Witness CCS 4SR

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, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval Of a New Large Load Surcharge	)))))))))	**Docket No. 07-035-93** **Surrebuttal Testimony of Randall J. Falkenberg On Behalf of the Utah Committee of Consumer Services**

May 23, 2008

REDACTED

Redacted Confidential Material is highlighted in gray.

SURREBUTTAL TESTIMONY OF RANDALL J. FALKENBERG

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350. I am the same Randall J. Falkenberg who pre-filed direct testimony in this docket on April 7, 2008 and rebuttal testimony on May 9, 2008.

Q. PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY.

A. My surrebuttal testimony makes the following points. All figures are on a Utah basis:

1. The Company's comparisons of my GRID results to actual cost are incorrect and misleading. The Commission should give them no weight.

2. Mr. Duval's criticism of my workpapers is unfair because the Company failed to file timely data requests. The Committee expedited its response to the Company's request for workpapers and offered to explain them to the Company.

3. I continue to support my commitment logic adjustments and non-firm transmission recommendation.

4. My proposed planned outage schedule is the most reasonable alternative in this case. I demonstrate it produces results nearly identical to a composite of four GRID studies using the <u>Company's actual planned outage schedules</u> from the four-year period.

5. I continue to support my heat rate modeling and minimum loading deration adjustments.

6. I continue to support elimination of the monthly outage rates, and demonstrate why the Commission to reject Mr. Duval's new proposal to eliminate the weekday-weekend outage rate split.

7. I reduce the Ramping Adjustment (CCS 4.19) by $636 thousand, using actual ramp rates to establish the ramping included in the EFOR.

8. I show that Mr. Duval's characterization of certain CCS and DPU adjustments as "updates" or "new information" is a misleading attempt to justify inclusion of

new costs and a selective update of data favorable to the Company. I recommend these adjustments be made without the forward curve update.

9. Because the Commission invited the Company to update its filing at the time of the test year change, it should reject Mr. Duval's proposed inclusion of new costs and the forward curve adjustment. If the Commission allows the forward curve update, I recommend it also require the Company to reshape the hydro energy in GRID to reflect the new forward curve.

10. I correct an error in the Call Option (CCS 4.5) adjustment, decreasing NPC by approximately $457 thousand.

11. I withdraw the STF Arbitrage and Trading Profits (CCS 4.13) adjustment.

12. I continue to support the Committee's SMUD re-pricing and normalization adjustments.

13. I withdraw the Proper Hydro Weighting Adjustment (CCS 4.15) and instead recommend the Commission require the Company to file a complete 40 water year simulation in its next general rate case.

14. I withdraw the Bridger Outages (CCS 4.18) and Station Service in Heat Rates (CCS 4.24) adjustments.

15. I make a correction of $102 thousand reducing the Self Supply Owned Reserve (CCS 4.26) adjustment.

16. I reduce the Wind Integration adjustment by $188 thousand.

17. I accept the DPU Adjustment 6.3 related to the Kennecott and Tesoro contracts.

18. In summary, my revised NPC recommendation is $1,002 million total Company resulting in a reduction to the Company's originally filed request of $48.7 million. Total recommended adjustments reduce Utah allocated NPC by $20.5 million.

Revisions to NPC Recommendations

Q. HAVE YOU REVISED AND UPDATED YOUR RECOMMENDATIONS PRESENTED IN TABLE 1 OF YOUR DIRECT TESTIMONY?

A. Yes. In light of the Company's rebuttal, I have made a number of revisions and changes to the recommendations I made in my direct testimony. The table below shows the changes from my direct testimony.

Table 1 Surrebuttal
Adjustments and Corrections to Table 1

			Total Company	Est. Utah Jurisdiction
			SE	41.70%
			SG	42.48%
I. GRID (Net Variable Power Cost Issues)				
		1 PacifiCorp Request NPC - GND-15	**1,050,698,899**	
CCS Direct Case Adjustments to NPC			**(59,450,639)**	**(25,023,369)**
CCS GRID Result Direct Case			**991,248,260**	
Revisions to Direct Case				
CCS4.5	**Reverse**	**Call Options - Direct**	**2,502,690**	**1,053,407**
CCS4.5S	**Include**	**Call Options - Surrebuttal (Correction)**	**(3,587,460)**	**(1,509,998)**
CCS4.13	**Reverse**	**STF Arbitrage and Trading Profits**	**3,584,812**	**1,508,883**
CCS4.15	**Reverse**	**Proper Hydro Weighting**	**3,471,982**	**1,461,392**
CCS4.18	**Reverse**	**Bridger Error Outages**	**1,249,330**	**525,855**
CCS4.19	**Reverse**	**Ramping**	**3,981,680**	**1,675,929**
CCS4.19S	**Include**	**Maximum Ramping - Surrebuttal**	(2,471,712)	**(1,040,368)**
CCS4.24	**Reverse**	**Station Service in Heat Rate Curve**	**1,523,178**	**641,121**
CCS4.25	**Reverse**	**Wind Integration Charges - Direct**	**1,690,147**	**711,400**
CCS4.25S	**Include**	**Wind Integration Charges - Surrebuttal**	(1,242,997)	***(523,190)***
CCS4.26	**Reverse**	**Remove Self Supply Non-Owned Reserve - Direct**	**2,186,441**	**920,295**
CCS4.26S	**Include**	**Remove Self Supply Non-Owned Reserve - Surrebuttal**	(1,945,285)	**(818,790)**
DPU6.3	**Include**	**Kennecott and Tessoro Adjustments**	(225,498)	**(94,914)**
Total Revisions			**10,717,308**	**4,511,022**
CCS Surrebuttal Case Adjustments to NPC			**(48,733,331)**	**(20,512,346)**
CCS GRID Result Surrebuttal Case			**1,001,965,568**	

Comparison to Actual Costs

Q. DO YOU HAVE ANY COMMENTS CONCERNING MR. DUVAL'S TESTIMONY COMPARING YOUR RECOMMENDED TEST YEAR NET POWER COSTS TO THE COMPANY'S MOST RECENT ACTUAL NET POWER COST RESULTS?

A. Yes, I have several comments. First, while he is ostensibly criticizing my testimony, in reality, I believe Mr. Duval is re-arguing the Commission's decision to use the 2008 test year. The disparity between recent actual costs and GRID model results has much more to do with the many differences that exist between the Commission's 2008 test year and the circumstances that occurred during the historical period, than it has to do with the adjustments that I recommended be made to the Company's GRID modeling. The fact that Mr. Duval made no attempt to examine the differences between the 2008 test year and the historical period he cites, is unfortunately, quite misleading.

Second, the suggestion that unaudited and unadjusted actual cost provides a reasonable benchmark for ratemaking purposes is highly debatable. The use of actual costs has come up in Utah and in other states as well in the past, but hasn't been applied in Utah for many years. Nor has the Company consistently advocated use of actual cost. The Company apparently perceives a benefit (in terms of reduced regulatory lag) from the use of projected test years rather than historical actual costs and supported changes to legislation that enabled the expanded use of projected test years. It should not be now allowed to select the higher of historical actual or projected normalized.

Third, it is important to recognize that if actual costs are to be used, they would still need to be audited and normalized for ratemaking purposes. Use of "normalized actual" costs would not be an endeavor free of controversy. There are many differences in the system between recent historical periods and the rate effective period. There would be substantial disputes concerning not only the normalization of actual costs, but also the prudence of those costs. Mr. Duval's suggestion that the Commission should now place reliance on the most recent 12 months of actual costs (which has never been subjected to audit and which clearly fails to reflect numerous known differences between the historical period and the rate effective period) is little more than an attempt to "change the subject" (if not the test year) from the relevant issues in this case, to something else the Company would rather focus on.

This should not detract the Commission from the real issues of this case. Much of the recent increase in actual power costs has been due to higher than expected load growth. Mr. Duval makes little mention of this fact. The main problem resulting in higher than expected power costs lies with the Company's own load forecast (which I used), not my GRID model results, or prior Commission decisions. However, if the Company were to increase its sales forecast in GRID, it would also have to increase its revenue forecast, billing units, and jurisdictional allocations factors. All of this has been ignored by Mr. Duval.

Fourth, Mr. Duval's apparent suggestion (based on GND-2R-RR) that because the Company believes it has undercollected net power costs in the past (2001-2007), it should be now given a more sympathetic ear by the Commission in this case is also specious. The Company has not challenged whether past rates were just and reasonable. Thus, this argument has no merit. The Commission must set rates in this case based on evidence presented in this case, not reconsider prior (mostly settled) cases.

Finally, this is not the first time the Company has tried to "change the subject" by making dubious comparisons between test year normalized and recent actual power cost results. In the 2001 rate case, Mr. Duval's predecessor, Mr. Widmer, also presented a "last minute" appeal to actual NPC results in his rebuttal testimony, which he contended showed that criticisms to the Company's study were unfounded:

> "During 2000 the Company experienced significantly higher purchased power prices as a result of the western energy crisis. As a result, 2000 actual net power costs were approximately $833 million on a Total

Company basis compared to the Company's current proposed net power costs of $806 million, or almost double the amount included in rates.

Q. Does the Company expect net power costs to decline substantially from these levels during 2001?

A. No. Actual net power costs for the first four months of 2001 totaled $372 million. On an annual basis, the Company's 2001 net power costs were forecasted to be approximately $760 million on a Total Company basis in a February 2001 forecast. However, it should be noted that FERC recently placed a cap on wholesale energy prices that has resulted in much lower market prices today and through the remainder of the year, based on current expectations. Unfortunately, the Company's previously executed forward purchases are now higher priced than the current forward price curve. *This has effectively eliminated the prior expected benefits of the Company's forward purchases, which had the effect of driving the lower expected net power costs for the second half of 2001, referred to by Mr. Falkenberg on page 10 of his testimony. As a result, the Company now expects net power costs to be substantially higher than the $760 million previously forecast.* (Docket No. 01-035-01, Rebuttal Testimony of Mark Widmer, page 5.)

