Last week's first workshop reinforced CUB's concerns that the Company's is approaching these workshops as a compliance requirement which it is obligated to host, and is not serious about collaborating with the parties to address concerns related to the TAM.

The Commission Order requiring the workshops was signed on December 20, 2016. CUB heard nothing about the first workshop, until Pacific Power notified the parties on January 3 that the workshop would be held on January 12 in Portland. I had meetings in Salem that day as did most of CUB's regulatory staff. I contacted the Company to let them know that I was interested in attending and asked them to consider moving the meeting or locating it in Salem, which would allow CUB to participate in some (but not all) of the meeting. The answer from the Company was simple. No, they would not consider accommodating CUB. I was told that this was the only date that was possible before the Commission Public Meeting on January 24 that would accommodate Idaho Power. I pointed out that Idaho Power was not a party to the case; that it was the parties to the case that were ordered to participate in the workshops; and that CUB can only comply with the Commission order to participate if the Company accommodates our schedule. In addition, I told the Company that I was well aware of the fact that this workshop needed to be held before the January 24th Public Meeting. I told the Company that I was planning on attending this public meeting. Still the Company made no effort to accommodate our schedule — the best I got was a promise to send out the slide deck to us before the workshop and an offer to brief me on what happened at the workshop after it was concluded.

While Pacific Power would not accommodate CUB, the weather intervened. The workshop was canceled due to snow. Knowing that I was coming to this public meeting may have influenced the Company to show some flexibility in rescheduling and in the end there was a date in January that seemed to accommodate both Idaho Power and CUB.

If not for the snow storm and this Public Meeting, it is doubtful that CUB could have effectively participated.

Regarding the content of the workshop, we spent the first 15 minutes discussing whether the slide deck was highly confidential or only confidential in order to determine who could see it. After the Company agreed to designate it as only confidential so all could see it, the Pacific Power team passed out the slide deck, which did not have any actual data in it. It is a stretch to call it confidential and there is no basis for its original designation as highly confidential.

In the workshop, the Company provided a very, very high level description of the four fueling strategies for its Jim Bridger plant that the Company will evaluate over the next year using the scenarios from the IRP and that any changes to fueling would then take place after a three-year transition period.

In the interim the Company will have to deal with two expiring contracts, and these new coal procurement agreements (with new minimum take-or-pay requirements) may well enter the TAM in the October update without any real opportunity for a meaningful prudence review by the parties due to the condensed procedural timeline of that period.

In addition, the high level summary of the four options all identified, but did not quantify, additional capital investments associated with that strategy. At the same time later this week, PacifiCorp will have an IRP workshop that includes its confidential Regional Haze compliance plans. It is unclear whether the level of capital investments in the fuel plan are significant enough that they should be included in the Regional Haze analysis. The Company did not know how this coal strategy interrelated to the Regional Haze compliance study.

CUB asked the Company to hold additional workshops as it evaluates these strategies and to provide some actual data associated with them, prior to selection of a strategy by the Company.

The workshop provided a reasonable overview of how the Company will go about evaluating it post-2022 fueling strategy and was helpful. However, because the workshop was at such a high level and contained no comparative cost-based analysis of the fueling options, it had little effect on the ability of parties to evaluate the prudence of PacifiCorp's Bridger fueling strategy. But it was a start.

Future Workshops.
CUB believes the additional workshops can help, but they must be a collaborative workshop, not a compliance workshop.

DART Workshop.
The primary direction for this workshop is for the Company to explain its modeling and to allow parties to present their alternative approaches, though parties may also use the workshops to discuss whether any adjustments to PacifiCorp's existing methodologies may be appropriate. The Company has already rejected our alternative modeling approaches – it prefers the DART which added $8 million to rates its first year and $9 million last year.

There is an issue that can easily be resolved, however. CUB's most significant objection to the DART is its use of actual non-normalized system balancing sales as an adjustment to a normalized forecast of power costs. Two years ago, the Company asserted that by using 3 years of data, that the non-normalized balance purchases would not be a problem. This year, they argued that the issue had already been decided. But what they haven't done is actually show the effect non-normalized system balancing purchases on DART model. CUB believes that we can use this workshop to conduct some scenario analysis to see what effect non-normalized events such as weather excursions, thermal outages and poor hydro conditions can have on the mechanism.

This is not difficult, since the last two months have provided us with the data to see what a cold weather event will have on the mechanism. There is little doubt that system balancing purchases with a delivery period of less than a week increased significantly during the last two months. It would be constructive and illuminating to take December 2016 and January 2017 system balancing purchase volumes and substitute them for a December and January already included in the model and we will see if this has a significant effect on the DART.

If there is no significant impact, this is good news and CUB can stop raising this objection

If there is a significant impact of using non-normalized actual data, we can then debate whether this is a reasonable outcome. The purpose of the DART was to recover system balancing costs that the Company is systematically not recovering. While it is clear that the Company had a greater volume of system balancing purchases this winter, it is not clear that those purchases lead to a greater volume of unrecovered costs. Customers' bills have skyrocketed this winter. With inverted residential rates (higher rates for customers who use more than 1000 kWh in a month) most of the additional heating load is billed at the higher tailback rate and with the Company's fixed costs covered at normal usage, most of this revenue is available to cover variable power costs. Even with abnormally cold weather, on peak prices have largely stayed below 4 cents/kWh.

One reason that the PCAM is an appropriate place to deal with recovery of non-normalized power costs because it has an earnings test, so both costs and revenue are recognized.

The dispute over the ongoing impact of non-normalized data in the TAM has been an issue the last two TAMs but now that we have some non-normalized data we can solve it in this workshop. If the evidence shows that actual non-normalized purchased do not have a significant effect on the DART, CUB will have no reason to assert otherwise.

Tinkering and Transparency.
As originally envisioned, the TAM was to be a straightforward process that would use the GRID model to update a handful of variable power costs:[1]

Forward Price Curve
Forecast Loads
Normalized Hydro Generation
Forecast Fuel Prices
Contract Update
Heat Rates, Forecast Planned Outages and De-rates
Wheeling Expenses
New Resource Acquisitions (New Wholesale Sales and Purchases)
State Allocation Factors

First, it should be noted how few of the contested issues come from this list. The problem with the TAM is not a disagreement with what should be updated or even what those updates should be, the problem is that the underlying models (GRID, DART, EIM benefits studies) are constantly in motion and the Company regularly fails to notify parties as it changes models, even where the TAM Guidelines require such notice or even when the Commission has expressly told the Company not to make changes in modeling.

This is where the real contrast with PGE exists. First, PGE's power cost model is fixed between general rate cases. Second, PGE provides parties with a "Step Log" which identifies every modeling change, and every new input to the model. A party can run through the Step Log and see every change that has happened since last year's modeling of power costs, and the impact of those changes. It is transparent.

[1] UE170 PPL/Omohundro/11-12.

PacifiCorp does not do this. Even when they are required to disclose modeling changes, they regularly fail to do so. In the 2017 TAM the Company changed how it modeled EIM benefits between its Opening and Rebuttal Testimony without including this change on PacifiCorp's List of Corrections or Omissions which is the proper notice required by the TAM Guidelines.[2]

For an analyst, PacifiCorp's approach is troubling. Many of the work papers involve spreadsheets with dozens of tabs and hundreds of cells. To be in the middle of reviewing work papers and discovering that it is not performing as expected, sets the analyst back. He or she now must go back and figure out what is wrong. Sometimes this can take hours or days. It may involve contacting the Company and it can require additional data requests which take up to two weeks to be answered. In a compressed schedule time is essential to ensure proper and thorough analysis.

Sometimes the Company will describe the new approach in testimony without stating that it is a change in methodology, but that is limited help. Most of testimony, for example, is explaining modeling that has not changed. Requiring the analyst to go back and compare testimony and work papers in one filing to the previous filing to determine what has changed is unfair, particularly since the guidelines are designed to ensure transparency by requiring the utility to disclose and identify changes.

