Witness OCS 4D

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Service Rate in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations	)))))))	**Docket No. 10-035-124** **Direct Testimony of Randall J. Falkenberg On Behalf of the Utah Office of Consumer Services**

Redacted

May 26, 2011

DIRECT TESTIMONY OF RANDALL J. FALKENBERG

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8343 Roswell Road, Atlanta, Georgia 30350.

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

A. I am a utility regulatory consultant and President of RFI Consulting, Inc. ("RFI"). I am appearing on behalf of the Office of Consumer Services ("the OCS".)

Q. WHAT CONSULTING SERVICES ARE PROVIDED BY RFI?

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

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS.

A. My qualifications and appearances are provided in Exhibit OCS 4.1.

I. <u>INTRODUCTION AND SUMMARY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses PacifiCorp's Generation and Regulation Initiatives Decision ("GRID") model study of Net Power Costs ("NPC") for the projected test period ending June 30, 2012.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have identified and quantified certain adjustments to the Company's Test Year NPC GRID study. These adjustments are shown on Table 1 and are summarized below. In cases where no adjustment is identified, the comments presented are informational or for comparative purposes only. Confidential Material Removed.

Net Power Cost (GRID)

PacifiCorp's requested NPC of $1,521 million (total Company) in NPC is overstated by $79 million. OCS recommends NPC of $1,442 million, resulting in a reduction to the Utah allocated revenue requirement of $34.08 million. Use of the 12-month test year, ending June 30, 2012, necessitates a number of the adjustments below. Table 1 provides the value of all recommended adjustments. Exhibit OCS 4.2 provides additional detail concerning each adjustment.

Table 1
Summary of Recommended Adjustments - $

	Total Company		Utah Jurisdiction
		SE	42.59%
		SG	43.28%
PacifiCorp Request NPC	1,521,262,900		649,100,000
A. Wind Integration Adjustments			
1 Correct Wind Study Modeling Errors and Biases	(13,891,348)		(5,964,320)
2 Correct Must Run	(6,358,902)		(2,730,226)
B. GRID Start Up Costs			
3 Start Up Cost Adjustments	(1,067,014)		(458,128)
C. Long Term Contracts			
4 Call Option Sales Contract Shaping	(824,252)		(353,897)
5 Trading and Arbitrage Margins	(2,996,570)		(1,286,592)
6 Minor Contract Adjustments	(572,078)		(245,625)
D. Hydro Logic and Inputs			
7 Bear River Capacity and Energy	(2,911,376)		(1,250,014)
8 Lewis River Hydro Modeling	(2,683,305)		(1,152,090)
9 Hydro Outage Rate Adjustments	(2,305,545)		(989,897)
E. Transmission Issues			
10 Transmission Test Year Cost/Benefit Mismatch	(20,064,085)		(8,614,615)
11 NF Transmission Modeling	(2,149,280)		(922,804)
12 Transmission Test Year Adjustments	(2,727,065)		(1,170,879)
13 Line Loss Adjustment	(1,896,543)		(814,290)
14	(601,218)		(258,136)
F. Power Cost Modeling Issues			
15 Chehalis Reserve Capacity	(2,184,929)		(938,110)
16 Station Service Corrections	(304,109)		(130,571)
17 Cholla Reserve Capacity	(891,134)		(382,613)
18 GRID Major Market Caps	(3,705,622)		(1,591,027)
19 JB Fuel Price Error	(2,165,973)		(929,971)
20 Capacity Upgrade	(517,523)		(222,201)
G. Planned and Forced Outage Modeling Issues			
21 Outage Rate Adjustments	(7,116,076)		(3,055,323)
22 Heat Rate Modeling	(1,446,737)		(621,164)
I. Balancing/Final Screens			
23 Balancing/Final Screening Adjustments	-		-
Subtotal NPC Adjustments -	(79,380,684)		(34,082,494)
Allowed - Final GRID Result*	1,441,882,216		615,017,506

A. Wind Integration Study Impacts Modeled in GRID

The Company has included $53 million in costs in the test year based on the results of its 2010 Wind Integration Study. The study suffers from numerous design flaws. While the Company implies the study design was the result of a "collaborative process," it did not incorporate the advice of the various participating experts, resulting in substantial bias in the final results.

The study also contains numerous implementation errors including use of unreliable data, incorrect regression models, math errors, and double counting of several wind farms.[1] The most serious errors resulted from the erroneous regression models used to estimate integration requirements for projects lacking a complete record of actual data. Overall the study overstates reserve requirements by 100-160 MW.

Adjustment 1. Corrects the Company Wind Study by removing double counting and relying on the 2009 - 2010 actual wind generation data along with a more reliable method to develop data for projects where actual data is not available.

Adjustment 2. This adjustment reverses the erroneous assumption that the Gadsby CTs and Currant Creek "must run" around the clock to provide reserves for wind integration. This assumption is unsupported and contrary to actual operations. Adjustment 2 also provides an estimate of the screening impact.

B. GRID Commitment Logic and Start-Up Costs

The Company has now implemented a daily screening methodology to correct the GRID commitment logic error. However, the Company failed to apply it to the assumed "must run" gas units (Currant Creek and the Gadsby CTs) due to their must run modeling.

Adjustment 3. Since the Company includes start-up fuel costs, this adjustment matches those costs with the benefit of the energy produced during the start sequence and also reflects the impact of forced outages on start-up costs.

C. Long Term Contract Modeling

Adjustment 4. The Company incorrectly models two call option sales contracts[2] by assuming the counterparties will take power in the highest cost hours possible. I have modeled more realistic shapes for these contracts. This adjustment is comparable to the SMUD shaping adjustment now adopted by this Commission and also by regulators in Idaho[3] and Washington.[4]

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1 Rolling Hills, Rock River, Leaning Juniper and Goodnoe

2 Black Hills and Utah Municipal Power Authority ("UMPA") II

3 The SMUD and BHP adjustments were adopted by regulators in Idaho in RMP Docket No. PAC-E-10-07

4 The SMUD adjustment was adopted by regulators in Washington in Pacific Power Docket No. UE-100749.

<u>Adjustment 5.</u> GRID does not model any trading or arbitrage profits for short-term firm transactions. I recommend imputation of additional profits, based on historical results for the most recent four years. This adjustment is necessary because the Company is now using a far forward projected test year. This type of adjustment has now been adopted by regulators in Oregon and Washington. [5]

<u>Adjustment 6.</u> This adjustment corrects an error in the Roseburg contract, uses actual data to estimate the energy purchased from the Evergreen contract rather than contractual targets and provides a daily rather than monthly screen for the APS Supplemental contract.

<u>D. Hydro Modeling</u>

<u>Adjustment 7:</u> The Company has understated the capacity and energy available from the Bear River hydro resources. A recent PacifiCorp press release indicates flooding may occur on the Bear River, signaling an end to recent drought conditions. Further the Company has understated capacity available from the plant, which can be used to provide reserves. This adjustment implements normal hydro levels and a reserve capability based on actual operational results.

<u>Adjustment 8.</u> The Company includes two modeling adjustments[6] **in GRID to address assumed shortcomings in the Vista model used to develop GRID hydro inputs. However, the Company's adjustments are one-sided. The Company failed to address a more important problem: Vista does not optimize hydro reserve allocations. This results in numerous periods of reserve shortages in the Western Control Area. I recommend that these two hydro adjustments be eliminated to provide a more balanced application of the Vista model inputs to GRID.**

Further, the Company is developing a new model to address the GRID logic error. It should be required to implement logic to address the hydro reserve optimization in the new model as well. Optimizing hydro reserve allocations is very important for proper determination of wind integration costs in the GRID model.

<u>Adjustment 9.</u> The Company overstates the costs resulting from forced outages at hydro plants. First, the Company uses a different historical period to model hydro outages than was used for thermal outages. Second, the Company assumes these random events occur predominately at high cost periods. Finally, the Company ignores the fact that for storage hydro the energy lost during outages can be rescheduled for later use. The Company agreed to abandon hydro outage rate modeling in recent Oregon cases.[7]

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[5] The Oregon Commission adopted this adjustment in UE 191 in 2007, while the Washington Commission adopted a similar adjustment in the recent order in Docket No. UE-100749.

[6] Lewis River Motoring and Efficiency Loss

[7] OPCU Docket Nos. UM 1355 and UE 207.

<u>E. Transmission Cost Issues</u>

<u>Adjustment 10.</u> The Cal ISO charges, the DC Intertie [redacted] Cal ISO is used for SP 15 trades, but SP 15 is not even modeled in the test year. The DC Intertie is used for Nevada Oregon Border ("NOB") trades, but NOB is not modeled in the test year. [redacted] Disallowances related to two of these contracts have been made by regulators in Idaho[8] and Washington.[9] This adjustment is required to provide a balanced forward test year with costs matching benefits.

<u>Adjustment 11.</u> The Company has improperly changed the modeling of Non-Firm transmission from the Commission-approved method which uses a four year average for price and volumes. This adjustment restores the Commission-approved method.

<u>Adjustment 12.</u> This adjustment removes wheeling rate increases that are not known or measurable and normalizes transmission wheeling expense by removing various penalties paid by the Company for unauthorized use and "failure to comply". This is consistent with the Commission decisions in Docket 09-035-23.

<u>Adjustment 13.</u> This adjustment implements OCS witness Ms. Donna Ramas' proposed line loss adjustment.

<u>Adjustment 14.</u> The Company includes costs related to [redacted], but does not include any link in its transmission topology. This adjustment includes the capacity associated with this cost.[10]

<u>F. Power Cost Modeling Adjustments</u>

<u>Adjustment 15.</u> The Company has failed to install Automatic Generation Control ("AGC") to allow the Chehalis plant to provide spinning reserves. Adding this capability is far less costly than other alternatives and [redacted] This adjustment imputes reserve capability to Chehalis.

<u>Adjustment 16.</u> This adjustment corrects errors in the calculation of station service energy.

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8 Cal ISO charges were disallowed by regulators in Idaho in PacifiCorp Docket No. PAC-E-10-07

9 DC Interties costs were disallowed by regulators in Washington in PacifiCorp Docket No. UE-100749. The Company has not sought recovery of Cal ISO charges in Washington in recent cases.

10 Alternatively, the cost could be removed, producing approximately the same adjustment.

<u>Adjustment 17.</u> Reflects the transmission limitation impacting Cholla operation by reducing the reserve capacity rather than nameplate capacity, which is a more realistic and economical approach.

<u>Adjustment 18.</u> The Company has improperly expanded the Commission approved market cap modeling to include all hours rather than just the five hour nightly graveyard shift. This adjustment limits the proposed market caps to the Commission approved five hour period.

<u>Adjustment 19</u>. This corrects a mistake in the Bridger coal prices used in GRID.

<u>Adjustment 20.</u> Corrects an understatement of capacity for Craig and Hunter.

<u>G. Planned and Forced Outage Rate Modeling</u>

<u>Adjustments 21.</u> This adjustment reduces outage rates included in GRID, by removing imprudent and unrepresentative outage events, and by removing reserve shutdown hours from the EFOR formula.

<u>Adjustment 22.</u> GRID biases heat rates due to its modeling of forced outage rates as capacity derations. When GRID models a unit at its derated maximum capacity, the heat rate normally exceeds the full load average heat rate. This adjustment corrects this problem. I also address some of the Commission's concerns regarding this adjustment. This adjustment has now been adopted by regulators in Oregon[11] and Washington.[12]

<u>Adjustment 23.</u> I recommend the Company be required to make a final GRID compliance run with all Commission approved adjustments and updated screens. Doing so will change the cumulative value of the approved adjustments. Adjustment 23 is a placeholder for the balancing impact of all Commission approved adjustments.