The Commission's final order did not rely on that analysis in the 2001 case. Instead the Commission concentrated on the actual issues at hand, selecting a NPC result that provided its best evaluation of the conditions appropriate to the test period, even though the final result was less than the recent actual cost results.[1]

Q. ON PAGE 7 OF HIS TESTIMONY, MR. DUVAL SAYS IT WAS UNREASONABLE FOR YOU TO RECOMMEND A NET POWER COST RESULT FOR THE 2008 TEST YEAR THAT IS $38 MILLION LESS THAN THE ACTUAL NPC FOR THE MOST RECENT 12 MONTH. IS HIS CONTENTION VALID?

A. No. The $38 million disparity he cites results largely from my use of the test year approved by the Commission, the Company's GRID model and its load forecast. As far as the comparison to actual cost, I'd point out that the result I presented in

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[1] Mr. Widmer's comparisons failed to include the Hunter outage, which accounted for a large portion of the differences, and much like Mr. Duval's presentation was highly misleading.

direct testimony, $991 million, exceeds PacifiCorp's actual 2007 NPC by approximately $16 million. My adjustments are appropriate corrections to problems with the Company's modeling. Further, I have now increased my recommended NPC result, by more than $10 million.

Q. PLEASE DISCUSS MR. DUVAL'S COMPARISON TO ACTUAL RESULTS FOR THE 12 MONTHS ENDED MARCH 31, 2008.

A. There are many reasons why these recent actual net power costs are much different from the 2008 test year GRID results. Table 2 below attempts to capture the most important differences between my 2008 GRID test year, and the Company's twelve month ending March 31, 2008 actual results. It shows the changes in energy in both load and resources between the test year that I used and Mr. Duval's historical period. To make our figures comparable, substantial changes to either actual costs, or GRID results would be needed. My estimate of these required cost changes applied to my GRID study are shown in the table as well. Naturally, it is difficult to quantify these impacts, but the figures below represent acceptable estimates.

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Surrebuttal Table 2

	Actual 3.31.2008	GRID 12.31.2008	Difference	Cost Impact
Load Change	59,072,835	58,505,214	-567,621	59,873,043
Hydro Difference	5,714,924	6,410,990	696,066	34,230,110
LakeSide	1,959,810	2,889,432	929,622	33,033,258
TransAlta	845,664	0	-845,664	-14,147,988
SMUD Contract	465671	350400	-115,271	9,448,580
Blundell	165,673	272,753	107,080	4,722,211
Wind Generation	700,427	1,062,885	362,458	20,841,329
Gas Prices	N/A	N/A	N/A	-45,741,145
Coal Prices (Negligible)	N/A	N/A	N/A	N/A
			Total	**102,259,399**
		RJF Final Result		**991,248,260**
		Adjusted Result		**1,093,507,659**

First, the 2008 test year modeled in GRID reflects lower loads than actually occurred in the 12 month ended March 31, 2008 period. In fact, based on the figures shown in GND 3R-RR, there was 567,621 more mWh for the 12 months ended March 31, 2008 as compared to the calendar year 2008 test year. I could not rerun GRID using the higher load numbers because I did not have the hourly load data. However, Mr. Duval already provided an estimate of the change in GRID power costs resulting from a change in loads in GND-5R-RR. Applying his results would support an increase in NPC of almost $60 million in my projected GRID result. It should be fairly clear that my GRID results would be much higher had I used the actual loads for the recent historical period. Mr. Duval makes no mention of this fact. It should be pointed out, that I simply used the test year loads prepared by the Company for its 2008 test year. I made no changes to the native customer load data used in GRID.

Q. IS THIS THE ONLY DIFFERENCE BETWEEN ACTUAL RESULTS AND YOUR GRID STUDY?

A. No. I'm sure Mr. Duval realizes that the Lake Side plant came on-line several months late. Lake Side did not begin full operation until September 8, 2007. Thus, the 12 months ended March 31, 2008 NPC report used by Mr. Duval, would include the plant for only about half of the period. My study, of course, assumed Lake Side would be online for the entire period. If I had only used six months of Lake Side production, my study results would have been $33 million higher. Again, this significant difference between actual results and my GRID study has nothing to do with any adjustments I proposed.

Q. DOES THE LAKE SIDE IN SERVICE DATE ISSUE ALSO ILLUSTRATE OTHER MATTERS CONCERNING THE USE OF ACTUAL COST?

A. Yes. Were the Commission to rely solely on actual costs it should find out why the Lake Side unit did not come on line in time for the summer 2007 peak period. Were the Commission to rely solely on actual costs (as in a PCA) it should find out why the Lake Side unit did not come on line in time for the summer 2007 peak period and remove any imprudent costs resulting from higher purchased power costs that were required. However, Utah uses normalized rather than actual costs. If "normalized actual costs" were being used, then the Commission should remove the $33 million in higher replacement power costs resulting from the delay of Lake Side.

Q. WHAT OTHER DIFFERENCES EXIST BETWEEN MARCH 2008 ACTUALS AND YOUR GRID STUDY?

A. Based on the actual power cost reports, hydro generation was below the GRID normalized hydro forecast for 2008. The 2008 GRID study I used has nearly 700 thousand more mWh of hydro generation than the actual results for the twelve months ended March 31, 2008. While I did propose a minor adjustment to hydro modeling, it changed the overall hydro generation by a very little. Reflecting the actual hydro conditions for the historical period would increase my NPC result by an additional $34 million. As with the other issues, I again, relied almost exclusively on the Company's hydro inputs to GRID and the Commission's test year.

Further, wind generation is increasing rapidly on the system. Wind generation is expected to increase by more than 360 thousand mWh between the 12 months ended March 2008 period Mr. Duval used and the 2008 test year approved by the Commission. Had I used the historical wind generation in my GRID study, NPC would increase by an additional $20 million. Also, generation from the low cost Blundell geothermal plant is increasing in 2008 by more than 100 thousand mWh. Had I reflected lower generation for this plant in the test year, NPC would have increased by $5 million.

Q. DID THE COMPANY ADJUST THE SMUD CONTRACT IN THE ACTUAL NPC REPORTS TO MATCH THE RATEMAKING TREATMENT USED BY THE COMMISSION?

A. No. In the actual report for 2007 cited by Mr. Duval, the Company did not do so. However, for ratemaking purposes, the Commission has historically used a $37/mWh revenue figure. Mr. Hayet proposed a price of $43.2/mWh. Also, for ratemaking purposes (such as in the Wyoming PCAM), the Company normally imputes revenue to the SMUD provisional sales using a market price figure, while they are normally excluded from GRID. Using the unadjusted actual data and contract price for SMUD would increase NPC by $9.5 million in my GRID study.

Q. WHAT OTHER DIFFERENCES EXIST BETWEEN THE ACTUAL AND TEST YEAR RESULTS?

A. Gas prices have increased in the test year as compared to the historical period used by Mr. Duval. Reflecting the lower historical gas prices would result in a reduction to my GRID model results of $45 million. Also, the TransAlta contract was in place for the first three months of Mr. Duval's historical period. Including TransAlta for a comparable period in my GRID study would result in a $14 million reduction to NPC. Coal prices differed slightly between the two period, but not enough to result in a substantial change to NPC.

If all of these adjustments were made to my proposed GRID model result, the total NPC would be $1,094 million, an amount that is substantially higher than the test year result that I recommend.

Q. WHAT INFERENCE SHOULD THE COMMISSION DRAW FROM THIS COMPARISON OF ACTUAL TO GRID RESULTS?

A. First of all, I believe the Commission would want to apply the 2008 test year assumptions I used (discussed above) during the rate effective period. It is now too late to change the load forecast. While the Company was invited to update its test year when the Commission issued its test year order, Mr. Duval did not do so. To reflect higher loads now would require changes to power cost model inputs, billing units, revenues, and allocation factors.

Further, the other changes I used were built into the test year by the Company and reflect current conditions. Lake Side has come on line, gas prices are now higher, TransAlta is gone, hydro should return to normal levels, wind generation is increasing and so on. The 2008 test year is clearly more reflective of the rate effective period than the most recent 12 months of history. There is simply no comparison between the two. Mr. Duval's suggestion to the contrary is simply erroneous.

While Mr. Duval contends that I was unreasonable for recommending the $991 million figure, *the disparity with recent actual results stems largely from differences that had nothing to do with the adjustments I am recommending in the model.* Were I to conform my study to the major assumptions of the recent historical periods, my results would be much, much higher. Indeed, even higher than recent historical results. Load changes, provide by far the most significant difference between actual and GRID model results. I simply used the load forecast provided by the Company. If Mr. Duval has an argument with anyone, perhaps he should address it to the Company's load forecast group.

While I am not suggesting that the above represents a complete delineation of the differences between my GRID study, and Mr. Duval's actual results, it does illustrate that the two are hardly comparable in any fair sense. Given that this case has proceeded up until now, based on GRID model studies using on a 2008 test year, I recommend the Commission ignore Mr. Duval's attempted distraction and focus instead on the real issues of this case, *just as it did* *in the 2001 proceeding when Mr. Widmer presented a similar comparison to actual results in the rebuttal stage of the case.*

Q. EXPLAIN FURTHER WHY CHANGES IN LOAD SHOULD NOT BE CONSIDERED RELEVANT BY THE COMMISSION IN ITS EVALUATION OF NPC.

A. There is no other input to the ratemaking process that has a more profound effect on the final rates established than load inputs. The Commission had the opportunity to select a mid-2009 test year that contained higher loads than the 2008 test year, but it chose not to do so. Much of the difference between recent history and the GRID results is due to the load inputs. For this reason, I believe Mr. Duval's criticism of my study really amounts to a criticism of the Commission's test year decision. The use of a later test year would have increased NPC by roughly $41 million. Given that the Committee did not oppose the Company's original test year proposal, Mr. Duvall's criticism of my study appears misplaced.

Q. DO YOU HAVE ANY FURTHER COMMENTS CONCERNING EXHIBIT GND-2R-RR?

A. Yes. In this exhibit Mr. Duval attempts to show that the Company has historically undercollected power costs in Utah. However, his exhibit is flawed because he makes no effort to determine why the Company may have undercollected power costs in the past. Again, I believe that rapid sales growth was an important reason. A fair analysis of under collecting net power costs would also examine whether any variance was due to imprudent decisions or planning by the Company, or other factors such as the delay of the Lake Side plant.