This lack of transparency and constantly changing models can make it difficult to provide solid evidence supporting criticism of the TAM. If parties appear confused, it is because PacifiCorp's lack of transparency is confusing.

Fixing the TAM.

The real question is: How do we fix the TAM? How do we get the tinkering and transparency issues fixed? This is a real and significant problem. Because the Company wins on nearly all contested issues, it has no incentive to improve the process. To PacifiCorp, there is nothing broken and therefore there is nothing to fix.

First, to ensure that the workshops that have been ordered by Commission help the transparency problem, the Company should be required to disclose all changes that it will be making to its models in the workshop. Currently, it is not even clear if the workshops represent last year's methodology or will be a preview of what is filed in April.

Second, we should require a process that is more like PGE's. The modeling in the TAM should not be continually evolving, where it even changes between opening and rebuttal testimony. All modeling (GRID, DART, EIM) should be locked down most years so we are only dealing with updates. And PacfiCorp should be required to institute a Step Log that identifies all modeling changes, all updates, and all adjustments. The TAM is intended to be a streamlined docket—it has not followed that model in recent years.

Third, when the Company violates its transparency requirements, the Company needs to be accountable. When modeling changes are prohibited, the Company must held accountable for

---

[2] UE 307 – CUB's Response Brief 13

making modeling changes. Ignoring a prohibition on modeling changes if the modeling change seems reasonable is not helpful since the Company will always claim that its modeling changes are reasonable. If the Company changes a model without identifying that change then the Company should be held accountable.

Fourth, the Company should be prohibited from introducing new modeling changes in rebuttal testimony — unless those changes come in response to testimony of parties or are the result of a stipulation.

Conclusion
CUB hopes these comments are not viewed as sour grapes because we have lost every issue we have contested with regards to PacifiCorp's power costs over the last 2 years. Our goal is not to resurrect and litigate issues that have already been decided. Nothing would be better than reducing the number of contested issues and getting to a place where the TAM process was achieving fair results from a transparent and understandable process.

But from our perspective, the TAM is broken and while the workshops can help, they are not enough.

Sincerely,

Bob Jenks
Executive Director
Citizens' Utility Board of Oregon
610 SW Broadway, Ste. 400
Portland, OR 97205
(503) 227-1984 x 15
bob@oregoncub.org

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

January 31, 2017

VIA ELECTRONIC FILING

Commission Chair Lisa Hardie
Commissioner John Savage
Commissioner Stephen Bloom
Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, Oregon 97301-3398

**RE: UE 307 Post-Order Workshops
Item 2, January 24, 2017 Public Meeting**

Dear Commissioners:

Thank you for addressing Staff's report on Pacific Power's Jim Bridger coal plant long-term fuel supply plan collaborative at the public meeting of the Public Utility Commission of Oregon (Commission) on January 24, 2017. Pacific Power received the Citizens' Utility Board of Oregon's (CUB) letter on this subject late on January 23, 2017, so the Company was unable to provide a complete response at the public meeting. PacifiCorp is submitting its response now to clarify several points CUB raised in its letter.

First, CUB states that the Company's Transition Adjustment Mechanism (TAM) is broken because CUB and other parties have lost most of the issues raised in the last two TAM proceedings. The fundamental test of whether the TAM is working, however, is whether it produces an accurate net power cost (NPC) forecast, not the number of adjustments approved. The evidence in docket UE 307 was that the Company has increased the accuracy of the forecast NPC in the TAM (*i.e.,* the Company's NPC under-recovery has decreased), in part based on modeling changes that CUB and others contested in the last two TAMs. The Commission's approval of the Company's latest TAM filings without major adjustments demonstrates that the TAM is working to set NPC at a fair and reasonable level, not the opposite.

Second, CUB expresses concern that PacifiCorp is approaching the TAM workshops as a compliance obligation instead of a chance to collaborate on outstanding issues. The Company views the workshops as an excellent opportunity to freely share information, present analysis, and develop potential new solutions to key modeling issues in the TAM. PacifiCorp has a strong interest in working with CUB and other stakeholders to avoid another litigated TAM proceeding and plans to engage fully in the collaborative process. The Company regrets the initial scheduling complications for the first workshop which led to CUB's concerns, and is pleased that a mutually agreeable date was available in the end.

Third, perhaps because these issues are inherently complex, CUB's comments do not accurately describe the alternative proposals the Company presented at the January 20, 2017 workshop for completing the Jim Bridger plant long-term fuel plan. The meeting was a preliminary step, where parties were able to request additional details on the options presented by Pacific Power, provide input for additional options, and propose different analyses to evaluate the alternatives. Specifically, the Company presented two possible approaches. First, the Company proposed to file a long-term fuel supply plan based on the four scenarios it has been evaluating. The Company sought to encourage feedback by presenting the scenarios as high-level proposals, not as completed analyses. This is consistent with the Commission's direction that the parties meet in workshops to discuss the "information and analyses needed to meaningfully evaluate PacifiCorp's long-term fuel supply plan in future [TAM] proceedings." Order No. 16-482 at 24. The Company was clear that it was far enough in its analysis of these basic scenarios, however, to complete a new fuel plan quickly and file it with the Commission within the next two months.

PacifiCorp's alternative proposal was to broaden and update its planning assumptions and scenarios relying on the Company's 2017 Integrated Resource Plan (IRP), including the fuel requirements reflected in the Company's latest environmental compliance planning. The Company will file the IRP at the end of March. While incorporating the new information and scenarios will delay completion of the long-term fuel plan until late 2017, this approach avoids the likely need to update a plan that does not reflect the information presented in the latest IRP.

Parties spent the bulk of the workshop considering these two different approaches, with general support for the proposal to prepare a more up-to-date and comprehensive plan tied to the IRP. The Company identified and the parties discussed how to approach the third-party contracts related to Jim Bridger fuel supply that are up for review in 2017 during preparation of the long-term fuel plan. Staff offered constructive and detailed feedback, proposing various different assumptions and sensitivities for the Company to consider in developing the long-term fuel plan.

The Company appreciates that CUB ultimately agrees that this initial workshop was helpful and that the Company provided a reasonable overview of its proposed planning process. The Company hopes that these sentiments, along with the clarifications provided in this letter, will provide a solid foundation for the collaborative process ahead.

Fourth, CUB provided comments on the day-ahead and real-time balancing adjustment. The parties are working on scoping the first workshop on this issue and others flagged in Order No. 16-482, which will be held in February.

Fifth, CUB raised concerns about the transparency of the TAM. CUB is incorrect that the Company has no incentive to improve the TAM to respond to parties' concerns. The Company has a strong interest in streamlining the TAM and avoiding contentious litigation. The collaborative development and refinement of the original TAM Guidelines demonstrates that there is a shared interest in getting the TAM process right. As I mentioned at the Commission's public meeting, the Company supports adding CUB's proposals on the transparency of the TAM, some of which are drawn from Portland General Electric Company's Annual Update Tariff process, to the workshop discussions. Because of the complexity of PacifiCorp's system, however, the Annual Update Tariff modeling approaches and processes may not be transferable to PacifiCorp.

CUB also claims that the Company's NPC model is constantly changing without notice to the parties, even when changes are prohibited by the Commission. The Company disagrees and notes that the Commission has never found that the Company improperly updated its NPC modeling in the TAM or failed to provide information on modeling changes. Nevertheless, the Company wants to ensure that CUB has the tools it needs to analyze TAM filings and remains committed to providing CUB information and analytical support. To this end, the Company recently invited CUB staff to an onsite visit and training on the Generation and Regulation Initiative Decision Tools model in advance of the TAM workshops and the 2018 TAM filing.

Finally, the Company agrees with CUB's conclusion in its letter that "[n]othing would be better than reducing the number of contested issues," with a TAM that produces "fair results from a transparent and understandable process." With full and open engagement from all parties, the Company is optimistic that the TAM workshops can help achieve these goals.