II: <u>NET POWER COST (GRID)</u>

Q. PLEASE DEFINE NPC AND EXPLAIN HOW THE COMPANY DETERMINES TEST YEAR NPC LEVELS.

A. NPC is computed as the sum of fuel, transmission wheeling and purchase power expense less revenue from sales for resale. NPC encompasses FERC expense accounts 501 (fuel),

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[11] OPUC Docket No. UM 1355 required use of this adjustment for future cases.

[12] WUTC Docket No. UE-100749 approved this adjustment.

503 (steam), 547 (other fuel), 555 (purchased power) and 565 (wheeling expense). Account 447 (Sales for resale) is a revenue account that is credited against NPC.

The Company uses the GRID model to determine NPC. GRID is intended to simulate the least cost operation of the Company's production system, as it is used to meet retail and wholesale load requirements. GRID simulates the operation of the generation system, known purchase and sales contracts, and the transmission system used to move power from the source to the various load centers and delivery points. GRID has been used in all of the Company's rate cases and power cost cases since around 2003.

Q. IN PRIOR CASES THERE HAVE BEEN MANY NPC ISSUES ADDRESSED BY THE PARTIES. HAS PROGRESS BEEN MADE IN RESOLVING SOME OF THE NPC ISSUES?

A. Yes in some areas. For example, the Company has now implemented a more realistic daily screening method to address the GRID commitment logic error in a reasonable manner. The Company has also proposed a reasonable planned outage schedule, and has properly implemented the Commission ordered SMUD adjustment. However, NPC remains a dynamic area and new issues have arisen, notably those related to wind integration, the proper means to address the projected test year, and the Company's expansion of certain adjustments beyond the boundaries approved by the Commission in prior cases. Consequently, the total number of NPC issues remains about the same as in prior cases.

A. Wind Integration Study Modeling in GRID

Adjustments 1-2: Wind Integration Study Impacts

Q. HOW DOES THE COMPANY MODEL WIND INTEGRATION COSTS IN THE TEST YEAR?

A. The Company models several different cost components related to wind integration. These include inter-hour costs, intra-hour costs, BPA wind integration charges and contingency reserves associated with the wind resources. The intra-hour costs are comprised of costs associated with additional reserve requirements (called "regulating margin") and costs related to "round the clock" operation of certain gas plants. Increasing reserve capacity increases costs because reserves cannot be used to serve load or sell into the market. Table 2 below summarizes the Company's test year wind integration costs.

Table 2
Test Year Wind Integration Costs
Total Company $M

Inter-Hour Costs	4.0
Regulating Margin for Wind	21.9
Must Run Gas Plants	9.7
Contingency Reserves	1.9
BPA Wind Integration Charge:	3.1
Total Wind Integration Cost	40.6
Utah Share	17.4
Added Reg. Margin for Load	12.7
Total Cost	53.3
Utah Share	22.9

Q. HAVE YOU IDENTIFIED PROBLEMS WITH THE MANNER IN WHICH THE COMPANY MODELED WIND INTEGRATION COSTS?

A. Yes. While the Company requests some $41 million in normalized wind integration costs, it has not quantified actual wind integration costs and contends it is not feasible to do so.[13] Further the Company has increased regulating margins requirements needed to serve load by an additional $13 million based on this study, but as in the case of wind integration costs, contends it is not possible to determine actual regulating margins that could be used to compare to these projected costs.[14] Finally, the Company GRID study shows West Control Area ("PACW") reserve shortages in excess of 156 thousand MWH, largely due to its failure to meet all of the additional wind integration reserve requirements. The cost of these reserve shortages is difficult to assess but would likely exceed $1 million if included in the test year. However, these costs are largely eliminated by the various adjustments I propose. This issue will be discussed later in this testimony in relation to hydro reserve allocations.

Q. HAVE YOU PREPARED A TECHNICAL APPENDIX THAT SETS FORTH IN DETAIL THE PROBLEMS WITH THE COMPANY'S STUDY AS WELL AS YOUR ANALYSIS OF THE APPROPRIATE LEVEL OF WIND INTEGRATION AND RESERVE COSTS TO INCLUDE IN NPC?

A. Yes. The issues with the Company's 2010 study are both complex and, at times, highly technical. Therefore, for simplicity's sake, I have put my full critique of the Company's study and my alternative study into a technical appendix identified as Exhibit OCS 4.3.

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13 The Company has stated this on many occasions, most recently in Wyoming PSC Docket 20000-389-EP-11, WIEC 1.61, See also WIEC 1.37.

14 The Company has stated this on many occasions, most recently in, Wyoming PSC Docket 20000-384-EP-10, WIEC 8.14

Exhibits OCS 4.4, 4.5, 4.6, 4.7, 4.8 and 4.9[15] also address the problems in the Wind Integration Study.

Q. IS THE COMPANY'S ESTIMATED LEVEL OF WIND INTEGRATION COSTS REASONABLE?

A. No. The Company has not proven that its test year wind integration costs relate in any way to its actual wind integration costs. Rather, the Company has included approximately $41 million in wind integration costs in the test year based on the results of its 2010 Wind Integration Study. However, that study should be rejected in its entirety for three reasons. First, the study suffers from numerous design flaws. Second, while the Company implies the study design was the result of a "collaborative process," it didn't incorporate the advice of the various participating experts and other parties, resulting in substantial bias in the final results. This is discussed in depth in Exhibit OCS 4.3. Third, the study contains numerous implementation errors including use of unreliable data, incorrect regression models, math errors, and double counting of several wind farms. The most serious errors resulted from the erroneous regression models used to estimate integration requirements for projects lacking a complete record of actual data. These errors overstate reserve requirements for wind integration by 100-160 MW. The Company compounds this problem by assuming the overstated reserve requirements necessitate round the clock operation of Currant Creek and the Gadsby CTs. This assumption is not supported by actual operations. Adjustment 1 corrects the modeling of reserves in GRID by reducing reserve requirements and removing the double counting of contingency reserves. Adjustment 2 corrects the must run modeling of the Gadsby CTs

[15] Exhibits OCS 4.4, 4.5 and 4.7 are confidential.

and Currant Creek. These adjustments also, by themselves, eliminate more than half of the GRID reserve shortages.

B. GRID Commitment Logic Error and Start-Up Costs

Q. PLEASE PROVIDE SOME BACKGROUND CONCERNING THIS ISSUE.

A. Absent user-supplied workarounds, the internal logic of GRID frequently fails to utilize the least cost schedule for gas-fired resources, meaning that, there are many hours when gas-fired generators fail to operate economically within the model. This error in turn has a spillover effect on how coal-fired generation is modeled because the uneconomic operation of gas plants forces lower cost coal units to have their output curtailed, raising net power costs in the GRID model.

Q. DID THE COMPANY ATTEMPT TO ADDRESS THIS PROBLEM IN ITS NOVEMBER 2010 FILING?

A. Yes. As I recommended in earlier cases, the Company has now implemented a more realistic daily screening process in order to correct the scheduling error. I reviewed the Company's new screening method and compared the results they derived with those from my own screening models. I am satisfied with the Company's methodology insofar as it has been applied.

Q. DID THE COMPANY APPLY ITS METHODOLOGY TO ALL OF THE RESOURCES IMPACTED BY THE GRID LOGIC ERROR?

A. No. Due to the "must run" modeling of Currant Creek and the Gasby CTs, the Company did not apply screens to those gas units. However, as explained in Exhibit OCS 4.3 regarding wind integration costs, I removed the must run designations, which then requires screens for these resources. I approximated the results of a screening adjustment for these units in computing Adjustment 2. Further, the Company did not apply a daily screening adjustment to the APS Supplemental contract (a call option purchase.) I do so in a subsequent adjustment.

<u>Adjustments 3: Start Up Fuel Cost and Energy</u>

Q. DO YOU AGREE WITH INCLUSION OF START-UP GAS COSTS IN GRID?

A. Yes, these are legitimate power costs and are determined by the screening adjustment. However, the Company considers only the <u>cost</u> of fuel required to take the unit from a warm shut-down state to minimum load, but ignores the energy produced during this process. During the period the units are ramping up (about 2 hours), the output of these units is gradually increasing, producing energy to offset other resources. This energy should be reflected in the test year. Further, because the Company derates the capacity available from its gas units to account for forced outages it should also adjust the start up fuel to account for hours lost due to forced outages. For example, if a unit has a 5% outage rate, its start up fuel cost should be reduced by 5% to reflect outages.

Q. DID MR. DUVALL ADDRESS THIS ISSUE IN HIS TESTIMONY?

A. Yes, this issue was unresolved in the last case and the Commission required the Company to address it further.[16] Mr. Duvall argues that there are offsetting factors that should be considered if the value of startup energy is included. Mr. Duvall references a GRID run, which he claims shows an increase in NPC of $0.6 million should accompany the start up energy adjustment.

Q. DO YOU AGREE?

A. I don't agree with Mr. Duvall's contention that properly modeling start up energy would increase rather than decrease NPC. However, start up energy should be modeled

[16] Final Order Docket No. 09-035-23, Page 34.

irrespective of the impact on NPC. I question the accuracy of Mr. Duvall's results for two reasons. First, his GRID study is based on the test year from the Docket 09-035-23 thus is not directly relevant. Further, a review of the calculation of the $0.6 million figure reveals that Mr. Duvall has only included the effect of longer downtimes in GRID, but did not actually model the value of the start-up energy within the model. Instead, he based the analysis on the DPU's rather conservative methodology from Docket 09-035-23 which values the startup energy at the cost of coal generation. He then compared that value to an analysis based on including longer downtimes for gas plants in the GRID model. As a standalone adjustment, I would accept the DPU method because it is conservative enough to determine the value of the startup energy, while recognizing that there are other, offsetting, factors. For the 2009 GRC test year, the DPU methodology produced a start up energy value of $1.7 million.[17] For the current test year, the value is much smaller because the number of starts for the gas plants has diminished substantially.

If start up costs and energy are modeled in GRID, a more balanced approach than what Mr. Duvall provided is needed. One should not only reflect the impact of longer down times (as Mr. Duvall proposes), but also should consider the value of the energy as determined within (not outside of) the model. A more detailed analysis, which takes account of the actual downtimes and value of replacement energy as determined in GRID, supports a much higher value for startup energy ($3.7 million) than the DPU approach. This is because the energy offset (even when reserves and other factors are accounted for) is not just from coal resources, but also comes from gas resources, which have a much higher cost than coal energy. If this approach were applied to Mr. Duvall's GRID results, the net effect would not be an increase to NPC of $0.6 million, but rather a

[17] Excluding Hermiston.

decrease of $1.6 million, which is about the same as the result computed under the DPU method. Because the importance of this issue is now greatly diminished, for purposes of this case, I recommend the Commission simply adopt my Adjustment 3, which uses the value of coal energy to approximate the net result of a more detailed modeling approach that would include both the downtime changes and the start up energy in GRID.

C. Long Term Contract Adjustments

Adjustments 4: Call Option Sales Contracts

Q. WHAT IS A CALL OPTION CONTRACT?

A. These contracts allow the purchaser the right to pre-schedule energy deliveries based on expected market prices and/or the purchasers' requirements. The Company models several "call option sales" contracts including Black Hills Power ("BHP"), the Sacramento Municipal Utility District ("SMUD") and Utah Municipal Power Agency ("UMPA"). In Docket Nos. 07-035-93 and 09-035-23 the Commission required the Company to make a shaping adjustment to the SMUD contract to reflect actual delivery patterns rather than GRID's unconstrained modeling. In the unconstrained modeling, the Company assumes the highest cost delivery pattern possible will be selected by the counterparty. In prior cases it has been shown that actual delivery patterns are much less onerous than the unconstrained GRID modeling result predicts.