Q. CAN YOU ELABORATE ON THIS PROBLEM?

A. Yes. Mr. Duval contends that the current NPC embedded in rates is $813 million. That figure is built into the 2007 and 2008 figures used in GND-2R-RR. The $813 million figure (based on sales projected for the 2006 rate case) assumed 21,538,272 mWh sales for Utah for the September 30, 2007 test year. The Company's current case assumes 22,619,224 mWh Utah sales for the December 31, 2008 test year, an increase of 5%. As sales have increased, so have revenues for recovery of net power costs. Reflecting the 5% sales increase increases the current NPC in rates from $813 to $854 million, *some $40 million more than claimed by Mr. Duval*. Further, it appears that actual sales for the 12 months ended March, 31, 2008 may have exceeded the Company's current test year forecast.[2] As a result, Mr. Duval's comparisons of actual to NPC in rates are wholly misleading and without value to the Commission.

Q. WHAT IS THE CONCLUSION YOU DRAW FROM THIS?

A. I urge the Commission to give no weight to the Company's arguments regarding actual costs and alleged prior under-collections. Instead, I urge the Commission to decide the NPC issues fairly, based on the merits of each adjustment.

<u>Workpapers and Support of CCS Adjustments</u>

Q. MR. DUVAL CRITICIZED YOUR RESPONSE TO THE COMPANY'S REQUEST FOR WORKPAPERS. PLEASE COMMENT.

A. Mr. Duval testifies on page 24 as follows:

> Despite a specific request for Mr. Falkenberg to produce organized, auditable work papers, the Company received a huge electronic file from him without any navigation instructions. Even though Mr. Falkenberg eventually produced a basic map to his work papers, the Company was still unable to analyze Mr. Falkenberg's adjustments in detail because of errors in his map and the difficulty

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[2] This was certainly the case at the system level.

of locating the relevant files in the work papers among the many files that had been created by Mr. Falkenberg that appear to have not been used to support any of his adjustments.

Q. IS THIS A FAIR COMMENT?

A. No. Mr. Duval left out some very pertinent facts. First, the Company did not file any data requests with the Committee to obtain my workpapers until April 21, 2008, two weeks after we filed our direct testimony. While the workpapers were essentially complete by the filing deadline, we had no way of knowing what specifically the Company might request. We received one minor data request from the Company a week after we filed our direct testimony asking for some backup information for a few of the Committee's adjustments. Responses were provided on time to the Company. The Company has not yet objected to those answers. On April 21, the Company filed a new data request specifically requesting my workpapers. The Company also requested that the Committee expedite the response. The response was expedited and by April 28th two CDs with the workpapers were provided to the Company. The next day, the full response was provided with basic "navigating instructions." Late in the day on May 1st (the actual response due date) the Company requested that additional detail concerning the "navigating instructions" be provided. I began working on the request immediately. At the same time, the Committee offered to let the Company talk to me to help sort out their difficulties. A more detailed set of navigating instructions was provided by email before the close of business on May 1, the original filing deadline for our response. By the following morning, the Committee provided the Company with the 1st Supplemental response to the

Company's request 5.1, which was essentially the same information as produced in the email, with a few minor revisions and corrections and provided more detailed text explaining the information provided to the Company previously.

Based on discussions after Mr. Duval filed his rebuttal, the Company's Manager of Net Power Costs appears to not have actually read the 1st Supplemental Response as of May 16, 2008. If true, this would certainly explain some of the difficulties in locating the specific GRID studies used to compute individual adjustments.

Mr. Duval's statement that I "eventually" provided a "basic map" to the workpapers leaves out the pertinent facts that the Company only filed its data request long after the testimony was filed and the Committee provided the bulk of the information three days earlier than requested by the Company. We also offered to provide more detail to the Company by telephone if they desired. The Company refused that offer.

Q. PLEASE COMMENT ON MR. DUVAL'S CONTENTION THAT THE COMPANY COULD NOT ANALYZE YOUR ADJUSTMENTS IN DETAIL DUE TO THESE PROBLEMS.

A. Having been on the other end of this type of issue many times over the years, I can certainly sympathize a little with Mr. Duval's situation. However, in this case, I think the problem stems from a lack of timely effort on the part of the Company. The Company did not request workpapers in a timely fashion. Nor did it read the all the pertinent information actually provided. Further, the Company did not avail itself of the opportunity to ask questions informally via email or by phone. I've worked with the Company for approximately ten years now. During that time, there was always a free exchange of information outside of formal discovery that worked both ways. In situations in which I did not receive adequate responses to discovery requests, I submitted follow up discovery requests seeking clarification of prior answers. In this case, I even scheduled on-site interviews. In contrast, in this case the Company made no effort to resolve any of its technical issues in this case by phone, email, face to face meeting, or follow up discovery prior to the filing of Mr. Duval's testimony. If the Company cannot understand the adjustments I proposed, it is due to a lack of effort on their part. Considering that Mr. Duval has now agreed in full or in part to more than half of the Committee's proposed adjustments, this seems to be little more than an excuse or another attempted distraction.

<u>CCS 4.1 through CCS 4.4 (GRID Commitment Logic)</u>

Q. DOES MR. DUVAL AGREE THAT THE GRID COMMITMENT LOGIC IS FLAWED AND SHOULD BE CORRECTED BY NIGHT-TIME SHUTDOWN SCREENS FOR THE COMBINED CYCLE PLANTS?

A. Yes, though his testimony seems needlessly argumentative, he ultimately agrees that GRID imprudently operates the system using its current logic. As such, he proposes a night time shut down screen for the combined cycle units until the GRID logic can be fixed. However, he provides no real justification for the screens he proposes, nor any support for their use. Nor were there any workpapers supporting these screens provided in any workpapers by the Company. My assumption is the Company developed these inputs by "trial and error" or based on the screens I provided in Exhibit CCS 4.6.

While I prefer the screens I developed, there is little difference between the two. Our screens differ only in that I would have the Currant Creek night time shut down screen start one hour earlier. Mr. Duval's proposed screen fails to remove $265 thousand of the uneconomic generation that I identified in the model. Mr. Duval simply proposes that the Company be allowed to keep the cost of this extra uneconomic generation. I disagree.

Q. DISCUSS MR. DUVAL'S PROPOSED SCREEN FOR WEST VALLEY.

A. Mr. Duval proposes a "light load hour screen" again with no support. This seems unnecessary, as there is already a night time shut down screen for these units, and it appears reasonable based on my studies. However, Mr. Duval would include many days during the test year when GRID uneconomically commits West Valley. This is questionable because the Company has agreed to remove uneconomic generation costs from peaking units in prior cases in Oregon and Wyoming. This was discussed in my direct testimony.

I continue to recommend the Commission require the Company to use screens developed using the methodology described in my direct testimony. The proposal I am making is superior to the Company's because it relies on an analysis of daily costs during the test period that specifically addresses those times when GRID is making incorrect decisions. While the impact of this change is not large, Mr. Duval simply provides no basis for his proposal. Furthermore, there is no justification to simply grant the Company the cost of uneconomic generation that the Company would like to build into the model.

Q. WHILE MR. DUVAL ACKNOWLEDGES THAT GRID IS IN ERROR, AND APPEARS TO ACCEPT MOST OF YOUR PROPOSED

ADJUSTMENT, IS HIS PROPOSED CORRECTION ACTUALLY INCLUDED IN THE COMPANY'S FINAL REBUTTAL NPC RESULT?

A. No. Mr. Duval ultimately recommends Alternative 1 on GND-1RR. This NPC result, 1,044 million is used in the Company's revised revenue requirement. That figure does not include this correction, despite the fact that Mr. Duval clearly acknowledges that GRID is wrong. Mr. Duval only <u>conditionally</u> accepts this and several other equally valid corrections, if certain other, unrelated, changes to the GRID inputs (such as a new forward price curve) are made. Mr. Duval's logic is startling to say the least. He is suggesting that errors in the model should only be corrected, if the Company is allowed to compensate by changing other unrelated items to reflect cost updates. Absent that, Mr. Duval recommends the Commission rely on costs he admits are based on incorrect input assumptions and dispatch logic. I urge the Commission to reject this proposal by the Company. I will discuss this matter as it pertains to other issues later in my testimony.

Q. IN YOUR DIRECT TESTIMONY YOU PROPOSED THAT THE COMPANY BE REQUIRED TO MODEL NON-FIRM TRANSMISSION IN ITS NEXT GENERAL RATE CASE, PARTLY AS A MEANS OF ADDRESSING THE PROBLEM OF UNECONOMIC GENERATION. MR. DUVAL DISAGREES. PLEASE COMMENT.

A. In late discovery I obtained some data related to non-firm transmission. As yet, I have not fully developed a satisfactory method for reflecting non-firm transmission in the test year. However, a few things are apparent already. First, the impact of non-firm transmission is not large, but it is significant enough (perhaps $5 million on a total Company basis) that it should be included in GRID. Second, non-firm transmission, by itself, is not a sufficient solution to the problem of uneconomic generator commitment in GRID. There will still be a need to solve the uneconomic generation problem in the future even if non-firm transmission is used.

I disagree with Mr. Duval's suggestion that non-firm transmission be ignored in the future. GRID should reflect an accurate forecast of prudent operation of the system. Non-firm transmission is used by the system in order to minimize costs. Just as it would be imprudent of the Company's real-time personnel to ignore non-firm transmission, it would be imprudent to ignore it in GRID, as well. Consequently, I continue to recommend the Commission require the Company to file non-firm transmission data for the four-year period as part of the MDRs in its next general rate case. This would not delay the filing, a concern expressed by Mr. Duval.

CCS 4.14 (Planned Outages)

Q. DOES MR. DUVAL ACKNOWLEDGE THAT THE COMPANY HAS ASSUMED AN UNREALISTIC PLANNED OUTAGE SCHEDULE?

A. Yes he does. Mr. Duval accepts the planned outage schedule of the DPU in Exhibit GND-1R-RR- Alternative 1, and offers another schedule in Alternative 2. It is unclear why he offers these two alternatives, but neither reflects proper normalization. I have already addressed the problems with the DPU schedule in my rebuttal testimony, so I won't restate all of those points here.[3] However, Mr. Duval made some additional arguments in favor of the two schedules he now proposes.