Sincerely,

R. Bryce Dalley
Vice President, Regulation

Enclosures

cc: Service List UE 307

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 170

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

SURREBUTTAL TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

JUNE 27, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350. I am the same Randall J. Falkenberg who filed direct testimony in this case.

Q. WHAT IS THE PURPOSE OF THIS SURREBUTTAL TESTIMONY?

A. I will reply to the rebuttal testimony of PacifiCorp witnesses Omohundro, Taylor, Tallman, Widmer, and Wrigley. This testimony will address issues related to the jurisdictional allocation of Existing Qualifying Facility ("QF") Contracts, new resources, Resource Valuation Mechanism ("RVM") power cost issues, and the Georgia-Pacific ("G-P") Camas contract.

<u>Existing QF Contracts</u>

Q. WERE YOU INVOLVED IN THE MSP PROCESS AND UM 1050?

A. Yes. I was the Industrial Customers of Northwest Utilities' ("ICNU") witness in UM 1050, and I have participated in many Multi-State Process ("MSP") meetings and workshops over the past three years. I am continuing to participate in the MSP meetings regarding load growth, the Hybrid proposal, and the implementation of the Revised Protocol.

Q. HAVE YOU REVIEWED THE TESTIMONY OF PACIFICORP WITNESS TAYLOR CONCERNING THE ALLOCATION OF EXISTING QF CONTRACTS?

A. Yes. Mr. Taylor does not agree that the Desert Power, Kennecott, Tesoro, and US Magnesium contracts qualify as Existing QF Contracts in the Commission-approved Revised Protocol. Mr. Taylor's arguments ignore the most important language actually contained in the document.

Q. MR. TAYLOR RELIES ON THE LANGUAGE IN SECTION II OF THE REVISED PROTOCOL ("PROPOSED EFFECTIVE DATE") TO RATIONALIZE

THAT THE FOUR CONTRACTS WERE NEW RATHER THAN EXISTING CONTRACTS. PLEASE COMMENT.

A. Mr. Taylor views June 1, 2004, as the "effective date" of the Revised Protocol based on the language of Section II. However, "effective date" is not a defined term in the Revised Protocol. Thus, one must try to interpret its meaning based on the intentions of the parties.

Q. DOES ANYTHING IN SECTION II ADDRESS QF CONTRACTS?

A. No. The language in Section II does not indicate that the *proposed* effective date has any relationship to the designation of Existing QF Contracts; it merely suggests that PacifiCorp will use the Revised Protocol in cases filed after June 1, 2004. Had the parties intended that Existing QF Contracts be defined as those that were executed before June 1, 2004, it would have been a very simple matter for the definition of Existing QF Contracts to have stated so. Instead, the definition of Existing QF Contracts provides as follows:

> **"Existing QF Contracts"** means Qualifying Facility Contracts entered into prior to the effective date of this Protocol, but not such contracts renewed or extended subsequent to the effective date of this Protocol.

Re PacifiCorp, OPUC Docket No. UM 1050, Order No. 05-021, Attachment A at 50 (Jan. 12, 2005). This clearly suggests that the parties did not intend for Existing QF Contracts to be defined as those that were entered into prior to June 1, 2004. This telling point belies all of Mr. Taylor's arguments.

It is also ironic that Mr. Taylor would rely upon the "Proposed Effective Date" language of Section II, while completely ignoring the far more significant language of Section XIII D (emphasis added):

> *The Protocol shall only be in effect for a State upon final ratification by its Commission.* Absent the final adoption of the Protocol, the Company will continue to bear the risk of inconsistent allocation methods among the States.

This language clearly indicates what common sense tells us: the Revised Protocol could only be in effect for a state *after* adoption by its Commission, not before. Certainly before final adoption, the document is also "absent the final adoption." Consequently, the Company bears the risk of inconsistent allocation methods prior to final adoption. As the four contracts in question were all entered into during the period before (or absent) final adoption of the Revised Protocol, they should be treated as Existing QF Contracts.

Q. DOES THE LANGUAGE IN SECTION XIII MAKE ANY SENSE UNDER MR. TAYLOR'S THEORY?

A. No. Under Mr. Taylor's novel theory there was no need for the language from Section XIII, quoted above, to have been included in the document. If June 1, 2004, was the effective date, why did the parties insist that the document say it would not be effective for a state until final adoption by its Commission? Why didn't they define the effective date as June 1, 2004?

Q. DOES SECTION II ACTUALLY STATE THAT JUNE 1, 2004, IS THE "EFFECTIVE DATE?"

A. No. It merely calls June 1, 2004, a "*proposed* effective date." If nothing else, this suggests that adoption of that date was not a requirement for ratification. Further, there was nothing in the Commission's Order in UM 1050 indicating that it had specifically approved of the "*proposed* effective date." Nor did the Commission indicate in the Order that it would supersede the language of Section XIII with the *proposed* effective date language of Section II. Since UM 1050 was not even submitted to the Commission for decision until long after June 1, 2004, it should be obvious that the June 1, 2004, "*proposed* effective date" was both meaningless and impossible by that time.

Q. MR. TAYLOR TESTIFIES ON PAGES 3-4 THAT IT WAS EXPECTED THAT FINAL RATIFICATION OF THE REVISED PROTOCOL WOULD OCCUR AFTER ITS EFFECTIVE DATE. PLEASE COMMENT.

A. This is nonsensical on its face. The document itself says it is not effective for a state until final ratification by its Commission. Mr. Taylor focuses on what he would like for the document to have said, rather than what it actually says.

Q. IN THE SAME PASSAGE, MR. TAYLOR INDICATES THE COMPANY REQUESTED A JUNE 1, 2004, EFFECTIVE DATE BECAUSE THE COMPANY WAS PLANNING ON FILING RATE CASES PRIOR TO APPROVAL OF THE REVISED PROTOCOL BY THE VARIOUS STATES AND WANTED TO USE THE REVISED PROTOCOL. PLEASE COMMENT.

A. His comments concerning the Company planning to use the methodology in rate cases it filed before the approval of the Revised Protocol may be true, but they also are irrelevant. There was nothing to stop PacifiCorp from filing rate cases in *any* state using *any* method it preferred before or after June 1, 2004.

Further, Mr. Taylor should recall that the document was being negotiated from March to May 2004. At that time, the procedural schedule in UM 1050 was fairly "tight," suggesting a decision might have been obtained much more quickly than ultimately occurred. During the discussions, the Company was very mindful of the fact that it planned to file an Oregon rate case in the near future. This was another time pressure that drove the process to some extent. At the time, there was a concerted effort to expedite the discussion process to come to a quicker resolution. Perhaps by expediting the process to obtain quick approval of the document, the Company lost sight of the implications of the language in Section XIII. In the end, it matters little, because the language of the document is what was agreed upon by parties in four states and approved by the Oregon Commission in January 2005.

Finally, it was impossible for all aspects of the Revised Protocol to be retroactively effective to June 1, 2004. For example, the Revised Protocol requires creation of a Standing Committee. That process has just now begun. It most certainly was not "effective" retroactive to June 1, 2004. Neither can the Company simply decide unilaterally that as of June 1, 2004, the Commission had adopted the Revised Protocol, making it effective for all QF contracts entered into after that date.

Q. HAS THE COMPANY ALREADY DECLINED TO MAKE THE REVISED PROTOCOL RETROACTIVELY EFFECTIVE IN OTHER STATES?

A. Yes. PacifiCorp filed a rate case in Washington in late 2003 under the Original Protocol method. In the course of the case it was revealed that the Company would have had a lower revenue requirement in Washington under the Revised Protocol than under the Original Protocol. However, in that case, the Company opposed ICNU's proposal to compute Washington revenue requirements using the Revised Protocol (with certain adjustments). In September 2004, a decision in Washington was rendered, based on a Stipulation that was premised upon the Original Protocol.

Q. DID THE PACIFICORP FILING IN THE UTAH CASE TREAT THE US MAGNESIUM CONTRACT IN THE MANNER PROPOSED IN OREGON BY MR. TAYLOR?