Q. IS THE COMPANY'S MODELING OF SMUD IN COMPLIANCE WITH THE COMMISSION'S ORDER IN THE PRIOR CASES?

A. Yes. I have reviewed the Company's workpapers and believe the Company is modeling SMUD in compliance with the Commission's prior orders. However, the Company continues to apply the unconstrained call option modeling to other contracts included in GRID, specifically the Black Hills Power and UMPA II contracts.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission require a similar modeling approach be applied to the BHP and UMPA II contracts. The Company already models the delivery points for BHP on the basis of historical data, and I have developed monthly HLH and LLH delivery patterns for this contract based on actual data for the most recent 12 month period. For UMPA the adjustment simply flattens the delivery pattern during off-peak hours to approximate the actual data.

Q. HAVE REGULATORS IN OTHER STATES MADE ADJUSTMENTS TO PACIFICORP'S CALL OPTION SALES CONTRACT MODELING?

A. Yes. In Idaho Public Utilities Commission Docket No. PAC-E-10-07, regulators adopted the comparable SMUD and BHP adjustments proposed in that proceeding.[18] Also in Washington Docket UE-100749, the WUTC ordered the Company to make the SMUD adjustment.[19]

<u>Adjustment 5: Arbitrage and Trading Profits in GRID</u>

Q. EXPLAIN THE DIFFERENCE BETWEEN BALANCING, ARBITRAGE AND TRADING AS REGARDS SHORT-TERM FIRM TRANSACTIONS.

A. Balancing is the process of matching supply and demand. The Company constantly engages in short-term transactions to effectuate a more optimal balancing of the system.

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18 Idaho PUC, Order 32196, page 34. The UMPA II contract issue was not raised in that case.

19 WUTC Docket No. UE-100749, Order No. 6, paragraph 136, page 52. Note that the BHP and UMPA II contracts were not at issue in Washington due to their exclusion of that contract from rates on other grounds.

The goal of balancing is to match supply and demand and minimize costs, but not necessarily to make profits on transactions.

Arbitrage occurs when the Company takes a position in one trade, and simultaneously reverses it in another trade at a better price. It is sometimes able to do this because its transmission system is quite large and can adjust the dispatch throughout its system. Arbitrage exploits differences in prices in different counterparties, locations or markets. Profit maximization is the goal of arbitrage and when the right opportunities are present, it is not a risky endeavor.

Trading is when the Company takes a position (long or short) at one price, and then reverses that position later at a price that is expected to be better. The goal of trading is to produce profits; however, it involves an element of risk because expected price changes may not occur.

Q. HAS THE COMPANY INLCUDED ANY PROFITS FROM ARBITRAGE AND TRADING IN GRID?

A. No. Such transactions are normally entered into shortly before the time they are made. As a result, the test year does not include these kinds of profits. While the Company contends that GRID will also model arbitrage between these secondary markets, it has admitted for some time that it could not quantify the amount of arbitrage occurring in the model or even tell parties how to perform such a calculation.[20]

Q. SHOULD GRID REFLECT STF ARBITRAGE AND TRADING PROFITS?

A. Yes. The PacifiCorp generation and transmission system (which is paid for with ratepayer funds) allows the Company to engage in arbitrage and generate additional

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20 See, for example, responses to WIEC 5.4, WIEC 12.21 and 12.22 from Wyoming Docket No. 20000-ER-277-07. More recent responses in other proceedings confirm that this situation remains unchanged.

profits or losses to the Company. Over the period 2003 to mid 2010, the Company generated average yearly arbitrage and trading profits in excess of $3 million.[21] I recommend these profits be imputed to GRID. This is Adjustment 5 on Table 1.

Q. DOES THE SELECTION OF THE JUNE 30, 2012 TEST YEAR HAVE A BEARING ON THIS ISSUE?

A. Yes. The arbitrage and trading margins generally do not occur until very close in time to the time when transactions are made. Because the test year used in this case is far forward into the future, there is little opportunity for inclusion of these kinds of transactions in the test year. Consequently, inclusion of this adjustment is necessary to provide a balanced test year in this case.

Q. IN DOCKET NO. 07-035-93 YOU PROPOSED A SIMILAR ADJUSTMENT, BUT WITHDREW IT IN YOUR SURREBUTTAL TESTIMONY. PLEASE EXPLAIN WHY THIS CASE DIFFERS FROM THE PRIOR CASE AS REGARDS THIS ISSUE.

A. In that case, I withdrew the adjustment in order to minimize controversy as there were a great many issues in play at the time. Further, in that proceeding, the adjustment seemed less applicable because the test period being used was not being projected as far into the future. Finally, the Company now has been authorized to use a balancing account for power costs and if trading margins are excluded from the baseline, the net effect is to allow the Company to retain a share of the margins.

Q. HAVE OTHER COMMISSIONS ADOPTED THIS ADJUSTMENT?

A. Yes. In the Oregon case UE 191 the OPUC stated:

[21] See response to WIEC 5.2 from WPSC Docket 20000-ER-277-07 for 2003-2006 and Exhibit PPL/103 from OPUC Docket UE-227 for 48 months ending June 30, 2010 results. In both cases the figures support a value of $3 million.

> Thus, we accept Staff's premise that the GRID model systematically understates the extent of Pacific Power's wholesale market activities. From that premise Staff infers that Pacific Power receives a systematic positive return on its net short-term wholesale transactions that are not included in the GRID runs. Staff attributes that return to Pacific Power's ability to leverage the flexibility of its diversified system.
>
> * * *
>
> The remaining 13 percent of Pacific Power's short-term wholesale transactions are properly attributed to Pacific Power's arbitrage and wholesale trading activities. The Company calculated that the Oregon allocated margins on such activities averaged $0.8 million annually (from 2003 through 2006). There is no evidence that those results are included in the GRID model results. However, we conclude that such revenues are properly considered in the calculation of NVPC and the model results should be adjusted as necessary to incorporate those revenues.[22]

The Company has filed its Oregon cases using this adjustment ever since 2007. More recently, in Washington Docket UE-100749, the WUTC adopted a similar adjustment, imputing margins for arbitrage profits:

> *Commission Decision.* Staff and ICNU's proposed adjustments raise the essential question of all power cost modeling: how well does the model capture expected expense and revenues of actual utility operations? The Company acknowledges that arbitrage sales occur and argues that the system balancing in the GRID model acts as a proxy for these sales. The question is whether the GRID model represents short-term sales. In this case, we are convinced that it does not.
>
> We should accept proxy results only if no better alternative is available. In this case, we have a better alternative: the four-year average of actual operations. PacifiCorp does not argue that Staff's and ICNU's numbers are not representative of the sales it would anticipate during the term rates will be in effect. Accordingly, we accept ICNU's calculation of arbitrage sales.[23]

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22 OPUC Docket No. UE 191, Order 07-446 pages 10-11.

23 WUTC Docket No. UE-100749, Order No. 6, paragraph 111 and 112, page 44. Note that I would prefer to eliminate the trading profits from the estimated amounts as was accepted in Washington leaving only arbitrage, as they generally average out to zero.

Adjustment 6: Minor Contract Adjustments

Q. WHAT IS THE PURPOSE OF ADJUSTMENT 6?

A. This adjustment corrects some minor problems related to contract modeling. First, the Company has estimated the test year energy for the Evergreen contract based on a four year average of deliveries from July 2006 through June 2010. However, the facility didn't come on line until November 2007, so data prior to the contract start date were assumed to equal the contractual target levels. However, actual deliveries have been lower though it appears contract minimum requirements have been satisfied. To resolve this problem, I used the actual deliveries for Nov. 2007 to Oct. 2010 to compute the annual energy deliveries.[24] This included all of the available data.

Second, the Company used a monthly screen to restrict the APS Supplemental contract deliveries, rather than a daily screen, as it used for thermal plants. Use of a daily screen enables more economical utilization of this resource.

Finally, the adjustment corrects an error in the Roseburg Forrest Products contract energy modeled in GRID. Table 1 combines these adjustments, but OCS 4.2 provides the value of each adjustment individually.

D. Hydro Modeling

Adjustment 7: Bear River Energy and Capacity

Q. HOW DOES THE COMPANY DETERMINE THE ENERGY OUTPUT FOR BEAR RIVER HYDRO RESOURCES?

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[24] The DC Forrest Products contract also uses 2 months of contract data in place of actual. I have no objection to eliminating this data or replacing it with actual results, however, the impact would be inconsequential.

A. For all other hydro projects the Company uses median hydro conditions over a historical period spanning 30 years or more to normalize hydro conditions. For Bear River, the Company computes hydro generation by excluding the "flood control" years from the most recent 30 year period. The Company has done so on the basis that recent drought conditions imply that flood control operation is unlikely, and should be excluded from the historical database. The Company recently reiterated this position in its May 6, 2011 testimony in the current Wyoming General Rate Case:

> **"**Mr. Widmer's adjustment to include flood control releases is unsupported and based on a misunderstanding of the facts. I present evidence to show that the current level of Bear Lake will not result in flood control releases in the rate effective period. Mr. Widmer's contentions are inconsistent with the historic operation of the Bear River system." (WPSC Docket No. 20000-384-ER-10, Rebuttal Testimony of Gregory N. Duvall, page 15.)

However, on May 5, 2010, the PacifiCorp web page presented a press release stating as follows:

> May 05, 2011: SALT LAKE CITY — Managers of the Bear River system in northern Utah and southeastern Idaho have been closely monitoring spring runoff conditions in the Bear River basin. They conclude that the potential for flooding is high all along the Bear River below Bear Lake, including the area between Wardboro and Bern in Bear Lake County, Idaho.
>
> "Based on runoff forecasts, we believe there will be localized flooding of the Bear River into its historic flood plain," said Connely Baldwin, Rocky Mountain Power hydrologist. "There are many variable factors that could influence the extent of flooding, including how rapidly snow melts and the possibility of a local heavy rain storm. However, people with property along or near the river should take all prudent measures to address the risks. These conditions could rival or perhaps exceed those of 1983-84."

This press release appeared on PacifiCorp's home page in early May, 2011.

Q. WHAT IS THE IMPLICATION FOR THE TEST YEAR?

A. It seems clear that the drought conditions justifying the Company's assumption that Bear River should be modeled differently from other resources no longer exists. Second, I think it illustrates that trying to forecast hydro output from recent conditions is problematical, at best. I recommend that the Commission require the Company to model Bear River using its conventional normalization techniques which includes flood control years in the data set used to determine median conditions. The alternative would be to model hydro based on recent conditions for all plants, including Bear River. There is no evidence that such an approach would be feasible, or improve accuracy. As the Bear River example shows, hydro conditions can change quickly and poor hydro years may be followed by very wet years. Further, if one were to attempt to make the most accurate predictions of generation for the upcoming year, it would apparently result in much higher generation as hydro conditions at Bear River appear to be approaching very high levels.

Q. ARE THERE OTHER BEAR RIVER INPUTS THAT REQUIRE REVISION?

A. Yes. Two of the Bear River projects (Oneida and Cutler) have a limited amount of storage capability. In GRID, it is assumed that the storage capacity provides up to 60 MW of reserve carrying capability. However, for Bear River the reserve allocation is limited to the actual capacity less the hourly dispatch. The Company has understated the actual capacity of the resource in GRID and in so doing limited the capacity available for carrying reserves.

Review of actual reserve allocation data shows that these resources frequently carry reserves of 50 MW or more. I recommend an increase to the reserve carrying capability. I used [redacted] based on the average of the monthly reserve allocations from 2007-2010. Actual reserve allocations exceeded this level for hundreds of hours.