Q. WHAT ARE THE NEW ARGUMENTS MADE BY MR. DUVAL?

A. Starting at line 379, Mr. Duval testifies as follows:

Mr. Falkenberg's proposed outage schedule does not take into consideration all of the factors to be considered in outage planning. It is clear from page 54 of Mr. Falkenberg's testimony that the primary criteria he used was to align the maintenance schedule with the lowest market prices. As a result, his adjustment lowered net power costs by more than twice the level of Mr. Dalton.

Mr. Duval's statement that the "primary criteria" I used was to align the maintenance schedule with the lowest market prices is incorrect. The process I used was to align the schedule with actual practice, considering the amount of outage energy assigned to each month, the number of units on outage at a time, and the amount of capacity on outage. However, in regard to Mr. Duvall's comment that attempts to make it appear that I did something wrong by aligning the maintenance schedule with the lowest market prices, it turns out (based on our on-site interviews and results from using actual schedules in GRID) that the Company experts that actually schedule planned maintenance outages really do attempt to minimize system costs to the extent possible (contrary to Mr. Duval's assumptions.) This does entail "aligning the maintenance schedule with the market prices." In other words, one should try to schedule planned maintenance outages at a time that would result in the lowest costs to the system (which typically occurs when market prices are lowest), so long as all maintenance scheduling constraints are satisfied. I did just that.

Mr. Duval also contends the new outage schedule he has developed is based on taking into account all of the factors discussed in CCS data request 6.15. However, this is not much of a claim because, as I pointed out in my direct testimony, the criteria discussed in CCS 6.15 were already applied in GRID, and

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[3] Note that while the Company now concedes its planned outage schedule is incorrect, it maintained

represented a far cry from the scheduling considerations actually used by the Company.

Q. CAN YOU PROVIDE A COMPARISON OF THE COMPETING OUTAGE SCHEDULES IN THIS CASE?

A. Yes. Figure 1, below compares the various schedules.[4] As the figure shows, the Company moved outages out of January and February, but most ended up in March and April. Despite evidence of actual practice, the Company still proposes to schedule no planned outage energy in June and very little in May. Historically, May has the most planned outage energy. June is comparable to October, and normally far exceeds September. It appears from Mr. Duvall's schedule, that his primary criteria seems to have been to *avoid* scheduling maintenance in months that have low market prices, which completely ignores the actual history during the four-year period he used to establish the planned outage durations for each resource.

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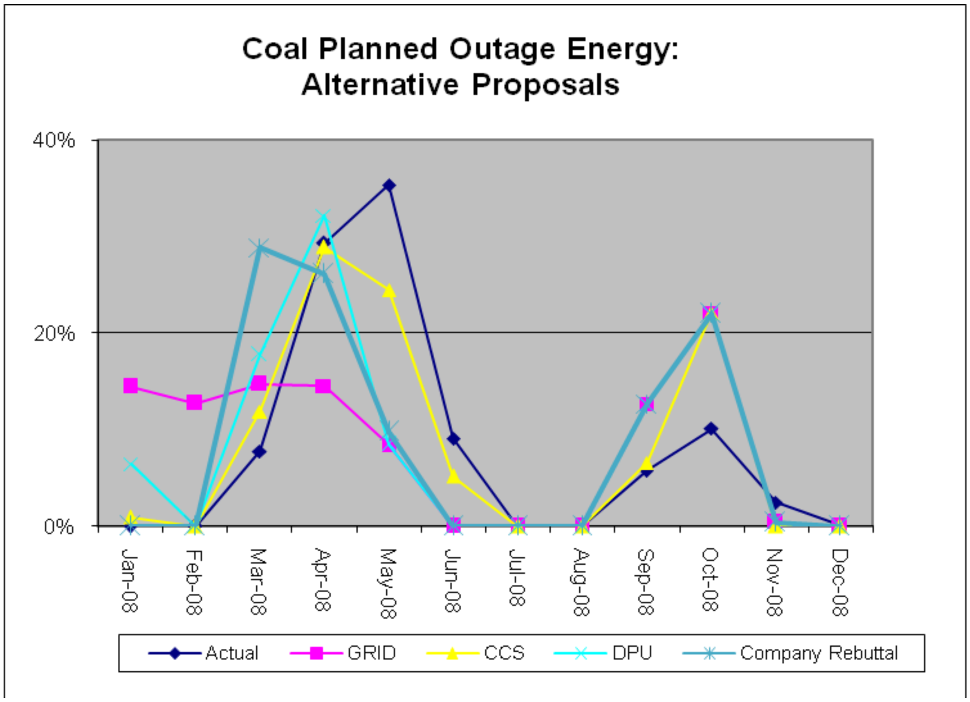
in its response to CCS 5.1, that the schedule used in GRID was proper.

[4] The line labeled "GRID" in the chart is based on the March filing for the test year.



Q. IS THERE A WAY TO RESOLVE THIS ISSUE?

A. I believe there is a very simple resolution to the matter. The Company bases its normalized outage energy requirements on the most recent four years of historical data (the 48 months ending June 2007) The simplest test of which outage schedule (the DPU's, the Company's or mine) is most reasonable is to compare the end results of each to the <u>actual schedules</u> used during the four-year period. To do this I analyzed four distinct outage schedules for the one-year periods starting September 1 for each year during the mid 2003 to mid 2007 period. By comparing the costs of actual outages over the four-year period to the cost of the various proposals made in this case we can determine which is most realistic. Exhibit CCS 4.1SR provides the actual schedules I used.

Q. ARE THERE OTHER ADVANTAGES TO THIS METHODOLOGY?

A. Yes. The use of the actual schedules is not subjective as compared to development of a schedule based on the GRID model criteria, or any other method. The data is readily available from MDR 2.57-2 and easy to apply and interpret. The number of outage days and outage energy is the same for the normalized schedules and the actual four-year average. As the four-year average underlies the Company's planned outage requirements, this is a logical extension of the Company's methodology, which has been accepted by the Commission for many years. Finally, because all four of these schedules were actually used by the Company, there is no basis to suggest they were "result oriented" (i.e. solely designed to align with low market prices") impractical, infeasible or otherwise improper.

Q. WERE THERE ANY UNITS FOR WHICH THIS APPROACH COULD NOT BE APPLIED DIRECTLY?

A. Currant Creek and Lake Side were not online for the entire four-year period. The Company used both prior and projected outages of these plants to determine the annual outage requirement (number of days). Because the Company also used and expects to use spring and fall outages for these plants, I used the Company's planned fall outage for one, and a spring outage for the other. I used the same schedule for all four years.

Q. PLEASE PRESENT THE RESULTS OF THIS ANALYSIS.

A. The table below presents these results. The figures shown are compared to the Company's original schedule, the DPU/Company Alternative 1 schedule (developed by Mr. Dalton) and the Company Alternative 2 schedule. The figures demonstrate that the composite result for the four years, $10.7 million is much closer to my proposed adjustment ($11.0 million) than any other schedule proposed in this case. It confirms the reasonableness of my proposed schedule.

However, I would certainly not object to simply substituting results from this analysis for the outage adjustment I have already proposed. (Use of four schedules might be less convenient for compliance filing purposes, however.)

Table 3

Schedule	Change M$	M mWh
2003-2004	-9.61	2.09
2004-2005	-26.13	1.57
2005-2006	-7.85	2.29
2006-2007	0.85	2.55
4 Yr. Average	-10.68	2.13
GRID Baseline	0.00	2.13
CCS 4.14	-11.00	
Company/DPU	-4.36	
Company Alt -2	-1.68	

Q. THE TOTAL NPC ADJUSTMENT FIGURES SHOW A WIDE COST VARIATION DURING THE FOUR-YEAR PERIOD. PLEASE EXPLAIN.

A. Outages are scheduled on a cyclical basis. The low cost year, (fall 2004 to summer 2005) was a period where relatively few planned outages were scheduled. The high cost period (2006-2007) coincides with a period where more than the average amount of outage energy was scheduled. This table actually provides a good reason for normalizing maintenance instead of using a single year. The results can vary substantially from one year to the next based on the actual outage schedule. This is why the Company uses a four-year average to develop the amount of planned outage energy to include in the test year.

Q. SHOULD THE COMMISSION VIEW THE COMPANY/DPU SCHEDULE AS A COMPROMISE BETWEEN YOUR PROPOSAL AND THE COMPANY'S OTHER PROPOSALS?

A. No. As shown above, the Company/DPU alternative produces a result that is much more costly than the planned outage schedules the Company actually uses. Indeed, it exceeds the cost of planned outage schedules for three of the past four years. Further, as pointed out previously, this schedule has a number of problems, and does not even remove all of the outage energy from the cold weather months. The Commission should keep in mind that the goal of maintenance scheduling is in fact to find the schedule that satisfies all scheduling constraints, but which results in the lowest Net Power Costs. The four actual schedules used clearly satisfy all scheduling constraints and produces much lower Net Power Costs. I strongly recommend the Commission reject the Company and DPU proposals.

CCS 4.22 (Heat Rate Modeling) CCS 4.23 (Minimum Loading Deration)

Q. DOES THE COMPANY AGREE WITH YOUR PROPOSED HEAT RATE MODELING AND MINIMUM LOADING DERATION ADJUSTMENTS?

A. No. Mr. Duval argues that the approach is wrong, because the Company has been using its deration approach in the same manner for the past 25 years, and no Commission has objected to it; that the exhibit supporting this technique is off base and poorly explained; and that the unit minimum capacity is an invariant quantity that should not be adjusted.

Q. PLEASE COMMENT ON MR. DUVAL'S FIRST POINT.

A. Since this is the first fully litigated Utah general rate case for net power cost issues since 2001, there is no specific Commission policy on this issue for the past several years. In 2001 and before, the Company used monthly energy cost models (in 2001 the "spreadsheet model" and prior to that, PD-Mac). In such models, minimum loadings are not modeled rigorously. Indeed, those models did not even require the minimum loading point as an input. Rather a "displacement limit" was used which set a floor on monthly generation. It is my recollection that the Company objected to even using minimum loadings and actual plant characteristics to develop these limits. The displacement limits were determined judgmentally by the Company. As a result, this may be the first fully litigated case in Utah in the past 25 years where the issue was even relevant.

Also, as pointed out in my direct testimony, GRID now shows many units running at minimum loadings, far in excess of actual operations. Thus, this problem is more important now and should be addressed.