A. No. The US Magnesium contract was treated as an "*Existing QF Contract*" in the Company's original Utah filing. In Oregon, the Company filed a rate case a few months later, but considered the very same contract a "*New QF Contract*." While the Company subsequently renegotiated the contract and amended its filing in Utah, the contract included in the Oregon filing is, in fact, the original contract as filed in Utah. This is obvious because the renegotiated US Magnesium contract has no demand charges, while the original contract did. In both the Utah and Oregon rate case filings, the US

Magnesium contract modeled in the power cost studies contains the same demand charges ($326,750 per month) in the months that the two test years had in common (January to March 2006). The same is true of the February 2005 update. To my knowledge, this contract is still the basis for the Company's ECD calculations. PPL/403, Taylor/1.

Q. ARE THERE ANY OTHER REASONS THAT THIS ISSUE SHOULD BE OF CONCERN TO THE COMMISSION?

A. Yes. In my testimony in UM 1050, I pointed out that PacifiCorp had provided rate caps to guarantee that Utah revenue requirements under the Revised Protocol would not differ significantly from Utah's preferred rolled-in method. This raises a "red flag," because it implies that the Company would now have an incentive to "side" with Utah in any future disputes concerning the Revised Protocol. Because the Revised Protocol has already resulted in Utah revenue requirements exceeding the stipulated rate cap, it is unlikely that the Company would be able to recover the costs of these contracts in that state if they are treated as Existing QF Contracts. This means that the Company is not in a position to be "an honest broker" in situations of this nature. This is exactly the type of situation I warned of in my UM 1050 testimony. This clearly is not a case where the Commission can view the Company as an impartial arbiter between the States.

Q. MR. TAYLOR HIGHLIGHTS THE LANGUAGE OF THE VARIOUS QF CONTRACTS THAT DESIGNATES THEM AS "NEW CONTRACTS" UNDER THE TERMS AND CONDITIONS OF THE REVISED PROTOCOL. PLEASE COMMENT.

A. There are multiple flaws with this argument. *First*, Mr. Taylor assumes that the Oregon Commission is somehow bound by self-serving agreements made between PacifiCorp and QF developers in other states. *Second*, the Oregon Commission never had the opportunity to approve the contracts in question, as they were only submitted for approval to the Utah Commission. *Finally*, the fact that PacifiCorp felt it necessary to include such language in such contracts indicates that perhaps they themselves realized this was an issue that might be problematical for the Company. I fail to see how any of this provides a compelling reason for the Commission to adopt Mr. Taylor's position.

Q. ON PAGE 5, MR. TAYLOR TESTIFIES THAT IT WOULD BE UNREASONABLE FOR ANY STATE TO BE ABLE TO ALTER ITS ALLOCATION OF QF CONTRACTS BY THE TIMING OF ITS APPROVAL OF THE REVISED PROTOCOL. PLEASE COMMENT.

A. The language certainly does that for all states. However, the language in question gave Utah the incentive for an early approval of the Revised Protocol. Utah could have been able to reduce its potential impact from the allocation of Existing QF Contracts by approving the document sooner rather than later. Ultimately, Utah did not approve the Revised Protocol until December 2004, even though the stipulation in that state was signed in May 2004. Utah certainly had some opportunity to mitigate the impact of Existing QF Contracts. Because Utah was the state that precipitated the "break" in the prior jurisdictional allocation method, I believe other states waited until Utah approved the Revised Protocol. Certainly, there would have been no reason for other states to adopt the Revised Protocol if Utah had turned it down, with all of the protections of the stipulation in that state.

Q. ON PAGES 6-7, MR. TAYLOR SUGGESTS THAT THE OREGON PARTIES WHO SIGNED THE STIPULATION UNDERSTOOD THE IMPACT OF THE EXISTING VS. NEW QF ISSUE. PLEASE COMMENT.

A. Mr. Taylor references studies in which the Existing QF Contracts were modeled during the MSP process. Whatever the results of those studies, they have no bearing on the language of the document, which is controlling. Indeed, the Company has been clear that it was never willing to guarantee Oregon any of the "savings" projected in such studies related to the Hydro Endowment. It cannot now claim that these model runs are more significant than the Revised Protocol document itself. Ironically, the treatment of the US Magnesium contract in those studies did not prevent the Company from filing its Utah rate case with the contract modeled as an Existing Contract, as noted above.

Q. CAN THE OREGON COMMISSION ADOPT THE COMPANY'S PROPOSAL AND REMAIN FAITHFUL TO THE TERMS OF THE REVISED PROTOCOL?

A. No. If the Commission wishes to reclassify the four contracts as "New Contracts," it would be necessary for it to bring the matter before the Standing Committee. The other four states that approved the document would have a say in the matter. While Utah obviously might prefer PacifiCorp's interpretation, Wyoming and Idaho may not. Even if one believes there is some ambiguity in the meaning of the document, the Commission should follow the interpretation that makes the most sense. It could then take the matter before the Standing Committee and, if it wishes, propose an amendment to the document to allow PacifiCorp's interpretation to be implemented in the future. Because it appears this issue may not have any impact on Utah's rates for a number of years, going through the Standing Committee is a logical option.

Shortly, the Standing Committee will be considering issues such as structural protections for load growth and seasonal allocations. The definition of Existing QF Contracts is an issue that could be raised in the context of those discussions if the Commission so desires.

New Resources

Q. MR. TALLMAN TESTIFIES THAT WEST VALLEY COSTS HAVE BEEN REFLECTED IN RATES SINCE 2002 AND THAT GADSBY'S COSTS HAVE BEEN INCLUDED IN RATES SINCE 2003. IS THIS RELEVANT TO THE ISSUES OF PRUDENCE OR THE MARKET VALUE RULE?

A. No. These costs were included in rates as the result of stipulations in UE 134 and UE 147. As such, there is no precedent established by those cases. Further, as noted by Mr. Tallman, Commission Order No. 02-657 indicated that the Commission did not make a prudence finding regarding the West Valley lease in UI 196. Consequently, the prudence of West Valley has never been established because the Commission never decided the issue in UE 134 either, owing to the settlement in UE 147.[1/] In the end, there is no Commission precedent concerning prudence or the market value rule for Gadsby and West Valley.

Q. MR. TALLMAN HAS INCORPORATED PACIFICORP'S TESTIMONY FROM UE 134 INTO HIS REBUTTAL. DOES ICNU WISH TO INCORPORATE ITS UE 134 TESTIMONY INTO THE RECORD AS WELL?

A. For completeness of the record, I am including my direct testimony from UE 134 as Exhibit ICNU/112. Most of the information contained in my rebuttal testimony in UE 134 was condensed into my direct testimony in this proceeding, so I do not include it here.

[1/] At the time of the settlement in UE 147, the decision in UE 134 was still pending. In the UE 147 settlement, the parties agreed to drop the matter of West Valley in UE 134, without prejudice.

Q. MR. TALLMAN DISPUTES YOUR CONTENTION THAT PACIFICORP SHOULD HAVE SOUGHT BIDS TO REPLACE WEST VALLEY IN RFP 2003-A. ARE HIS ARGUMENTS PERSUASIVE?

A. No. In effect, Mr. Tallman is arguing that West Valley is a short-term resource (a three-year option) that should only be compared to other short-term options (i.e., as was done in RFP 2004-X).

This shows the fundamental problem of West Valley in that the Company simply *assumes* the prudence question away by defining West Valley as a "short-term" resource. Rather than comparing the resource to a long-term asset, the Company only compared it to short-term resources. I discussed how this biased the results of RFP 2004-X in my direct testimony. However, there is no basis for assuming that the Company actually needs "short-term" resources more than "long-term" resources in the first place, or for determining the optimal mix of long or short-term resources PacifiCorp should have in its portfolio. Likewise, Mr. Tallman does not offer any evidence to demonstrate that a long-term resource was not more economic than a plan with a "short-term" West Valley. It was purely arbitrary for the Company to make that designation in the first place. Mr. Tallman's response to this issue amounts to little more than saying, "West Valley is prudent because we say it is prudent."