Q. DID YOU RAISE THIS ISSUE IN DOCKET 09-035-23?

A. Yes. In that case I also recommended an increase to Bear River reserve allocations. Mr. Duvall argued that my recommendation to increase the reserve capability was unrealistic. However, in 2010 Bear River's actual reserve allocation was [redacted] on average, a substantial increase from the GRID input assumptions. I withdrew the adjustment in that case but indicated OCS would continue to monitor this issue. As events have transpired it is clear that the Company's assumptions related to Bear River are and have been unrealistic.

<u>Adjustment 8: Lewis River - Reserve Optimization</u>

Q. HAS THE COMPANY RECENTLY CHANGED ITS MODELING OF THE HYDRO RESOURCE IN GRID?

A. Yes in earlier cases, the Company used GRID's internal logic to develop the optimal hourly shape for hydro based on input weekly hydro energy. The weekly energy was derived from a model called Vista. The Vista model is used within the Company for various applications related to hydro modeling. Starting with the 2009 GRC, the Company used Vista to develop the optimal hourly schedule bypassing the GRID logic. However, the Company was concerned that Vista "over-optimized" hydro by producing a more efficient hydro simulation than is actually possible. The Company introduced two additional adjustments, (Lewis River Efficiency Loss and Motoring) to address this perceived problem.[25] For example, Mr. Duvall cited the need to carry spinning reserves

[25] Docket No. 09-035-23, Duvall Direct Testimony, pages 13-14.

on the Swift project as necessitating the motoring adjustment. Mr. Duvall contends this was not factored into the Vista model results.

Q. WERE THESE ADJUSTMENTS IMPLEMENTED IN A BALANCED MANNER?

A. No. Mr. Duvall's one-sided adjustments ignore the fact that Vista fails to optimize hydro reserve allocations.[26] Rather, Vista only considers market prices in determining optimal hydro schedules. In actual operations, hydro reserve allocations are made on a day-ahead basis *after* Vista has determined a price optimized dispatch. If reserves are allocated properly, it will minimize costs while meeting constraints and requirements. Mr. Duvall has only provided a solution to Vista's limitations that increases NPC, while ignoring this issue which would reduce NPC.

Q. ARE THERE OTHER PROBLEMS RESULTING FROM THE USE OF VISTA?

A. Yes. When the Vista data is input directly into GRID, in conjunction with the Company's substantially overstated reserve requirements for wind integration (and the Company's failure to have made investments necessary to allow Chehalis to carry reserves which will be discussed later), the result is a reserve shortage in the West control area of more than 156,000 MWH (17.8 MW on average) in the test year. This result is quite unrealistic and indicative of inaccurate modeling assumptions.

Q. IS IT DIFFICULT TO IMPROVE OR OPTIMIZE RESERVE ALLOCATIONS?

A. No. Improving the reserve allocations is simple. A GRID run where the Yale project was modeled without any hourly shaping (using only monthly average output) produced NPC $16 thousand lower than the Company's GRID study. At the same time, it eliminated more than 60% of the PACW reserve shortages. Placing a reasonable value on reducing the reserve shortages would result in a reduction to NPC of more than $923

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[26] See, for example, WIEC 1.13 Wyoming PSC Docket No. 20000-384-ER-10

thousand. Using a flat monthly profile for both Yale and Swift 1 would eliminate 88% of the PACW reserve shortages and reduce NPC by comparable amounts.

To optimize hydro reserve allocations, the process is quite similar to the screening adjustments and relies on a recent GRID enhancement which facilitates the process. To derive optimal reserve allocations I performed two GRID runs. In the first run, I simulated operation for Swift at full capacity every hour. When operating at full capacity, there is no reserve capacity available. Therefore, this run provides the hourly value of the resource for producing energy only. Next, I performed a run with the hourly dispatch set to zero, but retaining the full capacity of the resource for reserves. This run provides the value of the resource for providing reserves, but no energy. The difference between the two runs, unitized by the plant output, provides the value of the resource for providing energy less the value of reserves. This provides an appropriate hourly price for use in optimizing the plant output. I followed the "strike price" methodology described by the Company in discovery[27] in a recent case to develop the optimal weekly dispatch for hydro. This is illustrated in Confidential Exhibit OCS 4.10. The technique simply finds a "strike price" where hydro resources are activated in order to maximize the value of hydro to the system.

Q. DOES THIS APPROACH ADDRESS ANY OTHER CONCERNS?

A. Yes. The GRID commitment logic error which impacts gas units impacts hydro as well. To the extent that Vista only considers market prices, and not market caps or transmission limits, the price optimized schedule it develops does not necessarily produce the least cost utilization of hydro. The solution I propose is essentially an expansion of the screening adjustment to hydro.

[27] ICNU 1.41 OPUC Docket No. UE199.

Q. DID YOU ALSO CONSIDER CONSTRAINTS?

A. Yes. I analyzed limiting the weekly energy and maximum capacity to the amounts determined by Vista. I also analyzed limiting hourly changes in capacity by averaging the results over several periods each day. For Swift Unit 1 alone, this produced a reduction to NPC of approximately $1.5 million on a Total Company basis and reduces reserve shortages by 40%. If the value of reducing reserve shortages is considered, the Swift 1 optimization reduces NPC by more than $2.0 million. I believe if these adjustments were implemented for all hydro resources it would exceed the level of the Lewis River Efficiency Loss and Motoring adjustments substantially.

Q. WHAT IS YOUR RECOMMENDATION?

A. The Company is developing a new model to address the GRID commitment logic error. Rather than optimizing the hydro reserve allocations in this proceeding, I recommend the Company eliminate the Lewis River adjustments in this case, but implement a hydro reserve optimization methodology in the new model. Unless the Company fairly implements all of the necessary adjustments related to curing the deficiencies in the Vista model, it should not include any. Adjustment 8 removes the effect of the Lewis River Efficiency Loss and Motoring adjustments. However, if the Company is allowed to implement these adjustments it should be required to implement my proposed screening adjustment to all hydro units with storage as part of its compliance GRID run.[28]

<u>Adjustment 9: Hydro Outage Modeling</u>

Q. DOES THE COMPANY MODEL HYDRO FORCED OUTAGES IN GRID?

[28] A compliance GRID run would combine all Commission approved adjustments and implement new screens based on those final adjustments.

A. Yes. For run of river units, forced outages are factored into the annual energy production. For storage units, the Company makes assumptions about when outages might occur, based on historical outages and simply removes a certain number of days of hydro generation from the Vista model.[29] The Company effectively models hydro forced outages as if they were outages and known in advance and all the energy is lost for all time.

Q. DO YOU AGREE WITH THE COMPANY'S MODELING?

A. No. For storage hydro the primary effect of forced outages is to reduce the <u>value</u> rather than the amount of hydro energy that may be produced. This occurs because energy may not be available for the most optimal dispatch periods. If energy is not available due to an outage of one turbine, it could be stored for later use, or perhaps used in another turbine at the same plant, particularly, if the outage occurs during minimum or median flow conditions. Outages that occur during periods where the power has a low market value have little or no impact on overall NPC.

Q. IS ANY OF THE HYDRO ENERGY LOST DUE TO SPILLAGE DURING FORCED OUTAGES?

A. That is possible, however, in the response to OCS 20.9 the Company cited only 3 events in four years producing an average energy loss of 10,299 MWH. This is less than 20 percent of the hydro energy the Company assumes will be lost due to forced outages.[30] Further, the Company acknowledged in OCS 20.9 that nearly all of the lost energy due to spillage resulted from a single event, which occurred during a period of heavy rain, and no spillage would have resulted had the event occurred during a different time of the

[29] See OCS 20.7, 20.8 and 20.9

[30] See Attachment OCS 37-1.

year. Under median flow conditions (assumed in the Company's hydro modeling) it seems unlikely that any losses due to spillage would occur.

Q. IS THIS THE ONLY PROBLEM WITH THE COMPANY'S MODELING?

A. No. Another problem in the Company modeling is that the assumed timing of hydro outages in the Vista model occurs at times when the market value of the forgone revenue is higher than average, based on the pattern of outages (as determined on a monthly basis) during the historical period. Because outages are random, there is no reason to expect that hydro outages will occur preferentially during higher value periods. This issue is really the same argument from a few years ago, when the Company was modeling thermal outages based on historical monthly patterns, rather than as random events. For thermal plants, the Company no longer models monthly forced outage rates.

Finally, the Company acknowledged in OCS 8.37 that it selected hydro outages based on an outdated four year period, rather than the 48 months ended June, 2010 used for other GRID inputs. This further overstated NPC.

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

A. Adjustment 9 provides corrections to the Company's test year based on a more reasonable modeling of hydro outage rates. I first updated the outage rates to reflect the 48 months ended June, 2010. Next I assumed the energy lost in the Company's modeling was rescheduled to times when prices were lower. I assumed that the value of rescheduled energy was the average market price during the test year, rather than higher prices assumed during outages.

Q. HAS THIS ISSUE BEEN CONSIDERED IN OTHER PROCEEDINGS?

A. Yes. This issue was explored in various workshops and filings in Oregon Docket No. UM 1355. In that case, the Company agreed that for storage units, forced outages were random,[31] would not necessarily result in a loss of energy,[32] and that there was no industry standard for modeling hydro forced outage rates.[33] The Company stated it was open to working with parties to improve its method,[34] but instead ended up withdrawing its modeling of hydro forced outage rates in its supplemental testimony.[35] The methodology the Company uses in this case is even more onerous than the modeling proposed in Oregon because it assumes all of the energy lost due to forced outages is spilled, while in the prior cases it assumes some of it was rescheduled.[36]

E. Transmission Cost Issues

Adjustment 10: Transmission Test Year Cost/Benefit Mismatch

Q. WHAT IS THE PURPOSE OF CAL ISO WHEELING COSTS?

A. Cal ISO charges are incurred when the Company moves power between Mona and SP 15. However, no such transactions are modeled in the test year. Indeed, the Company does not even model SP 15 as a balancing market in GRID nor does it serve any load in SP 15. Typically, these transactions are part of the Company's hedging strategies and do not normally have a long lead time. Consequently, these types of transactions are not in the forward test year because the Company did not know when the case was filed whether any such transactions would exit.

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31 OPUC Docket No. UM 1355, PPL/200, Smith/3
32 Id at 2
33 Id at 7
34 Id.
35 OPUC Docket No. UM 1355, PPL/405, Duvall/23
36 See OCS 20.9

Q. HAVE CAL ISO WHEELING EXPENSES AND TRANSACTIONS BEEN DECLINING OVER THE PAST SEVERAL YEARS?

A. Yes. It appears that financial transactions such as swaps have eliminated the need for many of the physical trades. Actual Cal ISO fees have decreased by more than 50% in the past few years.

Q. WHAT IS THE PURPOSE OF THE DC INTERTIE CONTRACT?

A. [redacted][37] [redacted][38] [redacted][39] [redacted]

Q. WHAT WAS THE ORIGINAL PURPOSE OF THIS CONTRACT?

A. [redacted][40] [redacted]

Q. EXPLAIN THE PURPOSE OF THE [redacted].[redacted]

[37] Attach 746-700, 700-23.C8. See also WUTC Docket No. UE-1007469, Response to ICNU DR 1.33
[38] See WPSC Docket No. 20000-384-ER-10, WIEC 1.72
[39] WUTC Docket No. UE-100749, Response to ICNU DR 10.3.
[40] Wyoming PSC Docket No. 20000-384-ER-10. WIEC 1.73

A [redacted][41] [redacted]

Q. HAS THE COMPANY ATTEMPTED TO SELL THE RIGHTS OR FIND OTHER USES FOR EITHER OF THESE CONTRACTS?

A. Yes. According to the response to UIEC 14.4, the Company has attempted to sell the rights to the [redacted] contract since July 2009. The Company has, however, redirected a small portion [redacted][42] Based on the response to UIEC 14.7, no such efforts have been made relative to the DC Intertie contract.