Q. IS MR. DUVAL CORRECT IN SAYING THAT THE COMPANY HAS NEVER USED YOUR RECOMMENDED APPROACH IN ITS DERATION MODELING?

A. No. In fact, he's not even correct as regards the GRID model. GRID models a number of units for which the Company has partial ownership rights. The model uses an input called "PacifiCorp ownership percentage", which adjusts the heat rate to reflect partial ownership. For example, the Company owns 10% of the Colstrip units (76.5 mW out of 765 mW). The Company does not evaluate the heat rate curve of Colstrip 3 at 76.5 mW (10% of full loading - which would be less than the plant minimum) when it models the unit in GRID. Rather it adjusts the heat rate curve to appropriately reflect its share of the plant ownership. My proposal uses the same equation in making the deration adjustment. It simply does so for a different reason than the Company does.

Further, while Mr. Duval dismisses the concept of adjusting minimum capacities to reflect outages (as it does already for the maximum capacity) the

Company does exactly the same thing in preparing the minimum capacities for partially owned units. All that my proposal does is to treat the loss of capacity due to outages on the same basis as the Company already does for fractional ownership.

Q. EXPLAIN WHY THIS ADJUSTMENT IS NEEDED.

A. Assume hypothetically, that Currant Creek had an outage rate of 50%. This would mean the plant would only be available to run half the time. When it would run, it would likely run fully loaded – at its most efficient heat rate. However, based on the way GRID currently operates Currant Creek, it would be derated by 50%, and therefore, would run at half of its full load (an amount less than the minimum capacity of the plant). The Company's approach also would evaluate the heat rate at the 50% loading point, which is clearly wrong. At only half of full load, the unit would operate inefficiently. The Company's approach assumes that it derates the unit capacity by 50%, but leaves out the heat rate and minimum loading adjustments it makes in GRID for fractional ownership. It would show Currant Creek running at a loading level less than its actual minimum capacity, and at a high cost based on an inefficient heat rate.

In the recent Wyoming case, the Company's monthly outage rate data showed a very high outage rate for Gadsby Unit 1 for one month of the test year. This resulted in the unit being dispatched in GRID at only 570 kW, with a cost of nearly $1300/mWh. Exhibit CCS 4.2SR presents these results. While the Company might argue such circumstances aren't present in this case, that is only due to random chance. In order to avoid having to deal with such odd results occurring in future cases, the Commission should accept my adjustment.

Q. HOW DOES THIS APPROACH COMPARE TO INDUSTRY STANDARD TECHNIQUES?

A. As pointed out in Mr. Hayet's direct testimony which I have adopted, this approach is well accepted by the community of production cost modeling experts. Further, Portland General Electric ("PGE") uses an hourly deration model much like GRID, which makes the very same type of adjustments to heat rates and minimum loadings as I am proposing. Exhibit CCS 4.3SR provides copies of data request responses from PGE's current general rate case which confirms that it makes such adjustments to minimum loading and heat rates. I would note that the Oregon Public Utility Commission has accepted the PGE model for some time. Clearly, this is not an idea lacking in support throughout the industry.

Further, this methodology has been applied for quite some time in the industry. Around 1980 as an employee of a major A&E firm, EBASCO Services, I was responsible for development of a production cost model for use in developing PURPA avoided cost reporting requirements for many EBASCO clients. The model was used by many of the largest private and publicly owned utilities at the time, including Con Edison, Texas Utilities, San Antonio City Public Service Authority and Jacksonville Electric Authority to name just a few. While the model used a Monte Carlo simulation technique, it also could be run with the deration modeling option. I recently checked the code in the model, and it used the same type of deration adjustments I am proposing here. Clearly, this is not simply a novel new idea, but rather the right way to apply the deration model.

Q. DISCUSS MR. DUVAL'S CRITICISM OF THE EXPLANATION YOU PROVIDED FOR EXHIBIT CCS 4.16, WHICH SUPPORTED YOUR DERATION ADJUSTMENT IN YOUR DIRECT TESTIMONY.

A. Mr. Duval testifies on line 765 as follows:

> When asked to explain the content of this exhibit in a data request from the Company, Mr. Falkenberg responded by saying that "tracing through the calculations shown on this exhibit will enable the Company to understand this analysis."

Q. IS MR. DUVAL PROVIDING AN ACCURATE QUOTATION OF YOUR ANSWER?

A. No. My actual response to the data request is presented below:

> **CCS Response to RMP Data Request 5.25**
>
> See the answer to Question 5.9. Tracing through the calculations shown on this exhibit will enable the Company to understand this analysis. Essentially, the analysis shows that if the system had 2 units (Hunter and Gadsby) and each has the outage rate shown, there are 4 possible states for the system. (Hunter Up, Gadbsy Up, Hunter Down Gadsby Up, Hunter Up Gadsby Down, and Both Down). The model then calculates the production cost for each of the four states and shows that unless the deration adjustments proposed by Mr. Falkenberg are applied to the minimum loadings, and the heat rate equation, the deration model (as used in GRID) will incorrectly state net power costs.
>
> It is of some interest to note that the adjustment used for the heat rate curves is essentially the same as the Company models for the "PacifiCorp Ownership Percentage" variable as applied in GRID, and explain in the GRID algorithm guide.
>
> Finally, review of the MONET model used by Portland General Electric Company shows that they also use the same approach in modeling of derated capacity states as regards Mr. Falkenberg's proposed heat rate and minimum capacity state deration adjustments.

This answer provides more detail than Mr. Duval states above, and most certainly did not stop at telling the Company to *trace through the calculations*. It is also worth pointing out that the Company had this very exhibit and workpapers in its possession since January 2008, when I filed it in the Wyoming case. I never received a single question regarding the exhibit during that period of time. In addition, the Company did not ask any follow up data requests regarding any aspect of the exhibit, nor did it send any emails or make any telephone calls seeking clarification after our data response was filed until after Mr. Duval filed his rebuttal.

Q. MR. DUVAL SAYS EXHIBIT CCS 4.16 IS UNREALISTIC BECAUSE IT DOES NOT CONSIDER DERATIONS, ONLY FULL OUTAGES. WHAT IS YOUR RESPONSE?

A. Energy lost from full outages exceeds that due to partial outages by more than 60% for PacifiCorp generators. Full outages have a much more consequential impact on system costs than do partial outages. Further, even in the case of partial outages, the derated capacity used in GRID will not match the amount modeled by the Company, as derations can result from a wide variety of plant configurations. Therefore, cost will be misstated whether from full or partial outages. My proposal is a logical way to deal with this problem.

Q. DO YOU CONTINUE TO SUPPORT THIS ADJUSTMENT?

A. Yes.

<u>CCS 4.17 (Monthly Outage Rate Modeling)</u>

Q. DOES MR. DUVAL AGREE WITH YOUR PROPOSAL TO ELIMINATE MONTHLY OUTAGE RATE MODELING?

A**.** Yes, but only if the weekday, weekend differentiation of outage rates used in GRID is eliminated as well. Mr. Duval offers virtually no support for this proposal. He merely asserts that if a more general outage rate modeling is used, then there is no justification for retention of the weekday, weekend forced outage rate split.

Q. DO YOU AGREE?

A. Definitely not. There is no valid reason to model monthly outage rates, as Mr. Hayet and I both pointed out in our direct testimony. Mr. Duval apparently agrees because he did not even attempt to justify the monthly outage rate modeling currently in use.

However, the weekend, weekday forced outage rate split is much different. Unlike the monthly outage rate modeling, there are valid operational reasons why outage rates are higher on weekends than on weekdays. There is a definite pattern in weekend and weekday outage rates, rather than just random variations that occur with monthly outages. Finally, weekend and weekday outage rates can be computed based on a full 48 months of data rather than using small samples of data limited to only four observations per unit for each of the 12 months.

Q. EXPLAIN WHY OUTAGE RATES ARE HIGHER ON WEEKENDS THAN ON WEEKDAYS.

A. Certain types of outages, called maintenance outages can be deferred to avoid taking units offline during high cost periods. The NERC definition of a maintenance outage is an event than can be deferred until beyond the next weekend, but not beyond the next planned outage. These types of outages have flexible start dates, and the lost energy associated with them occurs more frequently in the weekend and other off-peak periods.[5] In order to minimize costs, utilities do schedule maintenance outages at lower cost periods such as during the weekend when possible. Maintenance outages and other deferrable events make up 15% of all energy lost by PacifiCorp generators. As a result, more than 90% of the Company's thermal resources have higher weekend than weekday outage rates. The weekend outage rates average 22% higher than the weekday outage rates for the Company resources. A comparison of weekend and weekday outage rates is shown on Exhibit No. CCS 4.4SR.

There are therefore two justifications for not discarding the weekend-weekday outage rate split. First, it reflects the actual cost minimizing practices of the Company. Second, there is a sound analytical basis for its use. This contrasts with the monthly outage rate approach which has no basis in actual practice and no analytic support. As a result, I recommend the Commission reject Mr. Duval's proposal.

Q. IS MODELING OF WEEKEND AND WEEKDAY OUTAGE RATES STANDARD INDUSTRY PRACTICE?

A. Yes, and it has been so for some time. Since the mid 1970s, PROMOD (a model in use by more than 100 utilities) had provisions for a weekend, or off-peak maintenance outage rate. Mr. Hayet still works with PROMOD on a regular basis and informs me that provision still is present in PROMOD and that it is commonly used. As he pointed out in his direct testimony, it is most certainly uncommon for utilities to use monthly or even seasonal outage rates. In the end,

[5] Until 2005 the Company modeled all maintenance outages during the weekend period. Subsequently, it changed to the current method. While I believe the prior treatment is more

Mr. Duval's proposal lacks merit. The current methodology, using a different weekend and weekday outage rate has been used by the Company in all of its major rates cases since GRID was introduced. Until now, I am not aware of the Company ever suggesting this should be discarded.

<u>CCS 4.19 (Ramping)</u>

Q. DOES MR. DUVAL AGREE WITH YOUR PROPOSAL TO REVERSE THE COMPANY'S RAMPING ADJUSTMENT?

A. Mr. Duval continues to support the Company's inclusion of ramping in outage rates, but does concede that for gas units, at least, the methodology may *inadvertently cover a gas plant being held for reserve.* (Line 458). He also contends that while the Washington Commission rejected the ramping adjustment, it focused on the calculation method for outage rates not on the concept. (Lines 448-450.) Mr. Duval proposes a smaller ramping adjustment ($1.7 million) than the $4 million I proposed.