Q. MR. TALLMAN CONTENDS THAT IT IS NOT PROPER TO COMPARE WEST VALLEY TO A "CURRANT CREEK CLONE" BECAUSE THERE WERE NO OTHER 2005 RESOURCES THAT BID WITH ECONOMICS COMPARABLE TO CURRANT CREEK. PLEASE COMMENT.

A. Mr. Tallman misunderstands my analysis. I compared the cost of West Valley to the combustion turbine portion of Currant Creek. There is nothing special about the Currant Creek combustion turbine that gives it a substantially lower cost than other resources. It provides a reasonable basis for estimating the cost of a replacement for West Valley.

Further, the Company itself could have built additional capacity at the Currant Creek site for an even lower cost, because it would have been an "incremental" unit. Thus, my estimate of the cost of replacing West Valley is a reasonable alternative for the Company to have considered.

Finally, there were other resources with overall costs that differed little from Currant Creek in RFP 2003-A. It was only the biased bid evaluation method used by the Company that made Currant Creek appear to be much more economical than the other options.

Q. ARE THERE POLICY REASONS WHY THE COMMISSION SHOULD NOT CONSIDER THE COMPANY'S REQUEST FOR A WAIVER IN THE CONTEXT OF THIS CASE?

A. The Commission should reject the request for waiver because it has not been appropriately raised in this case. Aside from the troubling procedural aspects of requesting a waiver from Commission rules at the "eleventh hour," the Commission should consider using the market value rule as a tool to protect Oregon's interest in situations involving new resources constructed in other states.

Q. PLEASE ELABORATE.

A. Under current law and practice, the Oregon Commission has little ability to address the construction of plants in other states. Currant Creek, for example, was certified in Utah, not Oregon. The Oregon Commission had no opportunity to approve or deny PacifiCorp's decision to build Currant Creek once it was certified. While the Commission always has authority to make a prudence disallowance in the context of a rate case, it can only do so in an "after the fact" proceeding. Even if a Commission questioned the prudence of a new plant, there is a natural reluctance to impose a disallowance on a plant after it has been completed. Judicious use of the "market value rule" would enable the Oregon Commission to pass judgment on new resources <u>before</u> construction begins. This would enable the Commission to ensure that only necessary and economical resources are added to the PacifiCorp mix.

Q. HOW WOULD THIS PROCESS WORK?

A. Ideally, the Company would file a case requesting a waiver from the market value rule at the time it files for certification of the resource. The Oregon Commission could then provide a waiver for new resources only if it agreed the new resources were needed, and were the least cost option. In this manner the Commission could play an active, rather than passive, role in the resource selection process. It could also provide a warning against plant construction in cases where prudence has not been demonstrated.

Q. WHILE YOUR PROPOSAL MAY BE INTERESTING, TO THIS POINT IT HAS NOT BEEN THE PRACTICE OF THE COMMISSION. PLEASE COMMENT.

A. True enough. However, this proposal is no more unusual than PacifiCorp requesting a waiver from the Commission's rule only after it has begun construction of a new power plant and requested rate treatment for it. Given the high financial stakes, it was imprudent for PacifiCorp to have begun construction of Currant Creek without first obtaining a waiver from the Oregon Commission. Effectively, the Company has taken full rate treatment from the state of Oregon for granted, in spite of the Commission's market value rule.

Q. WHAT DO YOU PROPOSE BE DONE NOW?

A. The Commission should follow the market value rule in this case.

Q. UNDER WHAT CONDITIONS SHOULD A WAIVER BE GRANTED?

A. The Commission should not grant a waiver from the rule unless it is satisfied that the new resources are needed and are the least cost option. The Commission should also determine if the bidding process used was reasonable, and whether it meets the Federal Energy Regulatory Commission's "above suspicion" standard in the case that the Company or its affiliates ended up as the "winning bidder." ICNU will elaborate on the legal aspects of the waiver issue in its briefs in this case.

Q. MR. WRIGLEY DISPUTES YOUR GADSBY CT ADJUSTMENT ON THE BASIS THAT CUSTOMERS WERE NEVER CHARGED FOR THE PEAKER RENTAL FEES THAT WERE SUBSEQUENTLY AVOIDED BY THE GADSBY CT PURCHASE FROM GENERAL ELECTRIC ("GE"). PLEASE COMMENT.

A. Whether ratepayers were charged or not for the rental fee is irrelevant. PacifiCorp chose its test years in various rate cases, and also chose to exclude the peaker rental fees from its excess power cost deferral (in UM 995). By making different choices, the Company might have been able to recover the peaker rental fees. However, the basis for my adjustment is tied to the fact that the Company would have saved itself $7.5 million through its negotiations with GE for the Gadsby CT equipment. Mr. Wrigley actually confirms that the Company stood to retain this amount because, at the time, the rental fees were not reflected in rates.

Q. MR. WRIGLEY TESTIFIES THAT PACIFICORP DID NOT HAVE A CONFLICT OF INTEREST IN ITS NEGOTIATIONS RELATED TO THE GADSBY TRANSACTION WITH GE. PLEASE COMMENT.

A. Mr. Wrigley's testimony is hardly persuasive. While he contends that PacifiCorp's interest was in getting "the best deal for customers," he offers no evidence as to what alternatives GE offered PacifiCorp. He only argues that GE might have preferred to waive the rental fee, rather than reduce the price of the peakers. He offers no evidence as to what GE's negotiating stance was, or whether it was GE or PacifiCorp who first made this proposal.

Q. HOW HAVE REGULATORS IN OTHER STATES ADDRESSED THIS ISSUE?

A. The last two Utah rate cases were settled, so there is no precedent established. However, the Utah Staff has supported a similar disallowance as shown in the following excerpt from the direct testimony of a Utah Division of Public Utilities ("DPU") witness in the most recent Utah rate case:

> **Q.** Please explain the Gadsby Lease Waiver Adjustment.
>
> **A.** When PacifiCorp applied for a certificate to build the Gadsby units in Docket No. 01-035-37, Company witnesses testified that the decision to build the combustion turbines at Gadsby was preferable over other available alternatives. J. Rand Thurgood testified for the Company that the Company's decision to install General Electric LM 6000 gas turbines was based in part upon: "…the economic benefit PacifiCorp and its customers would realize from General Electric's (GE) agreement to waive the additional fixed cost obligation to lease the temporary mobile gas turbines for another five months." Mr. Thurgood further testified that: "GE's agreement to release the Company from its lease obligation associated with an additional five months rental for the mobile gas turbines has a net impact of reducing 2002 operating expenses by $7.5 million. Simplistically, this has the impact of reducing the effective capital cost equivalent for this particular project to approximately $608/kW." When the Company compared the GE LM 6000 units with other alternative generating options for the Gadsby addition this amount was used.
>
> However the cost comparison provided by Mr. Thurgood showed that the $/Mwh cost of four other options was close enough to the selected GE LM 6000 alternative that they may have been competitively preferable for Utah ratepayers absent rate consideration for the $7.5 million offset to the capitalized cost of the GE LM 6000 units for the lease expense waiver. Therefore, when the Company wanted the Commission to approve their application to build the Gadsby units, they relied in part on the argument that the decision to construct the GE LM 6000 gas turbines would benefit ***both*** the Company and the ratepayers.
>
> The estimated construction cost of the Gadsby units was reduced by $7.5 million for the lease obligation payment waiver when comparisons were made with other competitive alternatives. However, in response to the Division's data request, PacifiCorp indicated that the $7.5 million in cost savings was not treated as a

> reduction in the capital cost of Gadsby in their rate application, they were treated as a $7.5 million reduction in the 2002 O&M expenses. The Utah ratepayers did not benefit from the GE lease payment waiver. PacifiCorp's rates at that time were determined in Docket No. 01-035-01. The expenses associated with the GE lease were outside of the test period and no adjustment was made to include them for rate-making. While the Company may argue that absent the waiver, PacifiCorp would have had $7.5 million more in net power costs in that case test period, other parties could have persuasively argued that such costs were one-time non-recurring costs which should be excluded from rate-making.
>
> Therefore, contrary to the Company's assertion that the lease payment waiver benefited both the Company and the Utah ratepayers, it appears that only PacifiCorp stockholders benefited from the arrangement based on the Company's filing.
>
> In my opinion it would be equitable to reduce the rate base amount approved for the Gadsby units by the Utah allocated portion of the current value of the $7.5 million cost reduction, consistent with the way the Company recognized the amount in comparing alternatives in making the decision to purchase the GE LM 6000 units. In this way the rate reduction will continue as long as the costs associated with Gadsby are recovered in rates from Utah ratepayers, and consequently Utah ratepayers will benefit from the lease waiver consistent with the Company's arguments when the Commission approved the certificate to build the units.

