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August 25, 2009

Via Electronic and US Mail

Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem OR 97308-2148

Re: In the Matter of PACIFICORP 2010 Transition Adjustment Mechanism
Docket No. UE 207

Dear Filing Center:

Enclosed please find the original Surrebuttal Testimony of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities in the above-referenced docket.

The confidential pages of this testimony have been provided under separate seal.

Thank you for your assistance.

Sincerely,

/s/ Brendan E. Levenick
Brendan E. Levenick

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Surrebuttal Testimony of Randall J. Falkenberg on behalf of the of the Industrial Customers of Northwest Utilities upon the parties, on the service list, by causing the same to be deposited in the U.S. Mail, postage-prepaid, and via electronic mail.

Dated at Portland, Oregon, this 25th day of August, 2009.

Sincerely,

/s/ Brendan E. Levenick
Brendan E. Levenick

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2010 Transition Adjustment Mechanism	)
	)

SURREBUTTAL TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

August 25, 2009

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A. Yes. I am the same person who filed testimony in this case on July 14, 2009, on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I provide an update of ICNU's Net Variable Power Cost ("NVPC") recommendations in this case, and comment on the Company's rebuttal testimony, filed August 11, 2009.

Current Status of Disputed Issues and Company Update

Q. PLEASE SUMMARIZE ICNU'S CURRENT POWER COST RECOMMENDATIONS.

A. Table 1 on the following page shows my current recommendations.

Q. HAS THE COMPANY'S REBUTTAL TESTIMONY REDUCED THE NUMBER OF CONTESTED ISSUES?

A. Yes. The Company has implemented some of my adjustments. In a few cases I have eliminated a recommended adjustment based on new information provided by the Company. There are also other areas, where ICNU and the Company are at least in partial agreement, as will be discussed later.

Table 1
Summary of Recommended Adjustments - $

		Total Company	Est. Oregon Jurisdiction
			SE 25.00%
			SG 26.88%
I. GRID (Net Variable Power Cost Issues)			
	PacifiCorp Request NPC	**1,095,399,869**	**$272,397,235**
A. GRID Market Caps			
A.1a	**GRID Market Caps**	**(9,874,705)**	**(2,561,449)**
B. GRID Commitment Logic Error			
B.1a	**Correct Improper Screens**	**(2,191,824)**	**(568,548)**
B.2a	**Changed Start Costs**	**(1,385,031)**	**(359,270)**
B.3a	**Start Up Fuel Energy Value**	**(5,461,541)**	**(1,416,697)**
C. Long Term Contract Modling			
C.1a	**Call Option Sales Contracts**	**(4,378,535)**	**(1,135,770)**
C.2a	**Biomass**	**(654,987)**	**(169,900)**
C.3a	**Morgan Stanley Call Options**	**(3,057,000)**	**(792,971)**
C.4a	**GP Camas**	**(895,753)**	**(232,354)**
D. Hydro Modeling			
D.1a	**Hydro Input Corrections**	**(4,581,496)**	**(1,188,417)**
E. New Resource Modeling			
E.1a	**Chehalis Modeling**	**(1,556,321)**	**(403,702)**
F. Transmission Modeling			
F.1a	**Cal ISO Fees**	**(11,175,680)**	**(2,898,916)**
F.2a	**Non Firm Transmission**	**(1,009,227)**	**(261,788)**
F.3a	**STF Transmission Link Test Year Synchronization**	**(5,231,991)**	**(1,357,152)**
F.4a	**Other Transmission Adjustments**	**(860,240)**	**(223,142)**
G. Other NVPC Adjustments			
G.2a	**Thermal Generator Performance Inputs**	**(518,472)**	**(134,489)**
G.3a	**Other Wind Resource Contracts**	**(383,454)**	**(99,466)**
G.4	**Staff Coal and Other Hydro**	**(24,046,241)**	**(6,237,475)**
H. UM 1355 and Other Outage Rate Modeling Issues			
H.1a	**Planned Outage Schedule**	**(2,989,301)**	**(775,410)**
H.3a	**Ramping**	**(545,865)**	**(141,595)**
H.4a	**Minimum Loading and Deration**	**(4,517,880)**	**(1,171,915)**
H.5a	**Combined Cycle Plant Outage Rates**	**0**	**0**
I. Corrections			
I.1a	**Huntington Coal Error**	**(19,290,071)**	**(5,003,748)**
Subtotal NVPC Adjustments -		**(104,605,615)**	**(27,134,174)**
Allowed - Final GRID Result*		**990,794,254**	**245,263,061**