Q. WHAT IS YOUR RECOMMENDATION?

A. The DC Intertie [redacted] much like the Cal ISO charges, serve little or no purpose in the projected test year [redacted] The Company has not identified any transactions in the test year which require these resources. These contracts should be removed from the test year because it is unreasonable to charge customers for costs that provide no corresponding benefits. If, in actual operation in the future, these contracts provide compensating benefits, the Company could recover some of the costs via the EBA true-up. Adjustment 10 removes the cost of these contracts from the test year.

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[41] Attach 746-700,700-23.C8. See also WUTC Docket No. UE-100749, Response to ICNU DR 1.33.

[42] Attachment R746-700 23.C.8-1, Transmission Topology workpaper.

Q. HAVE REGULATORS IN OTHER STATES ADDRESSED THIS ISSUE?

A. Yes. In WUTC Docket UE-100749, regulators disallowed the costs of the DC Intertie contract on the basis that:

> PacifiCorp's evidence and arguments focus on whether the contract was prudent when it was executed. However, we do not need to answer that question in this Order. Even if we assume that the contract was prudent at its inception the Company has an ongoing obligation to manage the resource under contract to provide a benefit to the Company and its ratepayers. PacifiCorp has failed to demonstrate that it does so.[43]
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> ** *
>
> If the contract is not being used by the Company, it has an obligation to market its available transmission capacity in an effort to recover some of its costs. The Company proffers no testimony along this line. For these reasons, we conclude that PacifiCorp failed to demonstrate that the DC intertie contract would provide benefits to Washington ratepayers during the rate year. Therefore, we adopt the adjustments presented by Staff and ICNU and reduce NPC expense by $1,057,130.[44]

Likewise, in Idaho Public Utilities Commission Docket No. PAC-E-10-07, regulators disallowed the costs related to the Cal ISO charges:

> The Commission finds Monsanto's argument persuasive. The issue is what should be included in base rates. The reduced amount included in base rates does not assume the Company will not do business with Cal ISO as a counterparty. Transaction data should have been provided if the Company intended this to be a continuing forward expense. The Commission accepts the adjustment. If Cal ISO wheeling and service fees are incurred, the Company should seek recovery of costs in the ECAM.[45]

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43 WUTC Docket No. UE-100749, Order No. 6, paragraph 148, page 55. Note that the [redacted] contract was not at issue in Washington.

44 Id, paragraph 152, page 56.

45 Idaho PUC, Order 32196, pages 31-32.

<u>Adjustment 11: Non-Firm Transmission Modeling</u>

Q. HAS THE COMPANY CHANGED ITS MODELING OF NON-FIRM (NF) TRANSMISSION IN THE TEST YEAR?

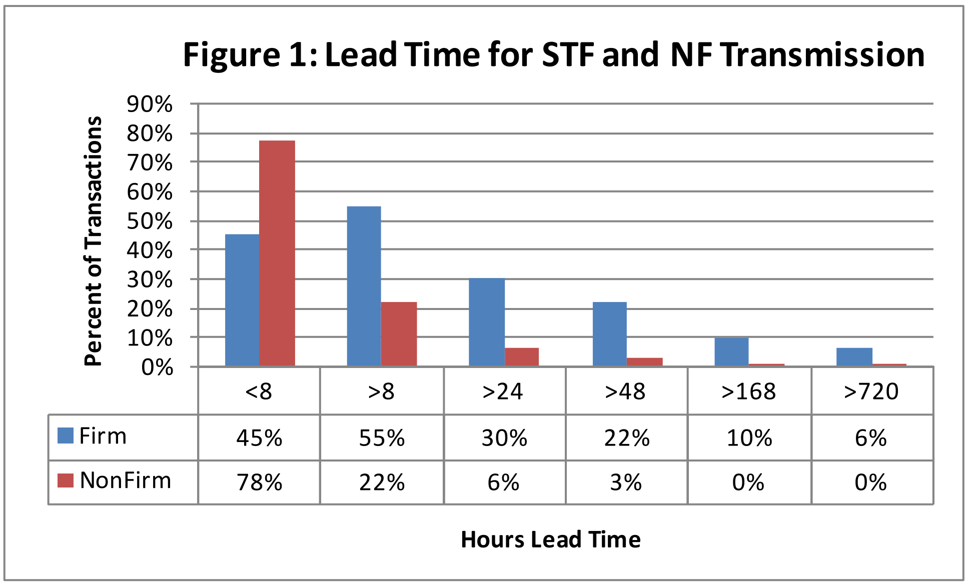
A. Yes. In prior cases the Company has used a four year average of non-firm transmission capacity and costs priced on a volumetric basis. This was first required by the Commission in Docket No. 07-035-23:

> However, since the use of non-firm transmission is normal in the operation of the Company's system, we are persuaded by the Committee's testimony on this matter and direct the Company to include non-firm transmission in the GRID model and to use an average of the 48-month history as is done in the calculation of avoided costs. (Final Order Docket 07-035-93, page 107.)

In the current case, the Company now models the capacity of non-firm transmission on the basis of the four year average while modeling the cost on the basis of the most recent historical year. The Company provides no actual justification for this change in modeling aside from an unsupported assertion that there is a similarity in the way the Company purchases and used non-firm and short-term firm transmission. This explanation is specious and fails to differentiate between the purposes of the two types of transactions.

Q. PLEASE EXPLAIN.

A. There is a substantial difference between non-firm and short-term firm (STF) transmission. Short-term firm transmission may be purchased well in advance and can be counted on for reliability purposes. As Mr. Duvall acknowledges on page 18, the non-firm transmission can be cut off for reliability purposes by the supplier. Consequently, the only value of non-firm is for economy purposes. Non-firm transmission certainly cannot be counted on for serving load. Under the Company modeling, this fact is ignored. The figure below illustrates some important differences in how Non-Firm and Short-Term Firm transmission is purchased. The figure shows that while most (55%) STF purchases occur with more than 8 hours lead time, the great majority of NF transactions (78%) are made with less than 8 hours lead time. Likewise, while some STF transactions made with a week (10%) or even a month (6%) of lead time, few NF transactions have lead times longer than a day or two.



The Company acknowledged in a recent discovery response that the major reason for non-firm purchases was for economy interchange and that such transactions are normally executed shortly before utilization.[46] As a result, in these instances the Company can easily evaluate the cost and benefit of the non-firm transmission ahead of time. In the case of STF transmission this may not be the case because the transactions may provide a reliability benefit and be made much further in advance. Consequently, the chance that the Company would make a purchase that turns out to be uneconomic is much less for NF than STF transmission.

46 See Idaho PUC Docket No. PAC-E-10-07, Response to PIIC 126 and 127.

Q. EXPLAIN WHY THE PRIOR GRID MODELING IS MORE REASONABLE.

A. The prior modeling priced non-firm transmission on a volumetric basis. This does a better job of replicating the real time situation where the operators decide whether to make a non-firm purchase in the next few hours or not. Mr. Duvall suggests that pricing on fixed, rather than volumetric basis, is superior because the Company may not use all of the non-firm capacity purchased. While that is true, I modeled the cost per MWH of transmission actually used. This will reflect actual transfer volumes (resulting in a higher price if not fully utilized) thus addressing his concern. In the Company modeling customers are charged the full cost of non-firm transmission whether it is economical to use or not. The problem is that in GRID, in many cases, it is uneconomic to purchase NF transmission at any price. In fact, utilization of the non-firm and short-term firm transmission in the test year is only 37% of the link capacity modeled.

Q. ARE THERE OTHER PROBLEMS WITH THE COMPANY'S MODELING OF NON-FIRM TRANSMISSION?

A. Yes. The Company's method is unsound because it cannot readily demonstrate any linkage between the non-firm transmission capacity costs it is including in the test year with any of the capacity links it is modeling.[47] For example, the Company made substantial NF transmission purchases from Idaho Power to wheel over Path C. With the completion of the recent transmission upgrades, such purchases are no longer needed. Absent a pro-forma adjustment, the related purchase costs would be included in GRID. While the Company did make a pro-forma in this instance, it would be very difficult to determine whether there are other circumstances where the Company has included costs in the test year that are related to NF transmission links that are no longer useful, either

[47] OCS 8.40

because the system has changed, or because market conditions have changed rendering the links unnecessary.

Conversely, the Company's modeling may include links that are being used, but without any cost being included in the test year. By modeling the links and prices on a volumetric basis it is much more feasible to produce a balanced test year.

Q. HAS THE COMPANY PREVIOUSLY OBJECTED TO CHANGING THE NON-FIRM TRANSMISSION MODELING METHODOLOGY?

A. Yes. In Docket 08-035-38, Mr. Duvall objected most strenuously to the use of a 12 month average for NF transmission inputs as opposed to the Commission's approved 48 month methodology.[48] Further, the Company recently agreed to use both a four year average cost and capacity modeling of non-firm transmission in Oregon Docket No. UE-216.[49]

Q. HAVE REGULATORS ELSEWHERE ADDRESSED THIS ISSUE?

A. Yes. In WUTC Docket No. UE-100749, the Company proposed to model non-firm transmission using the same method it now proposes in this case. In its final order the WUTC rejected the Company proposal.[50]

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission require the Company to restore the Commission accepted method for modeling non-firm transmission by adopting Adjustment 11.

<u>Adjustment 12: Transmission Test Year Adjustments</u>

Q. DOES BPA HAVE A TRANSMISSION RATE INCREASE PENDING?

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48 Docket No. 08-035-38, Duvall rebuttal pages 32-33.
49 Net Power Cost Stipulation, OPUC Docket No. UE 216, paragraph 8.f.
50 WUTC Docket No. UE-100749, Order No. 6, paragraph 175.

A. Yes. However, a decision was not made by the time of the Company's filing. While Mr. Duvall has assumed no increase will take place in the test year, he proposed to update this figure during the rebuttal phase if the final increase is known.[51] Further, Mr. Duvall has included BPA's proposed increases for reserves and wind integration charges in the test year. In none of these instances are the proposed increases known and measurable at this time.

Irrespective of whether the Company changes its view regarding this issue, a BPA rate increase should not be included in the test year, unless that cost increase is known and accurately measurable. The Company should not be allowed to simply select power cost levels based on its assumptions as to the outcome of regulatory proceedings elsewhere.

Q. PLEASE EXPLAIN.

A It is difficult to determine the exact impact of a potential rate increase, if any, without a complete rebilling of all contracts. The Company has been unsuccessful in the past in determining the actual amount of BPA's rate increases. In Docket No. 07-035-93 the Company proposed a BPA rate increase adjustment in its initial filing. However, the Company developed the escalations from a crude comparison of changes in individual rate components (from a single bill) rather than billing out the actual charges as applied to its requirements.[52] In that case, the Company was unable to produce reasonable workpapers supporting this adjustment. The Company abandoned the BPA escalation adjustment later in the case.[53] An adjustment for the BPA rate increase should only be

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[51] Duvall Direct, page 6.

[52] Telephone conference on March 26, 2008 with Dave Taylor and Hui Shu of the Company, Cheryl Murray of OCS.

[53] Docket 07-035-93, Duvall Rebuttal Testimony, pages 9-10.

allowed if the Company provides a complete rebilling of all of its BPA contracts comparing the old and new tariffs in a timely manner so that parties can verify the results well in advance of the hearing.

Q. IS BPA THE ONLY WHEELING PROVIDER TO THE COMPANY WITH AN INCREASE PENDING?

A. No. The Company has again included assumed rate increases for purchases from Idaho Power. The support for the assumed wheeling charges is the Idaho Power "Informational Filing"[54] which clearly indicates that the proposed rates are subject to FERC approval in Docket No. ER06-787.