Q. DO YOU AGREE WITH HIS ALTERNATIVE PROPOSAL?

A. No. First, while the analysis of ramping presented in Exhibit CCS 4.15 examined only one of the Gadsby units, it should not be inferred that this problem applies *only* to gas units. Many of the problems that resulted in an obvious overstatement of ramping lost energy would apply to any type of unit. Many of the Company's thermal units are required to supply reserves from time to time, and/or experience deration events that would be counted as ramping in the Company's flawed methodology. This can be seen by looking at other data available in this proceeding.

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appropriate, I will not press the issue in this case, but request the Commission keep an open mind

Q. PLEASE ELABORATE.

A. A more accurate approach to determining the ramping loss adjustment would be to use the actual ramp rate for the unit. In the response to CCS 2.38 Confidential, it is shown that the ramp rate for Gadsby 1 is X per minute. This would imply the unit could reach 90% of full load in X minutes. For a single start, this would result in total ramping losses of about XX XXX. Referring back to Exhibit CCS 4.15, for the two starts that occurred in March 2007, this would result in a total loss of generation no more than XX XXX as compared to 994 mWh in the Company's method. However, in both cases, some of the unit's capacity was assigned to reserves, so the actual loss would be less, as the units would not have needed to be ramped up to full capacity. Further, there is no reason to assume the unit would have been dispatched to full load. Because it takes XXXXXXXXX for the unit to ramp up to full load, and the subsequent hours were dispatched to less than full loading, the Company's methodology most certainly overstates energy lost due to ramping.

Q. CAN YOU DEMONSTRATE THAT THE COMPANY'S RAMPING ADJUSTMENT IS OVERSTATED FOR ALL PACIFICORP UNITS BASED ON THE ACTUAL RAMP RATES REPORTED IN CCS 2.38?

A. Yes. Exhibit No CCS 4.5SR shows a computation of the total amount of energy lost due to ramping based on the number of starts in the four year period and actual unit ramp rates. It shows that at the very most, the lost energy due to ramping amounts to 23% of the amount the Company includes in GRID.

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on the matter for future proceedings.

Even the 23% figure overstates ramping losses because it ignores the fact that units often run below full load due to load conditions, reserve allocations, or due to partial outages. Further, as shown in Exhibit CCS 4.15, the Company assumes ramping losses can occur many hours after a unit is started and running near full load, and the Company assumes that when a unit starts to shut down, even more energy is lost to ramping.

In the end, there is little basis for the outage rate adjustment for ramping proposed by the Company. The Commission could reject the Company's entire ramping proposal. However, purely as a compromise for this case, I have recomputed my ramping adjustment allowing the maximum possible ramping energy based on the actual thermal unit ramp rates. Exhibit CCS 4.5SR shows the maximum ramping energy for each plant. I have reflected this additional ramping in CCS Adjustment 4.19SR.

My revised ramping adjustment also makes a minor correction to the computation of outage rates. In my computation of the annual outage rates I simply averaged the twelve monthly weekend and weekday outage rates. However, this assumes all months have the same number of days, and doesn't give the most accurate weighting. A more accurate calculation would compute the annual weekend and weekday rates based on annual ratio of lost to scheduled energy. This is the way in which the Company computed its annual average outage rate in preparing its rebuttal. I included this adjustment in my computation of the revised outage rates used in CCS 4.19SR. Overall, my revised outage rate calculation methodology results in an increase to NPC (as compared to my direct testimony) of approximately $1.5 million total Company.

Other Updates, Corrections and New Costs

Q. DO YOU HAVE ANY CORRECTIONS YOU WISH TO MAKE AT THIS TIME?

A. Yes. I discovered that there was an error in Table 1 in my direct testimony in that it did not contain the correct figure for Call Option Adjustment, CCS 4.5. The figure shown simply did not match the figure supported in my exhibit, a purely typographical error. Correcting it results in an increase to total Company NPC of $1.1 million. There was also a minor ($400) error in Exhibit CCS 4.5, which I also corrected.

Q. HAS MR. DUVAL ACCEPTED ANY OTHER ADJUSTMENTS AS CORRECTIONS TO THE FILING?

A. Mr. Duval accepts the corrections proposed for the Currant Creek outage rates (CCS 4.21), SMUD Leap Year Adjustment (CCS 4.8) and Self Supply Non-owned Reserves (CCS 4.26). As discussed above, Mr. Duval also acknowledges the dispatch logic in GRID is wrong, and believes a net adjustment in excess of $9 million should be made. However, he proposes to make this correction on a conditional basis only.

Q. DID MR. DUVAL FULLY IMPLEMENT THE FIRST THREE ADJUSTMENTS?

A. No. The Currant Creek outage rate adjustment contained two parts – a forced outage rate adjustment and a planned outage rate adjustment. He only accepted the former adjustment. The latter adjustment reduced the Currant Creek planned outage duration for the test year from 9 to 8 days. Though this is an inconsequential adjustment under my proposed outage schedule, it could be more significant under the Company's proposed outage schedule. It should be accepted in either case.

Also, it appears that Mr. Duval did not accept all of the Self-Supply non-owned reserves adjustment. This again had two parts, both an eastern and a western control area component. It appears that Mr. Duval accepted only the eastern control area component of the adjustment. In recent discovery in the Washington case, the Company acknowledged that it overstated reserve requirements for the western control area as well. (See Exhibit No. CCS 4.6SR. Note that the Washington case used the same GRID inputs for this item as in this case.) However, at this point, it appears that I also overstated the western control area portion of the adjustment because I removed more than these two contracts. Removing only the two contracts that the Company agrees self supply reserves results in an additional increase to Mr. Duval's computation of the CCS 4.26 adjustment by about $200 thousand and reduces my proposed adjustment. My corrected adjustment for this issue is shown on Table 1 Surrebuttal.

Finally, as discussed above, Mr. Duval did not implement the GRID logic correction in his recommended NPC result of $1,044 million.

Q. DID MR. DUVAL PROPOSE ANY OTHER CORRECTIONS TO THE FILING?

A. Yes. Mr. Duval proposes to include electricity swaps and indexed gas transactions amounting to $3.2 million. These were left out by mistake according to Mr. Duval.

Q. DO YOU AGREE WITH THE INCLUSION OF THESE KINDS OF COSTS?

A. No. It includes new kinds of costs, making it more of an update than a correction. It troubles me that the Company has first informed parties of this substantial error at this late date and in such an indirect manner. I am also concerned that this could be considered as establishing precedent. By introducing new kinds of costs at this time, the Company effectively limits the parties' opportunity to inquire as to the prudence of the costs and the most appropriate ratemaking treatment.

Q. ARE THERE OTHER ASPECTS TO THIS PROBLEM?

A. In its decision concerning the test year, the Commission invited the Company to update its filing when it prepared the new test year. The Company made no corrections or updates to GRID at that time, though it did make at least one other correction at that time.

Q. HAS MR. DUVAL ACCEPTED ANY OTHER ADJUSTMENTS?

A. Yes. Mr. Duval has <u>conditionally</u> accepted the following adjustments: CCS 4.6 (Hermiston Losses); CCS 4.10 (Biomass Non Gen); CCS 4.11, DPU 6.1 and UAE 1.6 (Sunnyside QF); CCS 4.12 (Schwendiman Contract Deferral); CCS 4.27 (Goodnoe Transmission); CCS 4.28 (Borah Brady Transmission); CCS 4.29 (Transmission Cost Escalation) and DPU 6.3 (Tesoro and Kennecott PPAs). While I am glad that the Company has recognized the validity of these adjustments, I disagree with his characterization of these as "updates" or "new information." These adjustments do not rest on new information at all.

The Hermiston Loss adjustment was based on a letter the Company received in early 2005. The Company instituted its Hermiston loss adjustment in

GRID around that time. This clearly does not represent “new information”, but rather proper application of information long available to the Company.

The Sunnyside QF contract negotiation was completed in 2007. The Company actually used an estimated price revision for its actual power cost reports in 2007 as well. Had the Company estimated the final impact of the new contract in its direct case, then updated it with final numbers it would be fair to characterize this as an update. Instead, it amounts to a correction.

The Borah Brady Transmission Pro-Forma, Goodnoe Transmission Pro-Forma and Transmission Cost escalation adjustments are not based on new information either. While the Borah Brady adjustment was based on recent data, it was necessary to correct information used in the filing for which the Company could not provide any support. The Company could have used supportable information in the first place. My Transmission Cost escalation adjustment was based on data available to the Company as of November 2007, prior to the filing. The corrected Goodnoe cost data was filed by the Company in Washington in February, 2007, well in advance of the time it filed its 2008 test year.

Likewise, the Biomass non-generation agreement adjustment was premised on the fact that the Company had entered into such agreements for the previous three years. This was well known to the Company when its case was filed. Finally, the Schwendiman contract adjustment was based on the Third Amended contract dated October 2007, again, in advance of the filing date.

Q. WHY IS IT IMPORTANT TO CHARACTERIZE THESE ADJUSTMENTS AS CORRECTIONS RATHER THAN UPDATES?

A. Mr. Duval has attempted to blur the line between our legitimate “corrections” and his illegitimate “update.” If the Commission were to decide against allowing updates (such as Mr. Duval’s proposed forward curve adjustment) it should not eliminate these legitimate corrections at the same time.

Q. IS THERE ANY REASON THE COMMISSION SHOULD BE CAUTIOUS OF UPDATES LATE IN A CASE?

A. Certainly. Mr. Duval has already expressed the Company’s sentiment that Utah regulation has systematically resulted in the Company under-recovering its costs. Presentation of an 11th hour “update” of this sort raises the concern that updates for cost reducing items were overlooked.