Q. PLEASE IDENTIFY THE ADJUSTMENTS WHERE ICNU AND THE COMPANY ARE NOW IN AGREEMENT.

A. Exhibit ICNU/201 shows my original Exhibit ICNU/108, but with indications of the current level of agreement in the Company and ICNU position. I am satisfied with the Company's implementation of the following adjustments: B.6 (Remove Start Up Operating & Maintenance ("O&M")); E.18 (Chehalis Modeling); E.19

(Mountain Wind QF)[1/]; G.26 (Regulating Margin); G.31 (SCL Stateline Reserves); H.34 (WE WD Outage Rates); H.38 (Currant Creek and Lake Side EFOR); H.39 (Gadsby $EFOR_d$); H.40 (Long Outages); and I.42 (Other Unverified Errors). These adjustments are marked with an "A" on Exhibit ICNU/201. These adjustments reduce NVPC by $3.34 million on an Oregon basis.

Q. PLEASE IDENTIFY ANY ADJUSTMENTS THAT YOU ELIMINATED OR ARE NOW SATISFIED WITH THE COMPANY'S MODELING.

A. Based on review of the Company's testimony, I no longer believe the following adjustments are necessary: F.23 (Arizona Transmission Pro-Forma); F.25 (Prior Period Adjustment); G.27 (Gadsby 1 Minimum); H.36 (Ramping Other Units)[2/]; and H.41 (Combined Cycle Planned Outage Deration). These are marked with an "E" on Exhibit ICNU/201. These adjustments sum to $647,000 Oregon.

Q. HAS THE COMPANY INTRODUCED ANY NEW ADJUSTMENTS INTO ITS UPDATE THAT YOU DISAGREE WITH?

A. Yes. The Company proposes an update of the Chehalis start up cost and fuel energy, though it characterizes it as a correction (Correction 9 on PPL/105). I believe this is an improper update because the Company applied Integrated Resource Planning ("IRP") assumptions for Chehalis modeling in several prior studies in both Oregon and other states and now seeks to replace this data with unsupported and highly questionable assumptions. I disagree with the adjustment for curing the duct firing error (Correction 7 on PPL/105). I also disagree with Correction 4 on PPL/105 (Combined Cycle Plant Planned outages) because the

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1/ Note, however, I do not agree with the Company's characterization of this as an update, as the Company had a new forecast of the projects output since December 2008.

2/ Note that in this case, I recommend the Company remove this adjustment from outage rates in its next general rate case, and incorporate it into a load adjustment.

Company again relies on completely unsupported information. Finally, I don't believe the Company has implemented all of the error corrections required. I have identified a correction the Company didn't include for Huntington coal costs.