Q. IN DOCKET NO. 09-035-23 THE COMMISSION DENIED A SIMILAR REQUEST TO INCORPORATE WHEELING RATE INCREASES INTO THE TEST YEAR. WHAT IS YOUR RECOMMENDATION?

A. These increases are not known and measurable and should not be allowed, unless final decisions are rendered well prior to the hearing date in this case, and the Company is able to produce clear cut documentation showing a rebilling of all charges under these arrangements. Adjustment 12 removes the BPA and Idaho Power wheeling rate increases the Company has assumed in the test year.

Q. ARE THERE OTHER ASPECTS OF THIS ISSUE WHICH THE COMMISSION SHOULD CONSIDER?

A. Yes. On October 21, 2008, the FERC issued an order granting PacifiCorp a 200 basis point incentive to be added to the base return on equity to be determined in a future Section 205 filing, which has to be made by June 1, 2011. The Company has committed to credit the transmission-related revenues, including the incentives granted by the FERC,

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54 Attach 746-700, 700-23.C8.

against its retail revenue requirement. Thus, the wheeling revenues incorporated in the filing will be higher once the new FERC transmission rates take effect, which will reduce the revenue requirements to the Utah retail customers. OCS 27.7 requested the Company to quantify the amount of increased revenues it expects from the FERC increase, but the response is presently outstanding. If the Commission were to allow the Company to collect the expected increased costs for pending BPA and FERC rate increases, it should also increase wheeling revenues to reflect the Company's June, 2011 increase.

Q. DOES THE COMPANY'S TEST YEAR INCLUDE REVENUES IT RECEIVES FROM TRANSMISSION IMBALANCE PENALTIES CHARGED TO THIRD PARTY TRANSMISSION CUSTOMERS?

A. No. On page 3.2 of SRM-3, the Company removes $430 thousand of transmission wheeling revenue as a normalization adjustment. In prior cases, I proposed an adjustment to recognize the effect on NPC of such penalties (whether paid to or by the Company), but the Company has opposed their inclusion. In Docket No. 09-035-23 the Commission accepted the Company proposal to exclude a normalization adjustment for transmission imbalances.[55]

Q. WHAT IS YOUR PROPOSAL?

A. Imbalance revenues occur when a third party is out of balance on the PacifiCorp system. The Company assumes that on a normalized basis, it won't collect this penalty revenue (even though in practice it generally does). The test year should either remove all such effects or include them in a consistent and even-handed manner. Consequently, the Company should also remove penalties it has paid for unauthorized use of third party transmission resources, and other related penalties. The Company failed to make these

[55] Docket 09-035-23, Final Order, page 44.

corresponding adjustments to the test year. Adjustment 12 also includes this correction ($318,758 on a Total Company basis.). Absent this adjustment, the $430 thousand wheeling revenue adjustment should be reversed.

Finally, the Company acknowledged in UIEC 13.5 that it had overstated the BPA Network transmission expense by $239,645 and that correction is also included in Adjustment 12.

Adjustments 13: Line Loss Adjustment

Q. WHAT IS THE PURPOSE OF ADJUSTMENT 13?

A. OCS witness Ms. Donna Ramas proposes an adjustment to line losses in her testimony. Adjustment 13 implements the NPC impact of this adjustment.

Q. WILL THIS ADJUSTMENT REFLECT LOSS SAVINGS FROM THE GATEWAY TRANSMISSION IMPROVEMENTS?

Q. The data she used included only a few months for 2010 where the project was complete. Consequently, her adjustment can be viewed as quite conservative. Based on my analysis (presented previously in my testimony in Docket 10-035-89), the Gateway improvements by themselves would produce annual loss savings equal to more than 75% of those assumed by Ms. Ramas, demonstrating the reasonableness of her proposal.

Adjustment 14: [redacted] Long Term Firm Transmission Contract

Q. WHAT IS THE PURPOSE OF THIS CONTRACT?

A. [redacted] While the Company includes the cost of this contract in the test year, it does not include the capacity of the link. Because the [redacted]

[redacted] as that is the opportunity cost of delivering the power elsewhere. Adjustment 14 includes this link in the GRID model. Note that if the Company argues against this adjustment, the most logical alternative is to simply disallow the cost of the contract, which produces approximately the same NPC reductions.

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F. Resource and Modeling Issues

Adjustment 15: Chehalis Reserve Capability

Q. IS CHEHALIS ASSUMED TO BE CAPABLE OF PROVIDING OPERATING RESERVES IN GRID?

A. No. In previous cases, the Company assumed Chehalis could provide reserve carrying capability. The Company now assumes that Chehalis is incapable of providing operating reserves, due to BPA's denial of the request for dynamic scheduling. BPA's website explains the basis for the denial as being due to "technical and or communications limitations." The Company has indicated this is due to lack of Automatic Generation Control (AGC) on the plant.[56] There is no reason why a modern combined cycle power plant should be incapable of providing operating reserves or that Chehalis could not have AGC installed [redacted][57] The Company made these representations when it sought approval to purchase the plant and should be held accountable for such promises.

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[56] WUTC Docket No. UE-100749, Duvall Rebuttal Testimony, page 18.

[57] Docket 08-035-35, Direct Testimony of Stefan Bird, pages 6-7, lines 129-134.

[redacted][58] However, the Company's Due Diligence analysis conducted prior to purchasing the plant (Confidential Exhibit OCS 4.11 [redacted] A more recent analysis (see also Confidential Exhibit OCS 4.10) [redacted]

Q. IS THE COMPANY'S BENEFIT ESTIMATE REASONABLE?

A. No, and it does not appear to be anything more than a guess. The GRID model results show a benefit of $2 million per year [redacted] Clearly, it would be imprudent for the Company to forego $2 million in annual benefits to [redacted] Adjustment 15 provides reserve capability for the Chehalis plant in the test year.

Adjustment 16: Station Service Modeling

Q. WHAT IS THE PURPOSE OF MODELING STATION SERVICE IN GRID?

A. All power plants use substantial amounts of energy. This usage is deducted from the output of the plant and usually factored into heat rates. When plants are off-line, some power is still being used for lighting and other equipment. It is this usage that is captured in the Company's Station Service modeling.

[58] See Confidential Exhibit OCS 4.10. Wyoming PSC Docket No. 20000-384-ER-10, WIEC 8.36-3.

Q. IS THE COMPANY'S MODELING ACCURATE?

A. No. It appears to contain three errors. First, the station service requirement for Hunter is based on 100% of the plant output, while the Company shares ownership with other utilities. The station service should be based only on the Company's ownership share. Second, the Company now models Currant Creek as a must run unit, thus eliminating nearly all offline station service.[59] Finally, the data for Chehalis was not estimated from generator logs as is the case with other plants, but rather from undocumented data from power bills from the previous supplier. The data used is consistently around twice the actual amount, raising suspicion it is in error. Adjustment 16 corrects these mistakes.

Adjustment 17: Cholla Reserve Capacity

Q. PLEASE EXPLAIN THIS ADJUSTMENT.

A. The capacity of Cholla Unit 4 was recently upgraded from [redacted] MW. However, the Company models the Cholla capacity at [redacted] MW because of a transmission limitation. In Docket 09-035-23, the Commission accepted this approach.[60] While I don't dispute the Commission's prior decision, it appears that the actual impact of the transmission limitation is to reduce the available reserve capacity from Cholla, rather than the plant's output.

Q. PLEASE EXPLAIN.

A. Cholla 4 is often used to provide reserves. The unit's maximum reserve capability is [redacted] MW. GRID's reserve allocation for Cholla 4 is at the maximum reserve capability 93% of the time, and averages [redacted] MW, or [redacted]% of the maximum reserve capability. In actual

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59 In my modeling Currant Creek also runs around the clock for several months during the test year. In a compliance GRID run, the Company could include the Currant Creek station service adjustment for months when it was not modeled as a must run resource.

60 Final Order, Docket 09-035-23, p. 45.

operation, however, the reserve allocation is much lower, averaging around [redacted] MW for 2010. Thus, it appears the GRID reserve allocation is overstated and fails to recognize it is more economic to address the transmission limit by reducing the reserve capability than by limiting the plant's output. To address this problem, I reduced the reserve capability of Cholla 4 to [redacted] MW to recognize the transmission limitation, while raising the nameplate capacity by [redacted] MW to [redacted] MW. This modeling better represents the actual reserve allocations and ensures that the operating capacity and reserve allocation for the unit is always less than [redacted] MW. Adjustment 17 implements this change.

<u>Adjustment 18: Major Market Caps</u>

Q. DID THE COMMISSION ALLOW THE COMPANY TO CONTINUE TO APPLY MARKET CAPS IN THE GRAVEYARD SHIFT HOURS IN DOCKET 09-035-23?

A. Yes. While, the Commission found in favor of retaining the market caps, it did require the Company to provide updated information in future cases to demonstrate the market caps remain relevant.[61]

Q. DID THE COMPANY COMPLY WITH THE COMMISSION'S ORDER?

A. No. Rather than demonstrate that the market caps continue to be relevant, the Company changed its market cap methodology and expanded the market caps to include all hours, not just the five hour nightly graveyard shift period. According to Mr. Duvall, the Company's expanded market caps increase NPC by $1 million.

Q. IS THERE ANY JUSTIFICATION FOR THE COMPANY'S CHANGE IN METHODOLOGY?

A. None was provided in the Company's testimony. There have always been two arguments used to support market caps in GRID – lack of liquidity in the market at night caused

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[61] Docket 09-035-23, Final Order p. 27.

"coal back-downs", and an overstatement of coal generation in GRID would ensue if market caps were not modeled. Neither argument has been supported in this case. First, the Company provides no evidence that market liquidity has declined, or that the other factors Mr. Duvall cites limit sales. Second, the market caps now are largely irrelevant as regards coal generation. Eliminating the market caps completely would reduce coal generation by only 81,000 MWH, or less than .2%. Further, the four year average coal generation in the test year is some 471 thousand *less* than the four year historical average, the metric which the Company has always used to justify market caps. Finally, even without any market caps the low load hours (LLH) coal generation is within .23% of the actual historical value. The high load hours (HLH) coal generation in the test year is 426 thousand MWH less than the historical level, a deficit of 1.7%. Based on this analysis, it makes no sense to incorporate new daytime market caps into the model.

Table 3
Coal Generation and GRID Market Caps

Scenario	HLH Coal	LLH Coal	Total
Actual 4 Yr. Avg	25,428,259	19,443,299	44,871,558
Company Base	24,991,643	19,408,451	44,400,094
Excess/Deficit	436,616	34,848	471,464
No Market Cap	24,992,932	19,488,653	44,481,585
Excess/Deficit	435,327	(45,355)	389,973
Graveyard Only Cap	24,992,932	19,440,915	44,433,847
Excess/Deficit	435,327	2,384	437,711

Q. HAS THE COMPANY JUSTIFIED THE NEW MARKET CAPS ON THE BASIS OF MARKET LIQUIDITY?

A. No. The Company has not provided any evidence of a lack of market liquidity justifying the expansion of the market caps. It is bit odd to suggest that now after many years the

Company believes the market is illiquid in on peak hours. As shown above, the HLH period has far less coal in the test year than actually occurred in the four year period. Likewise, the expansion of the nighttime market caps to include all LLH hours is unsupported. It is likely that all the Company's market cap calculation is showing is that the Company simply did not have any more power to sell into the market once coal plants became fully loaded.

Q. WHAT IS YOUR RECOMMENDATION?

A. I don't believe any market caps are justified by the Company's testimony. However, the Commission did authorize use of market caps in the limited five hour graveyard shift in the prior case. I recommend that at most, the Commission allow continuation of market caps during that period. As the table above shows, this will still produce a bit less coal generation in the test year than during the historical period. Adjustment 18 provides this correction to the test year.