Q. DO YOU OPPOSE MR. DUVAL’S FORWARD CURVE UPDATE?

A. Yes. In the case at hand, it is clear that the Company ignored inputs that would reduce its cost. Mr. Duval proposes to update only the forward cost curve, but did not reflect changes to hydro shaping that accompany the new forward curves. The Company refused to provide the revised GRID inputs resulting from reshaping when we specifically asked for them in a data request. The Company did make such hydro shaping adjustments in other cases when it revised the forward price curve. I estimate this item alone would result in a reduction to NPC of $500 thousand on a total Company basis based on results in recent cases.

Q. MR. DUVAL SUGGESTS YOU WOULD NOT OBJECT TO THE FORWARD CURVE UPDATE BECAUSE IT IS USED IN OREGON AND IS A MINOR CHANGE. PLEASE COMMENT.

A. In Oregon, specific types of updates are allowed on a specific schedule. Updates in Oregon are not optional at the Company’s discretion, as Mr. Duval seems to prefer in this case. Further, in prior Oregon cases, when updates were prepared the Company provided a separate GRID run for each new contract or major input category so that parties could evaluate the changes. In this case, the Company has not even provided the actual value of its forward curve adjustment, but instead coupled it with other adjustments. Further, the Oregon process allows for parties to challenge adjustments made by requesting a new procedural schedule. This was done in a PGE case in late 2004, when a call option contract was first introduced.

The Commission already gave the Company the opportunity to update its case when it produced the 2008 test year. The Company should not be allowed "another bite at the apple" simply because its NPC study has so many flaws and is demonstrably overstated. Mr. Duval's proposed update is little more than a request for a "do-over."

Finally, as regards the suggestion that the forward price curve change is a minor matter, this is most certainly not the case. I estimate that the forward curve adjustment amounts to more than a $10 million increase to NPC. However, the actual components of this change are far more significant. Mr. Duval changes the gas swaps line in GRID by $66 million but this is more than offset by other changes in gas prices, electric prices and certain contract prices of more than $76 million. Clearly, the forward curve update is a major change in the model.

CCS 4.5 (Call Options) and CCS 4.13 (STF Arbitrage and Trading)

Q. MR. DUVAL OPPOSES YOUR CALL OPTION ADJUSTMENT ON THE BASIS THAT IT IS UNIQUE TO THE OREGON REGULATORY MODEL AND NOT APPLICABLE TO UTAH. PLEASE COMMENT.

A. The issue of call options is one I have raised in earlier settled cases and there is no Commission precedent on this matter in Utah. If nothing else, it would help for the Commission to rule on this matter. In my direct testimony, I already addressed the argument that the Oregon procedure (proposed by the Company) should not be applicable in Utah, so I won't repeat it here.

Q. MR. DUVAL EXPRESSES CONFUSION SURROUNDING THE CALL OPTION ADJUSTMENT OF $3.59 MILLION. HE ALSO SUGGESTS THAT THE COMPANY COULD NOT UNDERSTAND YOUR ANALYSIS OR WORKPAPERS. PLEASE COMMENT.

A. I accept responsibility for the mistake related to the incorrect value for the call option adjustment appearing on Table 1 as well as any confusion it created. However, the figure $3.59 million was supported in Confidential Exhibit CCS4.7 and detailed workpapers were provided to the Company.

As I pointed out earlier, this concept is one that the Company has already proposed in Oregon so they should have had little trouble understanding the matter. To ensure, however, that the Commission understands this adjustment, I present Confidential Exhibit CCS 4.7SR which provides a calculation of the disallowances related to the NEBO contract. I believe review of this work will establish that the concept is not difficult to understand, and in fact, is quite similar to the approach used to determine uneconomic generation on a daily basis for West Valley. I already presented that analysis as Exhibit CCS 4.5 in my direct testimony.

Q. MR. DUVAL AGREES THAT CALL OPTION CONTRACTS SHOULD NOT BE DISPATCHED UNECONOMICALLY IN GRID. HOWEVER, HE SUGGESTS THAT THE PROBLEM IS INCONSEQUENTIAL. PLEASE COMMENT.

A. It appears that Mr. Duval has not analyzed this problem on a daily or even monthly basis. Based on a run using his new forward price curve (Line 4 on Alternative 2 of GND-1R-RR) without NEBO, there is $635 thousand in uneconomic generation costs for that contract in March 2008 alone. This is nearly 70% of the $922 thousand adjustment I estimated in my direct testimony. Mr. Duval has not cured the uneconomic generation problem by changing the forward price curve. As a result, I continue to support this adjustment irrespective of any change to the forward price curve.[6]

Q. DO YOU AGREE WITH MR. DUVAL'S CRITICISM OF THE SHORT TERM FIRM ARBITRAGE AND TRADING PROFITS ISSUE?

A. His arguments on this matter parallel those of the call option issue. In this case, however, I agree to withdraw the adjustment because it quite specific to the Oregon TAM process and the Company has never agreed to its use. Oregon uses a fully projected test year (the current Oregon NPC case uses a December 31, 2009 test year.) This allows less opportunity to capture the actual benefits of the STF transactions in the test year, as most arbitrage and trading opportunities seem to arise closer in time to actual trade dates. Use of an earlier test year tends to undermine the Oregon justification for this adjustment.

<u>CCS 4.7 and CCS 4.9 (SMUD)</u>

Q. MR. DUVAL TESTIFIES THAT NO CHANGE IN THE SMUD IMPUTED PRICE SHOULD BE MADE. PLEASE COMMENT.

A. Mr. Hayet supports an imputed price of $43.8/mWh for SMUD. As Mr. Hayet pointed out, the cost of serving SMUD is $76/mWh, far less than his

[6] Should the new forward curve be adopted, the adjustment should be recomputed.

recommended contract price. I believe this demonstrates the reasonableness of the Committees' SMUD adjustments and we continue to support them for the reasons provided in our direct testimony.

Q. PLEASE COMMENT ON MR. DUVAL'S CONTENTION THAT IF SMUD IS REPRICED, THEN SO SHOULD THE MID-C CONTRACT.

A. This is a specious argument. The Commission has already recognized that the history of the SMUD contract differs from that of other contracts, such as Mid C. SMUD is the only contract for which the Commission has a long history of price imputation because the reasonableness of this contract is in question. The Company did not get to keep a $98 million up front payment for any other below market contract it now has in place. The Commission should reject this argument.

Q. WHY DOES MR. DUVAL OPPOSE THE SMUD CONTRACT NORMALIZATION ADJUSTMENT?

A. Mr. Duval asserts that it is not a proper normalization, but provides no explanation or support. He also contends this adjustment is "one-sided" and "selective." I disagree on both points.

First, the concept of normalization is to use actual data where applicable, but to smooth out year to year variations. I did this with SMUD, using a four-year average monthly energy distribution. The Company uses four-year averages for many inputs to GRID. There is nothing improper about this normalization technique.

Second, Mr. Duval suggests it is one sided to apply this adjustment only to SMUD, and that I should have looked at other contracts. The Company has more than 70 contract line items in GRID. Some of these line items represent a combination of many smaller contracts. It is an unreasonable standard to suggest that one contract cannot be corrected, unless all contracts are corrected. The Company did not insist upon this standard when it agreed to the adjustments to the various other contracts proposed by Mr. Dalton, or Mr. Hayet, or even the SMUD Leap Year adjustment.

Q. MR. DUVAL TESTIFIES YOU ARE PROPOSING TO "DE-OPTIMIZE" SMUD WHILE SEEKING TO OPTIMIZE SYSTEM DISPATCH. IS THIS A REASONABLE CRITICSM?

A. No. The Company controls the operation of its system and attempts to minimize cost. SMUD does the same for its system. Mr. Duval has already acknowledged that GRID is in error in the way it seeks to utilize certain resources but that fact has no relationship to SMUD. The energy demanded by SMUD is not controlled by the Company, but rather by the counterparty. Mr. Duval seeks to model the "worst case scenario" in the way that the contract *could* be used by the counterparty. As I pointed out in my direct, one must assume the SMUD contract is optimized by the counterparty subject to the constraints they face. However, their circumstances differ from those of the Company. The Company's modeling completely ignores whatever real world factors drive SMUD to make different choices concerning how the contract is used. SMUD's objective is to minimize its own costs, not to inflict the maximum cost on PacifiCorp. Mr. Duval simply refuses to acknowledge this fact.

Finally, the Commission should recognize that when the SMUD contract price imputation was last decided, the Company did not model SMUD as a call option sale. Rather the Company used an energy distribution that showed sales taking place in both low and high cost months. The Commission has never ruled on whether SMUD should be modeled as a call option sale or not, but its last real decision used a much different approach. This point (made in my direct testimony and illustrated in Table 2) has not been addressed by Mr. Duval.

<u>CCS 4.15 (Hydro Modeling) and CCS 4.16 (Hydro Reserve Input Parameter)</u>

Q. PLEASE COMMENT ON MR. DUVAL'S TESTIMONY CONCERNING THE CCS 4.15 ADJUSTMENT.

A. What is clear from his testimony is that Mr. Duval opposes any hydro adjustment. Unfortunately, Mr. Duval's testimony is contradictory and inaccurate. It would appear that Mr. Duval did not understand my proposal. For example, Mr. Duval testifies at lines 636-641 as follows:

> Mr. Falkenberg alleges that the Company's VISTA model for modeling normalized hydro generation overstates the likelihood of extreme hydro conditions. He recommends that the Commission eliminate this alleged bias by changing the weights for the Wet, Median and Dry cases to those he developed based upon historical data. This adjustment lowers modeled NPC $3.5 million on a total company basis.

While the above characterization of my testimony is accurate, Mr. Duval states on line 655 "Mr. Falkenberg argues for exclusive use of the median, or 50 percent exceedance level." This is not only inaccurate it also contradicts the first passage quoted above. My proposal was to use proper weights applied to the Wet, Median and Dry scenarios.[7]

Q. MR. DUVAL DISPUTES YOUR CONTENTION THAT THE COMPANY'S WET AND DRY CASES OVERSTATE THE LIKELIHOOD OF EXTREME EVENTS. PLEASE COMMENT.

[7] I did suggest the use of the Median case, but only as the minimum necessary correction to the power cost study.

A. Mr. Duval provides little support for this assertion and never addressed the analysis I performed proving this point. My direct testimony showed that the Wet and Dry cases that Mr. Duval assumes represent the 25, and 75 percent cases, really represent the 1 percent and 98 percent cases. (See Exhibit CCS 4.11).