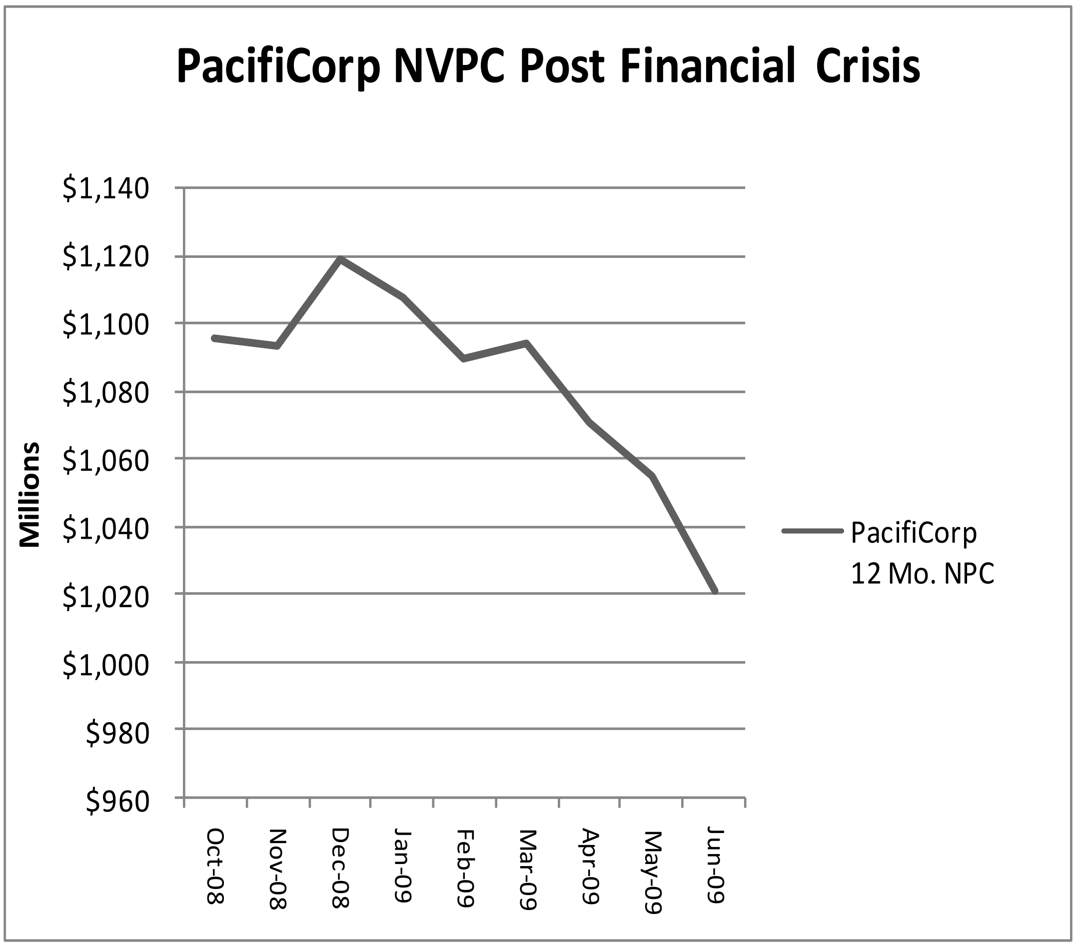
Reasonableness of NVPC Recommendations

Q. ON PAGE 3, MR. DUVALL ASSERTS THAT THE COMPANY'S NVPC RECOMMATION OF $1.095 BILLION IS "REASONABLE." HE ALSO CONTENDS YOUR RECOMMENDATION OF $995 MILLION IS NOT REASONABLE COMPARED TO RECENT ACTUAL POWER COSTS. PLEASE COMMENT.

A. Mr. Duvall cites the 12 months ended May 2009 actual NVPC result of $1.055 billion. However, Mr. Duvall ignores many significant factors, specifically the severity of the current economic downturn and its dramatic impact on market prices for gas and power. The 12 month period he discusses contains several months of data before the "*economy fell off a cliff*" in fall 2008. Clearly, there is no basis for assuming that actual cost results prior to late 2008 will be reflective of test year conditions. As such, Mr. Duvall's reference to actual power costs provides no guidance whatsoever.

Q. IS MR. DUVALL'S $1.055 BILLION THE MOST RECENT ACTUAL NVPC DATA AVAILABLE?

A. No. Mr. Duvall did not report that for the 12 months ended June 30, 2009, actual power costs were $1.021 billion, or $34 million less than the amount he quoted in testimony. Further, for the first six months of 2009, actual NVPC was only $438 million, almost $100 million less than the same period in 2008. When annualized, these results indicate an actual 2009 NVPC of $876 million. The figure below shows that since the financial crisis of late 2008, PacifiCorp's net power costs (based on a rolling 12 month average) have been declining sharply. I think this illustrates that recent actual NVPC results are showing a downward trend, and that focus on actual NVPC in comparison to normalized is not that useful. These are very turbulent and volatile times, and reliance on actual NVPC data is a gamble.



It is fair, however, to ask why Mr. Duvall didn't discuss the most recent actual data, as it should have been available to him. In Utah Docket No. 07-035-93, Mr. Duvall filed testimony on May 9, 2008, reporting NVPC figures for the 12 months ended March 31, 2008, a span of no more than 39 days. Mr. Duvall contended than that actual NVPC was increasing and that the recent figures supported his results in that case. In this case, however, Mr. Duvall did not report the less favorable June results, even though the time span was 41 days. A comparison to actual is one of the keystones of Mr. Duvall's NVPC argument, I question why he didn't insist on using the most recent actual results. In the end, I believe the Commission should focus on the merits of the issues in this case rather than the use of selective trends on power costs.

Q. HOW DO MR. DUVALL'S UPDATED FIGURES COMPARE TO NVPC FORECASTS THE COMPANY HAS USED IN OTHER STATES?

A. Mr. Duvall's own power cost studies in recent cases call into question his proposed 2010 NVPC of $1.095 billion. In the June 2009 Utah General Rate Case filing Mr. Duvall is projecting a total NVPC of $999 million for the 12 months ended June 2010. For the six month period shared by both the Utah and Oregon test years, (January through June 2010) the Utah test year results are some $30 million lower than the Oregon test year results, despite a six fold increase in wind integration costs.