<u>Re PacifiCorp</u>, UPSC Docket No. 04-035-42, Direct Testimony of Bruce Scott Moio at 2-4 (Dec. 3, 2004) (internal citations omitted). Mr. Moio's arguments are reasonable and provide another basis for the Commission to adopt the proposed disallowance.

<u>GP Camas Contract</u>

Q. MR. WRIGLEY NOTES THAT YOUR GP CAMAS ADJUSTMENT DIFFERS SLIGHTLY FROM THAT PROPOSED BY STAFF AND THE COMPANY. PLEASE COMMENT.

A. I accept the figures of Staff witness Breen and PacifiCorp witness Wrigley on this adjustment.

<u>RVM Issues</u>

Q. MS. OMOHUNDRO GENERALLY DISPUTES YOUR CONTENTION THAT AN ANNUAL RVM IS NOT NECESSARY. PLEASE COMMENT.

A. Ms. Omohundro never spells out any specific problems that would result if there was not an annual RVM. Her testimony is rather vague and uninformative on this issue.

Q. MS. OMOHUNDRO TESTIFIES THAT PACIFICORP INTENDS TO MINIMIZE THE WORKLOAD OF PARTIES. SHE CONTENDS THE PROPOSED RVM IS "LARGELY MECHANICAL" AND PATTERNED AFTER PGE'S RVM MODEL. PLEASE COMMENT.

A. PacifiCorp might hope that its RVM will be a "mechanical" exercise. However, experience with PGE has shown that a great number of issues can arise in the RVM setting, including propriety and eligibility of costs, scope of the RVM, modeling techniques, and prudence. There is no reason to expect that PacifiCorp's RVM will be any less complex than PGE's. In fact, given that PacifiCorp is a much larger and more complex system, and that it operates in six states, any annual RVM is likely to be far more complex than PGE's.

Further, PacifiCorp has actually increased the burden on intervenors and the Staff by patterning its RVM too closely after PGE's. Based on discussions held during recent workshops, it appears that the Company is still proposing an annual RVM schedule quite similar to PGE's RVM schedule. This means that parties will have the complexity of dealing with two RVM cases at the same time. While Staff, CUB, and ICNU will have two RVM filings to deal with, PacifiCorp (and PGE) will only be concerned with one. This will certainly make it more difficult for the parties to fully explore all of the issues that impact ratepayers.

Q. MOST OF THE POWER COST ISSUES RELATED TO PACIFICORP'S INITIAL FILING WERE SETTLED. DOES THIS SUGGEST THAT FUTURE RVM CASES WILL BE "LARGLY MECHANICAL," AS SUGGESTED BY MS. OMOHUNDRO?

A. No. In fact, quite the opposite is likely to be true. In future RVM proceedings, power cost issues settled in this case may be litigated again. The Partial Settlement does require the Company to make a deduction from its RVM updates in this proceeding, but future cases will likely see a number of the same types of issues litigated. Had the stipulation addressed specific adjustments, there would likely be fewer disputed issues to resolve in future cases.

Q. MR. WIDMER TESTIFIES THAT IN UM 1081, "MARKET EVEN" MERELY MEANT THAT THERE WAS NO TRANSMISSION ADDER USED IN THE COMPUTATION OF THE TRANSITION ADJUSTMENT. PLEASE COMMENT.

A. The Commission can determine what it meant by "market even" better than Mr. Widmer or I. However, if the Commission's goal was to provide a transition adjustment equal to the market value of the freed up resources, the PacifiCorp calculation does not do so. The Company proposes a transition adjustment based on its Generation and Regulation Initiatives Decision Tools ("GRID") model that, as shown on page 51 of my direct testimony, is lower than the cost of standard market products. What the Company has computed is *not* the market value of the freed-up resources, but rather the value to PacifiCorp of the freed-up resources. Because the Company maintains that it already is unable to sell all of its coal-fired capacity off peak, it concludes that the value of the power in GRID is less than the value of standard products. But, one must ask, why is it then that the cost of standard products always exceeds their value to PacifiCorp? This is a contradiction that must be resolved.

Q. PLEASE EXPLAIN.

A. The Company is suggesting that it is prudent for it to buy 25 MW of a standard product in the market place at a price of $46.38/MWh to serve a 25 MW load. However, if the same 25 MW of load leaves the system for direct access, then the value of the resold power is only $43.68/MWh. The reason is that during the "graveyard shift" the Company cannot resell the product that is no longer needed because there is no market for it, and its coal units would have to be backed down instead. That being the case, one must ask why standard product prices are as high as they are, when there is energy that is virtually "dirt cheap" in the graveyard hours? I can think of three possible explanations.

First, it is possible that the market is not efficient. Ordinarily, one would expect that, if PacifiCorp has idle coal-fired generation in the graveyard shift, then market prices should drop to the cost of coal-fired energy. If it does not, then the market is not efficient. The question then becomes, why should departing loads be assessed the cost of an inefficient market?

Second, it is possible that the GRID model logic or the market cap inputs are seriously flawed. This is possible because PacifiCorp has computed the market caps based on historical data for balancing transaction volumes. However, historically PacifiCorp transacted a substantially greater amount of short-term firm ("STF") transactions than are modeled in GRID. In fact, PacifiCorp excluded 77% of its typical STF transaction volume in GRID because it used only transactions arranged before the filing date. Thus, the size of the total market (both balancing plus STF contracts) has historically been much larger than the Company is assuming in this case. Because of this, the Company is really modeling a much smaller market in GRID than exists in reality.

Finally, the problem may lie with the shaping of standard product prices into hourly prices used by the Company. The Company develops its hourly market prices in GRID based on hourly price patterns derived over many years. To the extent that prices in the earlier years (i.e., the late 1990s) had prices that were much lower than today, with much different shapes, it's possible that the shaping factors used by the Company simply do not reflect current market conditions. Because of this, the prices modeled in the graveyard shift may be higher than current market prices, while prices in other hours may be lower than they should be.

For these reasons, the entire issue of market caps may be a "red herring." Until this can be resolved, I believe it would be wiser for the Commission not to rely on GRID for the transition adjustment modeling.

Q. MR. WIDMER DISPARAGES YOUR TESTIMONY CONCERNING THE ISSUE OF MARKET CAPS ON THE BASIS THAT THIS ISSUE WAS NOT INCLUDED IN THE LIST OF RESERVED ISSUES IN THE PARTIAL STIPULATION. PLEASE COMMENT.

A. First, I am not proposing any market cap adjustment to Net Power Costs or any correction to the market cap adjustment proposed in the Partial Stipulation. Thus, there is no basis for Mr. Widmer's comments. My proposal is to compute the transition adjustment, without the use of GRID, owing in part to problems with the market cap modeling as it impacts the transition adjustment calculation. I do not believe Mr. Widmer, or other parties, dispute ICNU's right to propose an alternative to GRID for computing the transition adjustment.

Q. MR. WIDMER DISPUTES YOUR TRANSMISSION COST ADDER ON THE BASIS THAT TRANSMISSION CONTRACTS ARE FIXED AND NOT AVOIDABLE. DO YOU AGREE?