Q. ON WHAT BASIS DOES MR. DUVAL DISPUTE THIS ADJUSTMENT?

A. Mr. Duval makes three arguments. He asserts, without any support, that the Company's method "fairly approximates" the Wet, Dry and Normal cases (line 679); that the Oregon Commission rejected a much different proposal I made last year; that there is "some correlation" between river systems (line 665, again with no support); and that it probably doesn't matter anyway (line 681, again without support).

Q. HOW DO YOU RESPOND TO THESE ASSERTIONS?

A. It is rather difficult to respond meaningfully to unsupported assertions or to irrelevant issues such as the recent Oregon order which addressed a different adjustment than I am proposing in this case. His point that "some correlation" exists between river systems can be tested, however. The table below shows the actual correlation for annual energy generation from 1964 to 2003 for the five major river systems from which the Company obtains hydro energy. The analysis shows moderately strong correlation between the Umpqua and Klamath rivers (p=.81), but only moderate to very weak correlation for the rest. While Mr. Duval might be satisfied that this demonstrates "some correlation" exists, the Company's method assumes *nothing less than perfect correlation.* This is why the

Company's method so substantially overstates the severity of the wet and dry cases, as shown in CCS 4.11.

Table 4 Hydro Correlation – Major River Systems: 1964-2003

	Umpqua	Klamath	Lewis	Mid C	Bear
Umpqua	1.00	0.81	0.47	0.34	0.63
Klamath		1.00	0.63	0.32	0.50
Lewis			1.00	0.13	0.11
Mid C				1.00	0.39
Bear					1.00

Q. DO YOU CONTINUE TO SUPPORT YOUR ORIGINAL ADJUSTMENT?

A. While I continue to believe this is a reasonable adjustment, I would be satisfied if the Commission required the Company to file a conventional forty water year modeling study as one of the MDRs in its next general rate case, similar to that required in Washington. The availability of a forty water year study applicable to the test year would enable the Commission to determine whether the Company's approach is biased or not. This is a proven technique and would resolve this entire controversy. The Company is already required to produce this data for one other jurisdiction.

Q. DO YOU ACCEPT MR. DUVAL'S ARGUMENTS CONCERNING THE HYDRO RESERVE INPUT PARAMETER?

A. Mr. Duval provides no analytical support for the assertions he makes concerning this input. However, as I pointed out in my direct testimony, this issue was not included in the Committee's total NPC adjustment. I believe the issue warrants further study before any adjustment is made. Mr. Duval has certainly provided nothing to suggest the Commission should not investigate this matter in future cases.

<u>CCS 4.20 (Duct Firing Reserve Capability)</u>

Q. DO YOU ACCEPT MR. DUVAL'S ARGUMENTS CONCERNING THE MODELING OF DUCT FIRING?

A. Mr. Duval is incorrect in his assertion that the heat rate curve used in GRID cannot model the jump to a higher heat rate curve when duct firing is started. In fact, the heat rate equation used in GRID is based on operation of the plant in both its conventional and duct firing mode of operation. (This is very clear from the Confidential Response to CCS 7.5.) However, as I pointed out in my direct testimony, this issue was not included in the Committee's total NPC adjustment. I continue to recommend the Commission require the Company to address this problem in its next general rate case.

<u>CCS 4.24 (Station Service)</u>

Q. DOES MR. DUVAL OPPOSE THIS ADJUSTMENT?

A. Yes. He asserts that *"Unless a separate load adjustment is made as proposed by the Company, the costs of that station service will not be recovered by the Company and there will not be a proper match between costs and benefits"* (lines 805-808). He provides no logical support for the assertion that a load adjustment, rather than a heat rate adjustment in required. This is the same treatment applied to more than 99% of station service requirements in the development of GRID heat rate inputs. His main argument for treating this very small component of station service differently from the rest is that *"Load is equal to net generation plus interchange. Net generation only captures station service when the units are* *running, thereby excluding station service when the units are not running.*" (lines 801-803.) In other words, it is not because the nature of the station service load differs when units are not running just that it has not been counted properly in the net load calculation. Therefore there is no reason to treat this component of station service any different from the rest – it should be reflected as an increase to generator heat rates, rather than as an incremental load.

Q. WHAT IS YOUR RECOMMENDATION?

A. This issue comes down to <u>how</u> station non-running service costs should be computed in GRID. I don't find Mr. Duval's arguments persuasive, but now believe it may be worthwhile to try to reconcile the differences between the two approaches before making a change to the current modeling.

<u>CCS 4.18 (Bridger Error Outages)</u>

Q. DOES THE COMPANY OPPOSE THIS ADJUSTMENT?

A. Yes. The Company presents the testimony of Mr. Mark Mansfield, Vice President of Thermal Operations Support. Mr. Mansfield makes a number of arguments, but never addressed the reasonableness of the specific outages for which I recommend disallowances (identified in Confidential Exhibit CCS 4.14.) As a result, the prudence of these specific outages has not been justified by the Company. As prudence was the foundation of my proposed adjustment, I will only provide a limited response to Mr. Mansfield's otherwise unresponsive arguments.

Q. MR. MANSFIELD MAKES MUCH OF THE FACT THAT THE CAPACITY FACTOR FOR PACIFICORP PLANTS EXCEED THE NERC AVERAGES. PLEASE COMMENT.

A. This is an irrelevant comparison. PacifiCorp has load that exceeds coal-fired generation most hours of the year, and market prices in the region exceed coal dispatch costs throughout the year. This is not always the case in other regions of the country. In many parts of the country, coal is at the margin many hours of the year. As a result, coal capacity factors for PacifiCorp exceed those of other regions. This has little to do with anything PacifiCorp is responsible for. It would be like saying my car is more reliable than Mr. Hayet's because I drive 20 mile a day to work, while he only drives 10.

Q. PLEASE COMMENT ON MR. MANSFIELD'S TESTIMONY CONCERNING THE EQUIVALENT AVAILABILITY FACTOR AND THE PLANNED OUTAGE FACTOR.

A. Given the demonstrated increase in unplanned outages, Mr. Mansfield seems to be admitting that the Company has reduced planned outages at the expense of unplanned outages. This is a questionable strategy because planned outages can be scheduled at low cost times, while unplanned outages can happen at any time. An unplanned outage can cost many times more than a planned one. Should the Company experience system wide outages during summer or winter peaks in the months ahead, this strategy may be to blame.

Finally, Mr. Mansfield certainly lends credence to the testimony of IBEW witness, Mr. Gary Cox, who believes the Company has undertaken this questionable strategy as a cost-cutting measure. I question the prudence of Mr. Mansfield's strategy and recommend the Commission do so as well.

Q. MR. MANSFIELD ARGUES IT IS ONE-SIDED TO PENALIZE THE COMPANY FOR THE POOR PERFORMANCE OF BRIDGER, WHILE IGNORING OTHER PLANTS. PLEASE COMMENT.

A. The prudence standard applies to all plants not just Bridger. One does not get a reward for being prudent, but there has always been a penalty for imprudence. I presented direct evidence from the Company's own RCA reports that call into question the prudence of specific outages at Bridger. The Company has not justified the prudence of any of these events.

Q. WHAT IS YOUR RECOMMENDATION?

A. Based on the testimony of Mr. Cox and Mr. Mansfield, I believe that by far the most significant issue in this case is the question of the Company's overall maintenance practices and strategy. I seriously question whether reducing planned outages is a reasonable trade-off for increased forced outages.

I would have liked to have analyzed the costs of reduced planned outages versus increase forced outages in this case. However, time is too short for that now. Consequently, I believe this issue should be investigated much more fully before proceeding with an outage rate adjustment. Rather, I recommend that the Company be required to justify the economics of its scheduled maintenance strategy and practices in its next general rate case.

CCS 4.25 (Wind Integration Charges)

Q. MR. TALLMAN DISPUTES YOUR WIND INTEGRATION ADJUSTMENT. PLEASE COMMENT.

A. Mr. Tallman contends it was not proper to apply the IRP Appendix J methodology to the test year level of installed wind capacity; that it was incorrect to use GRID to compute the cost of wind integration; that the Company left some of the wind resources out of its calculation; and that BPA has now instituted a new wind integration charge.

His first point is that the wind integration charge developed in the IRP was not intended to be parsed out into individual components of the wind portfolio. This is irrelevant, however, because I used a wind reserve requirement consistent with the chart on page 192 of Appendix J to the IRP that relates installed capacity to the incremental reserve requirement. It is now an accepted fact that as installed wind capacity increases, the average cost of wind integration increases as well. Mr. Tallman is suggesting that if the Company stopped adding new wind resources, the reserve requirement for the current 1200 mW would be the same as for the originally planned 2000 mW. Contrary to Mr. Tallman's testimony, this does not mean I would claim later wind units should be assessed higher integration charges than current ones. Rather, as more wind resources are added, a new charge should be computed and applied to all wind resources.

I do agree, however, that GRID may not provide the best means of assessing the wind integration cost. I also accept his proposal to correct the error in the Company's filing related to the excluded wind resources. Based on his figure of 1200 mW of installed wind capacity, the Chart on page 192 of Appendix J, results in added reserve requirements of 10 mW. Applying this to the equation provided on page 193, of Appendix J, results in a wind integration charge of $.22/mWh. Adding in the excluded wind energy, results in a total wind integration cost of $1,242,997 less than proposed by the Company. I recommend this wind integration adjustment be applied to the 2008 test year.

Q. PLEASE COMMENT ON HIS PROPOSAL TO UPDATE THE TEST YEAR BASED ON THE NEW BPA CHARGES.

A. It is my understanding that this rate change has not yet been approved, and it won’t go into effect until October, 2008 if approved.

<u>Corrections to Rebuttal Testimony</u>

Q. DO YOU HAVE ANY CORRECTIONS TO THE REBUTTAL TESTIMONY YOU FILED ON MAY 9, 2008?

A. Yes. On page 4, line 71, I stated that the Company started no coal plant planned outages in January from 1990 to present. I have reexamined the data and found that one outage was started in January in 1993. I also found some minor revisions to Exhibit CCS 4.1R were necessary. I provide those in Exhibit CCS 4.1RSupplemental. In the exhibit I also show the start dates for the Company’s Alternative 2 planned outage schedule.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.