<u>Adjustment 19: Bridger Fuel Price Error</u>

Q. PLEASE EXPLAIN THIS ADJUSTMENT.

A. In UIEC 4.50 the Company acknowledged an error in the price inputs for Bridger fuel. This adjustment corrects that error.

<u>Adjustment 20: Capacity Upgrades</u>

Q. PLEASE EXPLAIN THE BASIS FOR ADJUSTMENT 20.

A. In Attachment R746-700-23-C.8.h, the Company acknowledged it had failed to include certain capacity upgrades in GRID. In UIEC 4.33, the Company identified the amounts of these upgrades. Adjustment 20 includes these capacity changes.

G. Outage Rate Modeling Issues

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

A. In GRID, thermal deration factors (also called unplanned outage rates) control the amount of generation available from thermal units. The more energy available, the lower net variable power costs. If a generator has an average unplanned outage rate of 20%, GRID assumes a thermal deration factor of 80%. This means that only 80% of the unit's capacity is available to produce energy. The remaining capacity is assumed to be permanently offline. The Company computes thermal deration factors based on a four year moving average of outage rates. This calculation includes all outage events that occurred during the four year period (2006-2009). This provides a mechanism for the Company to recover costs associated with prior outages, albeit at current market prices.

Q. ARE OUTAGES AN IMPORTANT DRIVER IN OVERALL NET POWER COSTS?

A. Yes. Any increase in planned or unplanned outages increases NPC. Consequently, it is important to review all outage events to determine if they were prudent or reasonable for inclusions in the four year average.

Adjustment 21: Outage Rate Adjustments

Q. PLEASE EXPLAIN THIS ADJUSTMENT.

A. In reviewing the Company workpapers, I noticed a number of issues that tend to render the GRID outage rates unrepresentative of prudent operations or normalized conditions. These include imprudent outages, extraordinarily long outages, and outages representing conditions no longer expected to occur. I have identified several items that need to be adjusted in the Company's outage rates. While Adjustment 21 combines all of these elements, Exhibit OCS 4.2 shows the impact of each one individually.

Q. PLEASE DISCUSS THE LONG OUTAGE AT LAKE SIDE IN 2009.

A. Lake Side has [redacted] outage rate modeled in GRID. In examining the data supporting this figure, I found that more than [redacted] of the lost energy occurred [redacted]

Q. PLEASE DISCUSS THE LONG OUTAGE AT COLSTRIP 4 IN 2009.

A. A problem was discovered during the 2009 planned outage of Colstrip 4, which prevented the units' return to service in May. The outage extended for [redacted] before the equipment could be repaired. This [redacted] of the lost generation at the plant in the entire four year period. As a result, the Company computes an average outage rate for Colstrip 4 in excess of [redacted] For 2009 this equates to an outage rate in [redacted] for the unit.

Q. SHOULD THE ENTIRE DURATION OF THESE EVENTS BE REFLECTED IN THE TEST YEAR?

A. No. These were extremely rare events and quite unlikely to recur once every four years, as is assumed in the Company's four year moving average calculation. It is very unlikely that these events are representative of conditions in the rate effective period. As a result, including these events in the test year outage rate will produce an inaccurate forecast.

Q. HAS THIS ISSUE BEEN CONSIDERED BY REGULATORS ELSEWHERE?

A. Yes. In Oregon regulators have used an approach that caps outages at 28 days. This approach was required in Oregon after the 2007 power cost update case, UE 191.[62] More

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62 The Oregon order states: "The Company documents show that the anticipated duration of the resulting outage was five to seven weeks. An outage of that duration, no matter what the cause, is anomalous, and

recently, in Oregon Docket UM 1355 (a generic investigation into methods to improve outage rate forecasts) the OPUC implemented a new outage rate forecasting method that also retains a 28 day cap, as part of a much more complex method.[63] In WUTC Docket No. UE-100749, regulators decided to adopt a rather similar adjustment replacing the long Colstrip outage with a more typical outage rate during that period. The WUTC made the adjustment on the basis it would improve forecast accuracy.[64]

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission limit the long 2009 Lake Side and Colstrip outages to 28 days. I would have no objection to using a method that simply replaces the lost energy during those events with the average amount of outage energy during the remainder of the period.

Q. PLEASE DISUCSS THE APRIL, 2009 NAUGHTON 3 OUTAGE EVENT.

A. Recent discovery requests[65] concerning this event demonstrate that the Company's contractor, [redacted] According to the Company, [redacted]

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raises issues regarding its inclusion in normalized rates. In this case, we find that a 28-day period is a reasonable limit on the length of the outage for the purpose of calculating the TAM adjustment factor. To the extent the actual outage exceeded 28 days, the Company should make an appropriate adjustment to the outage rate used in running the GRID model." OPUC Docket No. UE 191, Order 07-446 at 21 (Oct. 17, 2007).

63 OPUC Docket UM-1355, Order 10-414, page 5. The Oregon method now applied would likely produce lower outage rates for Colstrip 4 and Lake Side, were it applied here.

64 WUTC Docket No. UE-100749, Order No. 6, paragraph 140, page 53. Note that the Lake Side outage was not at issue in Washington because Lake Side is not recognized in rates on other grounds.

65 OPUC Docket No. UE-216, Response to ICNU 2.3

[redacted] Because the Company was [redacted], imprudence and/or negligence is not debatable. [redacted] Consequently, I made adjustments to both planned and forced outages to remove the impact of this event.

Q. PLEASE DISCUSS YOUR RECOMMENDED CHANGE TO THE CHOLLA 4 OUTAGE RATE.

A. From July 2006 through March 2008, Cholla 4 was frequently unable to achieve full capacity. In spring 2008, during the plant overhaul the problem was resolved and the plant was returned to full capacity. The associated costs have been included in the overhaul expense used in the test year and the Company does not expect the problem to occur again.[66] Adjustment 21 removes the impact of this event from the Cholla 4 outage rates used in the test year.

Q. WERE [redacted] RECEIVED BY THE COMPANY RELATED TO OUTAGES AT THE BRIDGER PLANT?

A. Yes[redacted] However, there were no Root Cause Analysis (“RCA”) reports for these events[redacted][67] [redacted] Further, the lack of any RCA reports indicates prudence

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66 See Wyoming PSC Docket No. 20000-384-ER-10, WIEC 12.9 and 12.10. The Company uses the same steam overhaul expense level in both the current Wyoming and Utah proceedings.

67 See Wyoming PSC Docket 20000-384-ER-10, WIEC 1.22.

cannot be established by the Company. As a result, I have removed the impact of these events from the test year.

Q. CAN FUEL PROBLEMS CAUSE GENERATOR OUTAGES OR DERATIONS?

A. Yes. Fuel problems can result in a reduction to capacity, or a complete shutdown of a plant. Some problems, such as frozen or wet coal are caused by bad weather and may be beyond the Company's control. However, fuel quality testing is a normal practice at all power plants and is intended to prevent output reductions, violation of air quality standards or damage to power plants. Utilities report to North American Electric Reliability Council ("NERC") the instances where fuel quality problems result in lost energy due to outages or derations.

Q. DOES IT APPEAR THAT PACIFICORP HAD PROBLEMS WITH FUEL QUALITY AT BRIDGER?

A. Yes. There were an inordinate number of derations at the Bridger plant related to fuel quality problems. Review of data from 2006-2009 shows that on average, the Company lost far more energy due to fuel quality issues at Bridger than any other plant. In fact, 94% of all energy lost due to fuel quality problems occurred at Bridger. Bridger fuel quality losses are more than twice the NERC average for comparably sized plants.[68]

Q. WHAT IS YOUR RECOMMENDATION?

A. Bridger coal is produced at a Company-owned captive mine. The level of fuel quality losses is excessive and both the production of coal and the operation of the plant are under the Company's direct control. In recent testimony, the Company has indicated

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[68] The NERC figures include weather related events such as frozen coal, which I have eliminated, so the comparison is even more unfavorable to Bridger.

steps are being taken which will improve the quality of Bridger coal.[69] I recommend the Commission remove the additional costs resulting from this problem both to reflect a reasonable level of costs and as an incentive for the Company to resolve the issue. As the Company is already working to improve the coal quality, this is a reasonable adjustment.

Q. ARE THERE OTHER OUTAGE CONCERNS RELATED TO THE BRIDGER PLANT?

A. Yes. For years Bridger has experienced a much higher rate of outages and derations due to employee errors. The plant is responsible for more than 60% of all PacifiCorp lost energy due to employee errors and the outage rate is more than twice the NERC average.

I recommend the Commission reduce the outage rates used for Bridger to remove the extra output lost resulting from liquidated damages payments, impute improved fuel quality and reduce error outage to match the NERC averages. This is also included in Adjustment 21.

Q. ARE THERE OTHER UNREPRESENTATIVE EVENTS INCLUDED IN THE COMPANY'S OUTAGE RATE CALCULATIONS?

A. Yes. The Company has included several reserve shutdown periods for coal and combined cycle gas plants. Because GRID schedules the gas plants (using the screening adjustment) it is unnecessary to increase outage rates to reflect reserve shutdowns. Reserve shutdowns for coal plants seem quite unlikely now because market prices have increased and coal generation needs to be on line to provide reserves for wind integration. Adjustment 21 also removes the impact of reserve shutdowns for combined cycle gas plants and coal generators.

Q. ARE THERE ANY OTHER ISSUES RELATED TO THE OUTAGE RATES?

[69] Idaho Public Utilities Commission Docket PAC-E-10-07, Rebuttal Testimony of Cindy Crane, page 9-12.

A. Yes. The Company has modeled the Gadsby CT as must run units. As a result, there are no reserve shutdowns for this plant. I accepted the Company's $EFOR_d$ outage rate calculation because this is the best way to model units with substantial reserve shutdowns. However, if the Commission accepts the Company's must run modeling, it should not apply the $EFOR_d$ outage rate, but instead use the conventional formula. Likewise, if the must run modeling of Currant Creek is accepted by the Commission, the removal of reserve shutdown events for that plant is correct irrespective of whether the Commission adopts Adjustment 21 for other plants or not.

Adjustment 22: Heat Rate Modeling Adjustment

Q. WHAT IS THE PURPOSE OF ADJUSTMENT 22?

A. This adjustment corrects heat rates so they are not artificially inflated due to the deration of unit maximum capacities used to model forced outages in GRID. A modeling technique designed to eliminate this problem is already used by at least one other regional utility, Portland General Electric ("PGE"), in its power cost model, MONET. I believe this represents standard industry practice, as do other experts. For example, in Docket No. 07-035-93, another power cost modeling expert, Mr. Philip Hayet, testified that the technique is well accepted in the community of production cost modeling experts.[70] Further, this technique was recommended for application to PacifiCorp by OPUC Staff witness, Kelcey Brown in OPUC Docket UM 1355.[71]

Q. WHY IS AN ADJUSTMENT NECESSARY?

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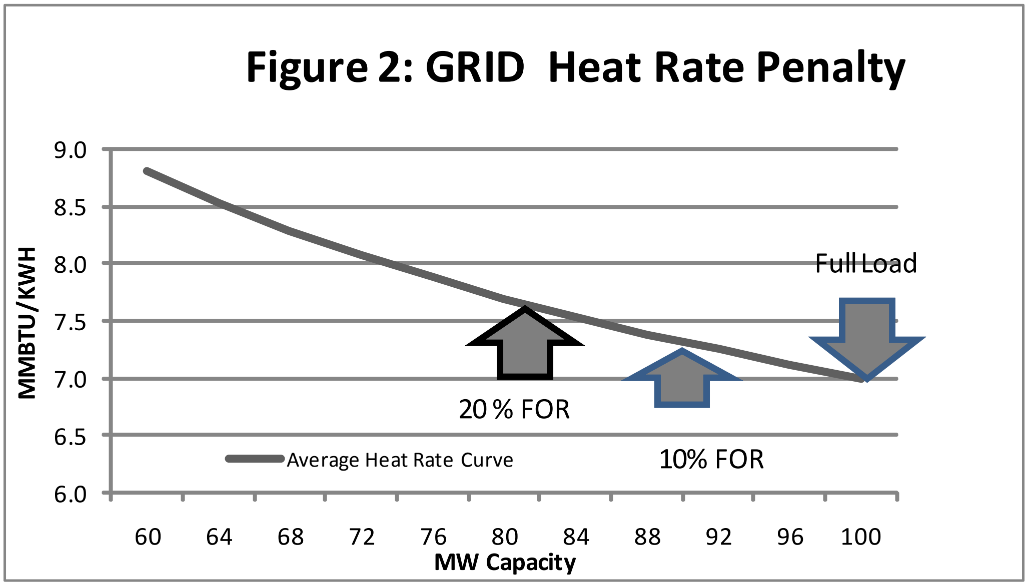
70 Docket No. 07-035-93, Direct Testimony of Philip Hayet, Exhibit No. CCS 5D at 25 (April 7, 2008).