A. This argument goes to the level of the adjustment, not to its merit. Mr. Widmer has presented no alternative. Further, even if existing transmission contracts are fixed for a number of years, as load grows, undoubtedly additional transmission will be required and be more costly than existing contracts. Thus, my calculation of the average transmission cost per MWh is probably conservative.

Other GRID Issues

Q. MR. WIDMER DISPUTES YOUR DEFERRAL PERIOD OUTAGE ADJUSTMENT. HE CONTENDS THAT THERE IS "NO DOUBLE COUNT" OF DEFERRAL PERIOD OUTAGES BECAUSE IN THIS CASE, THE COMPANY IS ONLY SEEKING TO RECOVER THE NORMALIZED COST OF OUTAGES. DO YOU AGREE?

A. No. Mr. Widmer has included all of the outages that occurred during the deferral period (except Hunter) in his calculation of outage rates. He did so, in his own words, because "*The Company's outage rate modeling is simply a four-year amortization of outage costs*." Re PacifiCorp, WUTC Docket No. UE-032065, Rebuttal Testimony of Mark Widmer at 37 (July 28, 2004). Because the outage rate modeling he proposes is intended to provide a four-year amortization of the very same costs being recovered in the UM 995 deferral, it is a double count.

Q. MR. WIDMER CONTENDS THAT THE HUNTER OUTAGE WAS REVERSED FROM THE OUTAGE RATE CALCULATION BECAUSE IT WAS AN EXTRAORDINARY OUTAGE. IS THIS CONSISTENT WITH HIS PRIOR TESTIMONY?

A. No. In this case, Mr. Widmer testifies that:

> In contrast to the other outages, the length of the Hunter 1 outage was much greater than the normal level included in retail rates, so there was an incremental impact, which resulted in deferral and recovery.

PPL/609, Widmer/3. In UE 147, Mr. Widmer testified that:

> Because the Company is recovering the cost of the catastrophic Hunter unit 1 outage through the treatment adopted in UM 995, the Company has excluded that outage from its 48-month outage calculation.

Re PacifiCorp, OPUC Docket No. UE 147, PPL/500, Widmer/12 (Mar. 19, 2003).

In other words, in UE 147, Mr. Widmer merely acknowledged that the Hunter outage costs were already being recovered, while in the current case he is arguing that it should be reversed because it was much more significant than other outages, resulting in a deferral.

Q. MR. WIDMER TESTIFIES THAT THERE IS NO DOUBLE COUNT OF OTHER OUTAGES IN THE DEFERRAL BALANCE. IS HE CORRECT?

A. Mr. Widmer testifies as follows:

> UM 995 excess net power costs were calculated as the difference between actual net power costs and net power costs included in rates. For example, if net power costs in rates were $500 million and actual net power costs were $700 million, the excess net power cost deferral would have been $200 million. In other words, the Company was collecting the normalized level of outages and market prices as part of net power costs in base rates *and collected the recoverable portion of excess outages and market prices as part of excess net power costs through a separate surcharge*. In this case, the Company is only requesting recovery of normalized costs, so there is no double count with costs related to the UM 995 deferral period.

PPL/609, Widmer/3 (emphasis added).

This passage is purposefully misleading. *All* outages result in increases in power costs. Thus, the $700 million actual power costs in his example is a product of various factors, including *all* of the actual outages. Had the Company had fewer outages, the $700 million figure would be lower. If the Company had no outages, the actual power costs might be only $600 million in this example. In that case, the deferral would be $100 million, not $200 million. Consequently, the extra $100 million is completely attributable to outages, and that cost is what is being recovered via the deferral. In this case, there is absolutely no difference between the Hunter outage and other outages, aside from its magnitude. Every single outage that occurred increased actual power costs, and thereby resulted in a larger deferral balance. Consequently, customers are paying for the costs of all actual outages already in the surcharge. There is simply no basis for an additional "*four-year amortization of outage costs*" as part of the calculation of outage rates.

Q. MR. WIDMER CONTENDS THAT IF OTHER OUTAGES WERE REMOVED IN THE SAME MANNER AS THE HUNTER OUTAGE WAS REMOVED, POWER COSTS WOULD INCREASE SUBSTANTIALLY. DO YOU AGREE?

A. No. Mr. Widmer's testimony on this point is completely misleading to the Commission. The analysis he performs does not do what he says it does. He does not treat other outages the same way as Hunter; he treats them in a much different way. In fact, he does not even treat the Hunter outage in the same way in the two calculations. Therefore, his analysis and his claims are simply false.

Q. PLEASE EXPLAIN.

A. In Mr. Widmer's original filing (and his updates), he reversed the five-month Hunter outage by removing it from the 48-month outage rate calculation. He did so by effectively calculating the outage rates for the period of time when Hunter was not on outage (or the remaining 43 months). Thus, Mr. Widmer excluded from the outage rate calculation only the period of time that the major outage occurred. One could argue about whether this approach also overstates costs, but that was his approach and I used it for all outages in my analysis.

Q. HOW DOES THIS DIFFER FROM HIS NEW ANALYSIS, WHERE HE CLAIMS TO HAVE REMOVED OUTAGES DURING THE DEFFERAL PERIOD?

A. In his new analysis, he now removes the entire ten-month period from the outage rate calculation. This is completely arbitrary, particularly in light of the fact that he has previously argued in favor of a 48-month period. In his new analysis, he now reverses the Hunter outage by removing Hunter for ten months from his outage calculation, rather than the five months he removed previously. His claim that he is treating all outages in the same manner as the Hunter outage is false. He does not even treat the Hunter outage the same as he did in his original GRID studies, because now he computes the Hunter outage rate based on a 38-month period, while earlier he computed it based on a 43-month period. He is doing nothing more than playing a "numbers game" to confuse and mislead the Commission.

Q. COMPARE THIS TO YOUR OUTAGE RATE CALCULATION.

A. In my calculation I did treat all of the outages exactly like the Hunter outage. For example, if a unit had an outage that lasted one month during the deferral period, then I computed the outage rate for that unit based on excluding that month alone, just as I computed the outage rate for Hunter by excluding the five-month period from the calculation. Because the other outages that occurred in the period were no different from the Hunter outage, there is no reason they should be treated any differently in the calculation of outage rates for GRID. In Mr. Widmer's calculation, it would make no difference to the final outage rates if a unit was out of service for the entire deferral period or not at all. Now, should the Commission believe that if a unit were on outage for the entire deferral period, it would have had no impact on the level of the deferred costs? Obviously not! Because Mr. Widmer has presented a false analysis to the Commission, his testimony on this issue should be rejected.

Q. MR. WIDMER DEFENDS HIS RAMPING AND STATION SERVICE ADJUSTMENTS BASED ON SEVERAL CRITICISMS OF YOUR GRID RUN USING HISTORICAL LOADS. PLEASE COMMENT.

A. Mr. Widmer contends that my run using historical loads and hydro levels was incomplete because I did not adjust for a variety of other items that are changed in the current GRID model. To address this issue, there are two approaches that might be used. First, the Company could do a historical "backcast." In this analysis, an attempt is made to recreate historical results, using actual data in the model. If such a study showed that GRID produced too much coal-fired generation compared to what actually happened, he might have a point. However, he has not provided such a study in this case.