71 OPUC Docket No. UM 1355, Supplemental Reply Testimony of Kelcey Brown, Staff Exhibit No. 300 at 20 (August 13, 2009).

A. In GRID, forced outages are modeled by "shrinking" the capacity to account for outages. For example, a 100 MW unit with a 20% forced outage rate is seen as an 80 MW unit in GRID.

A problem with the GRID modeling is that when the capacity of units is derated to model outages, there is a mismatch with the "full size" heat rate curve. The Company would apply a heat rate curve sized for a 100 MW unit to the now "shrunken" 80 MW unit. Much like driving a car 60 miles per hour in 3rd gear, this is inefficient. The figure below shows what happens when a heat rate curve sized for a 100 MW unit is applied to the derated 80 MW unit. The unit artificially "moves up the heat rate curves" and efficiency appears to be reduced. As the forced outage rate ("FOR") increases for a unit, its heat rate normally increases in the GRID modeling. This, however, is highly unrealistic, as lengthening the period of a forced outage should have no effect on the units' average heat rate. The GRID method "rewards" the Company for having high outage rates by artificially inflating the heat rate. This is a "win-win" for the Company and a "lose-lose" for customers.



Q. IS THIS PROBLEM PRESENT IN THE COMPANY'S GRID RUN?

A. Yes. When the long outage for Colstrip 4, which I discuss above, was removed from the GRID database, the average heat rate for the plant decreased from 10,734 BTU/KWH to 10,676. In other words because the long Colstrip outage *increased* the forced outage rate, the GRID model assumes a *reduction* in the efficiency of the unit when it is running. However, it makes no sense that the time spent when a plant is sitting idle should have an impact on its average heat rate. The fact that it does so in GRID is proof that this problem is real. In GRID, Colstrip 4 runs at full loading virtually every hour of the year. There is no reason why its heat rate should increase just because the plant has a higher forced outage rate.

Q. THIS ISSUE WAS LEFT OPEN IN THE FINAL ORDER IN THE 2009 GRC.[72] DID MR. DUVALL ADDRESS THE COMMISSION'S CONCERNS?

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72 Final Order, Docket No. 09-025-23, P. 57.

A. No. His testimony did not address the approach the Commission discussed in its order in that case. Nor did the Company participate in the process suggested by the Commission for the parties to investigate this matter. Further, his characterization of the events surrounding the DPU's proposed workshops is inaccurate and frankly very troubling to OCS. An initial meeting was held with the Company, DPU and OCS to discuss alternatives for investigation. In a prior case involving planned outage scheduling, the Company declined to provide the analysis requested by the DPU that it had earlier committed to perform on the basis that the issue was being litigated in other states. OCS was concerned that the same thing would happen and raised the matter with the Company and DPU at the initial meeting. The Company indicated that it would not let that stand in the way of examining the issue. Consequently, OCS prepared an analysis to address the issue and was prepared to provide it to the parties. OCS was informed that the Company had done the same. However, when the time came to schedule the meeting to present OCS and Company proposals the Company backed out and stated the matter could not be discussed because of litigation in other states. OCS was more than willing to meet with the DPU and Company regarding this matter, and contrary to what Mr. Duvall claims did in fact prepare its analysis as agreed. It is very troubling to the OCS that it has in good faith undertaken to cooperate on issues such as planned outage scheduling and the heat rate modeling adjustment only for the Company to refuse to participate in a good faith effort.

Q. DID THE FACT THAT THIS ISSUE WAS BEING LITIGATED ELSEWHERE POSE A PROBLEM FOR THE COMPANY?

A. No – instead it was advantageous to the Company. In both the 2010 Idaho and Washington proceedings I provided the Company alternative analyses pertinent to the issue. Consequently, the Company had a "preview" of the OCS analysis that further examined the validity of the adjustment. Why this would be a detriment to conducting an investigation of the matter is unclear.

Q. HAS MR. DUVALL CONCEDED THE VALIDITY OF AT LEAST PART OF THE HEAT RATE MODELING ISSUE?

A. Mr. Duvall's recent Wyoming testimony acknowledged validity to this adjustment when GRID simulated units running at their derated maximum capacity, though he disagrees with the application of this adjustment at lower capacity loadings.[73] As shown above in the Colstrip example, GRID heat rates are biased by the outage rate modeling technique.

Q. CAN YOU ILLUSTRATE THIS PROBLEM FURTHER USING COLSTRIP AS THE EXAMPLE?

A. Yes. The Confidential table 4 below illustrates the problem. It shows the heat rate equation used in GRID for Colstrip Unit 4. Based on the data used in GRID, the capacity of Unit 4 is [redacted] However, there are partial outage derations that occur, that lower the available capacity to [redacted] on average, or Partial Forced Outage Rate ("PFOR") of [redacted]%. These events do not result in shutdown of the plant, but do degrade the average heat rate in the field and should do so in GRID as well. Based on the average [redacted] capacity loading, the heat rate for the unit is [redacted] MMBTU/MWh.

In GRID, however, full forced outages are assumed to reduce the maximum available capacity of the unit by an additional [redacted], resulting in a maximum derated capacity in GRID of [redacted] MW and an Equivalent Forced Outage Rate ("EFOR")

[73] Wyoming PSC Docket No. 20000-384-ER-10. Duvall Direct, page 31

of [redacted]%. When the GRID heat rate curve is applied, the result is [redacted] MMBTU/MWh. When the Colstrip fuel cost difference is applied to the difference between the two heat rates, the resulting error is close to $168 (or $16.8 for the Company's 10% share.) This may seem like an inconsequential amount; however, this problem occurs thousands of hours per year for nearly every unit and can become a substantial sum of money.

Table 4: Confidential Example

[redacted]

<u>GRID Based Analysis</u>

Q. IN THE FINAL ORDER IN DOCKET NO. 09-035-23, THE COMMISSION DISCUSSED AN ALTERNATIVE METHOD FOR ADDRESSING THIS ISSUE. HAS THE COMPANY COMPLIED WITH THE COMMISSION ORDER?

A. No. At page 57, the Order states:

> We direct the Company, Division and other interested parties to review alternatives for addressing this issue, review actual operations in comparison to modeling predictions, and to understand the extent of the issue. *For example, one alternative could be proportionally adjusting or compressing the heat rate curves*

> *so when a plant is running at its full derated capacity it will have a heat rate associated with the non-derated full capacity,* and when it is running at its minimum capacity the heat rate will be the non-adjusted minimum one. (emphasis added.)

Mr. Duvall stated he did not prepare any analysis to address the Commission's order because he did not agree with the adjustment.[74]

Q. HAVE YOU PREPARED AN ANALYSIS RESPONSIVE TO THE ORDER?

A. Yes. Based on the portion of the Order quoted above, it appears the Commission is persuaded that at least at the top of the heat rate curve, GRID misstates the heat rate due to the capacity deration for the reasons discussed above. As noted above, Mr. Duvall has also acknowledged that problem. Consequently, I have prepared an analysis intended to address this problem by itself in lieu of the entire adjustment litigated in prior cases. This could then be used as a financial adjustment computed outside of the GRID model, simplifying the process.

In order to perform this analysis as efficiently as possible, I prepared a special GRID run ("PFOR Only") based on the Test Year GRID study. In the example above, the GRID input would be [redacted]% for the Colstrip 4 outage rate, rather than the conventional [redacted] All units were modeled using only the appropriate PFOR input in this run. The only purpose of this run was to compute the average heat rate at the highest possible loading in GRID when partial outages were modeled. This is equivalent to the [redacted] figure shown above. The average fuel cost for hours when the units were dispatched to their maximum was then computed in a pivot table.

From the base case run I created another pivot table in which the hours when units were dispatched to their maximum capacity (with the full EFOR modeled, equivalent to

[74] Duvall Direct Testimony, page 31.

the [redacted] MW figure in the example above) were determined. The average fuel costs for these hours was computed and compared to the average fuel cost from the run with only the PFOR modeled. The increase (or decrease) in average fuel costs between the two runs was then applied to the hourly unit loading in the base case to determine the hourly adjustments. The hourly adjustments were then summed to produce the total adjustment. In effect, the comparison of the two runs was simply to automate the process shown in Table 4 above, and to compute the hours when the adjustment would be applicable (i.e. the fullest possible loading of the units.)

The final results show that the total adjustment under this approach amounts to approximately $1.4 million on a Total Company basis computed against the Company's base case. I would point out that this is likely to be a very conservative adjustment because it only addresses misstatement of the heat rate at the full derated loading, and makes no adjustment when the loading is close to the full derated capacity.

Q. HOW DOES THIS ADJUSTMENT DIFFER FROM THE ADJUSTMENTS YOU PROPOSED IN THE PAST THREE UTAH GENERAL RATE CASES?

A. This adjustment includes only the component of the adjustment related to addressing the problem at the top of the heat rate curve. As discussed above, the Order in Docket 09-035-23 and Mr. Duvall's prior testimony lend credence to at least this part of the adjustment.

Q. THIS ISSUE HAS BEEN LITIGATED IN OTHER STATES. WHAT HAVE REGULATORS ELSEWHERE DECIDED?

A. In its recent order in Oregon Docket UM 1355, the OPUC adopted the adjustment I proposed in Docket 09-035-23, incorporating both the heat rate adjustment and minimum loading deration.[75] Further, Washington regulators have also adopted the same adjustment in its most recent decision.[76]

Adjustment 23: Balancing

Q. WHAT IS THE PURPOSE OF ADJUSTMENT 23?

A. Adjustment 23 provides a placeholder for the final balancing impact of the Commission approved adjustments in my proposed final GRID run and their effect on the final screens.

Q. WHY IS THIS IMPORTANT?

A. When adjustments are combined there is an overlap effect. In some cases, adjustments combine to produce a larger effect than they would individually, while in other cases, the reverse is true. In Docket 10-035-13, I performed a GRID run which implemented all of the Commission approved adjustments from Docket N0. 09-035-23. In that case, I determined that there should have been an offset of $647,779 (Total Company) when all of the approved adjustments were combined.[77] While in that instance, ratepayers were disadvantaged by the lack of a compliance GRID study, the reverse could happen as well. Consequently, in order to provide the fairest possible final NPC result, I recommend the Commission require the Company to file a compliance GRID study either in this case or if there is insufficient time to provide a final run with all adjustments in this proceeding, the final run could be performed and used as an offset or adjustment to the NPC baseline in the initial EBA case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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[75] OPUC Docket No. UM 1355, Order 10-414, page 7.
[76] WUTC Docket No. UE-100749, Order No. 6, paragraph 191, page 68.
[77] OCS Exhibit 3D, Docket No. 10-035-13, page 2.