Q. HAS PACIFICORP EVER PERFORMED A BACKCAST USING GRID?

A. Yes. In UE 147, the Company provided me an analysis of a historical backcast comparing GRID to actual results for the period October 2001 to September 2002. I have attached an excerpt of this study as Exhibit ICNU/113. In the analysis, the Company contended that GRID predicted power costs within 0.1% of actual. Further, the Company's analysis showed that thermal generation was 1% less than actual, and that GRID predicted coal fired generation 0.7% less than actual. This analysis does not support the conclusion that GRID is producing too much coal-fired generation. Indeed, it supports the opposite conclusion, that if anything, the model was under-predicting thermal generation long before the station service and ramping adjustments were made. This undermines Mr. Widmer's entire basis for the ramping and station service adjustments

Q. ASIDE FROM THE BACKCAST, ARE MR. WIDMER'S CRITICISMS OF YOUR GRID MODEL RUN REASONABLE?

A. No. Mr. Widmer has concluded that because GRID shows more coal-fired generation than historically occurred, there must be something wrong with the model, requiring ad-hoc manipulation of the inputs. However, an equally valid assumption would be that the system has changed, resulting in an increase in coal-fired generation. Given the substantial increase in loads predicted by the Company, the simplest explanation is that the increased loads are resulting in increased generation. Mr. Widmer has done nothing to determine whether the latter explanation is plausible. That is what my GRID study using historical load data accomplished. My goal was not to perform a historical benchmark, but rather to show the extent to which the increase in loads over historical levels might impact actual coal-fired generation. My analysis showed that a substantial increase in coal-fired generation may occur if a substantial increase in loads occurs. Given that coal-fired generation is much lower in cost than market purchases, one would intuitively expect that as load increases, the Company will first increase its output from coal plants. Mr. Widmer would have the Commission believe that no matter how high loads become, coal-fired generation will remain constant.

Q. DO MARKET CAPS HAVE A BEARING ON THIS ISSUE?

A. Certainly. Because of the market caps, the Company cannot sell all of its idle coal-fired capacity during the graveyard shift. However, if load increases, the Company will then be able to increase the utilization of the otherwise idle coal-fired capacity. This will result in an increase in coal-fired generation over historical levels. Mr. Widmer has completely ignored this fact in his testimony.

Q. COMMENT ON MR. WIDMER'S CONTENTION THAT THE UE 139 DECISION REJECTING A SIMILAR ADJUSTMENT BY PGE IS NOT APPLICABLE TO PACIFICORP.

A. Mr. Widmer is wrong. In UE 139, the Commission rejected an ad-hoc data manipulation to address a speculative "problem." Instead, the Commission continued to rely on industry standard modeling methods. Mr. Widmer has not even demonstrated that the "surplus" of coal-fired generation really exists in GRID. Instead, he justifies his entire analysis on a flawed comparison of historical coal generation to current GRID studies. He has not shown that a historical backcast of GRID over-predicted coal-fired generation in the past, nor does he show that the current system configuration and loads would not result in increased coal-fired generation. The UE 139 precedent is on point, because in that case, the Commission correctly rejected result-oriented data manipulation to solve a problem that was never proven to exist.

Q. MR. WIDMER DISPUTES YOUR RECOMMENDATION TO REVERSE HIS DEFERRED MAINTENANCE ADJUSTMENT ON THE BASIS THAT GRID OVER-PREDICTS OFF-PEAK GENERATION. DO YOU AGREE?

A. No. Despite anything Mr. Widmer claims to show concerning when these outages occur, it does not change the fact these outages are *deferrable*. Therefore, they do not need to be scheduled during hours when market prices are at their peak. His adjustment would ignore this fact, and schedule deferrable outages at any time, even the highest priced hours.

Q. MR. WIDMER CLAIMS, ON THE BASIS OF PPL/610, THAT ONLY 49% OF GENERATION LOST DUE TO MAINTENANCE OUTAGES OCCURS DURING LIGHT LOAD HOURS ("LLH"). PLEASE COMMENT.

A. Mr. Widmer's calculation is quite questionable because the amount of lost generation he has computed for LLH and Heavy Load Hours ("HLH") substantially differs from the amount of total lost generation that occurred during the four-year period. Mr. Widmer did not supply complete workpapers, so it is not possible to discern the cause of this discrepancy. More significantly, Mr. Widmer has confused the issue. Prior to the deferred maintenance adjustment, maintenance outages in GRID occurred during the 56-hour weekend period. However, his analysis counts 16 HLH hours that occur on Saturdays. Therefore, PPL/610 does not really provide an accurate indication of the best method to apply in GRID because it includes weekend hours.

Q. MR. WIDMER CONTENDS THAT THE FIGURE REFERENCED ON PAGE 47, LINE 7 (68.5%) OF YOUR DIRECT TESTIMONY IS WRONG. PLEASE COMMENT.

A. I incorrectly stated in my direct testimony that 68.5% of the energy lost due to maintenance outages occurs during LLH. I should have pointed out that I counted the entire weekend along with the LLH hours during weekdays. This is appropriate, however, because we are trying to decide whether to include the maintenance outage on the weekend or not. My analysis shows that 68.5% of all energy lost due to maintenance outages occurs during LLH during the week or on the weekend. By modeling maintenance outages as part of the weekend outage rate, 71% of the energy would be lost in LLH, and 29% would be lost in HLH hours, which is quite close to the actual data. Clearly, it makes more sense to model these outages as part of the weekend outage rate, rather than to assume they occur during all hours, including peak price periods.

Q. MR. WIDMER CONTENDS THAT A SEASONAL MODELING OF MAINTENANCE OUTAGES, AS SUGGESTED IN YOUR TESTIMONY, WOULD RESULT IN HIGHER POWER COSTS. PLEASE COMMENT.

A. Mr. Widmer is distorting my testimony. I never proposed a seasonal modeling of these outages. I merely pointed out that far less energy is lost during peak months than off-peak months, because these outages are deferrable. In the end, Mr. Widmer wishes to ignore the fact that deferrable outages can be scheduled at times (whether LLH or HLH, weekend or weekdays) when market prices are lowest.

Q. MR. WIDMER DEFENDS HIS PROPOSAL TO CHANGE FROM THE COMMISSION'S ACCEPTED PROCEDURE THAT BASES SCHEDULED MAINTENANCE ON THE 48-MONTH AVERAGE. PLEASE COMMENT.

A. Mr. Widmer is advocating that the Commission abandon established practice to gain a small advantage for the Company. His argument that PacifiCorp should be allowed to use this approach because PGE does so is unsound. First, PGE has a Commission-approved RVM resulting from a stipulation among the parties. There is no such agreement among the parties in this case.

In addition, PGE has only one large coal plant, which is critical in determining its power costs. In a given year, whether or not major overhauls are performed can have a substantial impact on power costs. By using the actual schedule, PGE may be better able to predict power costs for the next year. However, should PGE change its maintenance schedule after the RVM filing, that could impact power costs substantially. Because maintenance schedules can change, the use of a 48-month average maintenance schedule for PGE would also be reasonable so long as a consistent approach is followed.

In contrast, PacifiCorp has a large number of coal-fired generators, and it is likely that the major overhaul cycles of various units will balance out over time. Further, past experience has shown (as in the case of the Hunter outage, for example) that PacifiCorp can and does change maintenance schedules. Thus, the year-ahead maintenance forecast is unlikely to be followed in actual practice. Given the history of using the 48-month average for PacifiCorp, and in light of all these factors, I continue to recommend use of the 48-month average instead of the currently forecast schedule.

Q. MR. WIDMER DISPUTES YOUR RECOMMENDATION THAT THE 48-MONTH HISTORICAL DATA PERIOD BE CHANGED. HE CONTENDS THAT ICNU WAS GIVEN THE CHOICE OF FILING ITS TESTIMONY CONCERNING THE MARCH 15, 2005 UPDATE WITH THIS SURREBUTTAL TESTIMONY. PLEASE COMMENT.

A. I am not disputing Mr. Widmer's statements. However, Mr. Widmer did not explain why ICNU turned down this "offer." His proposal was for ICNU to file its comments regarding the updates to GRID with ICNU's surrebuttal testimony. However, the Company would then have had the opportunity to respond to our testimony in its later "sur-surrebuttal" testimony. As this would have denied ICNU the opportunity to put in any response to the Company's defense of his proposed adjustments (as I am now presenting here), we filed our initial comments in ICNU's direct testimony. We believe the record is better served by this approach, even if it did provide ICNU with less time to prepare its case.

In any case, this episode clearly illustrates ICNU's concerns about the proposed RVM process. While the stakes are nearly as high as a full-blown rate case, the "schedule" is very short, extremely fluid, and subject to the whims and abuses of the Company. This provides yet one more reason to reject the annual RVM proposed by the Company.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.