In the Company's February 2009 Wyoming PCAM filing, the Company produced a GRID study showing total NVPC of $1.031 billion for the 12 months ended November 2009. Recently the Company agreed to a settlement in that case based on total NVPC of $995 million. While prior NVPC was arguably increasing at a rate of $60 million every six months, current studies show NVPC is declining. Indeed, Mr. Duvall's recent Wyoming update NVPC study showed a decline of nearly $60 million attributable to the economic downturn.

Coal Fired Generation

Q. PLEASE ADDRESS MR. DUVALL'S ASSERTION ON PAGE 4 THAT THE ICNU FINAL GRID STUDY CONTAINS EXCESSIVE COAL GENERATION, AND ITS NVPC IS UNDERSTATED BY $55 MILLION.

A. Mr. Duvall presents an exaggerated, misleading and otherwise meaningless comparison. He uses an incorrect baseline period, understates actual coal generation, fails to account for system changes and load growth, and overstates the amount of coal fired generation under ICNU's proposals. Mr. Duvall is really proposing an arbitrary, result oriented standard for selecting adjustments, based on total coal-fired generation, which the Company has not applied to its own studies. For example, Mr. Duvall failed to disclose the fact that his own 2009 Utah GRID studies show coal generation far closer to my current results than to the four year historical results he discusses.

I will demonstrate that my projected coal fired generation is reasonable compared to recent actual results and that coal generation by itself is not a valid metric for evaluating power cost adjustments.

Q. ARE THERE ANY OBVIOUS PROBLEMS WITH MR. DUVALL'S "$55 MILLION" CLAIM?

A. Yes. This claim is premised on a completely unsupported assumption that incremental coal generation produces a margin of $40/MWH. Mr. Duvall failed to recognize that most of the coal generation increase produced by the market cap, contract shape and screen adjustments occurs between 1 AM and 5 AM, when actual margins are substantially lower than $40/MWH. He also unfairly compares my study against a four year average, when the proper comparison is against his own study. Both studies show more coal generation than occurred in the four year period.

More than 75% of all of the incremental coal energy resulting from my adjustments occurs during the low margin "graveyard shift" hours. Mr. Duvall could have easily performed an analysis to quantify this effect, but chose not to. Using GRID's own calculation of the cost and market value of coal energy shows the <u>entire the impact of the incremental coal is only $27 million, not $55 million</u>. Mr. Duvall's data is exaggerated by more than 100%.

Because Mr. Duvall's update incorporates in some fashion at least nine adjustments I've proposed, he increases his own coal generation by an additional 200,000 MWH and my own update study reduces coal fired generation. This means that the additional coal I recommend produces at most an incremental margin of $15 million. Mr. Duvall's $55 million claim is so overstated as to be meaningless.

Q. IS COMPARISON TO THE FOUR YEAR AVERAGE COAL GENERATION REASONABLE AT ALL?

A. No. If the system was static with little load growth, no new capacity, or any operational changes, then a four year average of coal generation could be a valid metric. However, over the four year period examined by Mr. Duvall, the system changed substantially, a point that Mr. Duvall did not even consider.

In fact, there are some very good reasons that Mr. Duvall's own studies (in Oregon, Utah and Wyoming) have more coal generation than the four year average. We both agree that coal generation in 2010 should be greater than the four year period ended June 30, 2008. The only question is by how much.

Mr. Duvall's analysis is also incorrect and distorted in a number of other ways. The table below summarizes the most significant problems in his analysis.

Table 2
Coal Fired Generation

Duvall Reported Actual 48 Months		Annual MWH
Ending June 30, 2008		45,036,525
Understatement Errors		182,883
Corrected		45,219,408
Changes in Test Year		
Load Growth Impact		298,888
Combined Cycle Reserve Allocation		535,656
Plant Factors		91,212
	Adjusted	46,145,165
ICNU Final Run		46,400,612
Less Start Up Energy		(71,668)
	Net	46,328,944

Q. PLEASE EXPLAIN TABLE 2.

A. This table starts with Mr. Duvall's reported average annual coal generation for the 48 months ended June 30, 2008 - 45.0 Million MWH. However, this figure is overstated because it includes energy lost due to non-running station service and ramping. Without adjustment, GRID would not reflect either of these factors, and it would always appear that GRID was overstating coal generation. However, the Company has made adjustments to GRID to account for this energy. While I questioned whether ramping should be part of the outage rate calculation, I agree that the energy associated with it should be accounted for in the model, and have proposed it be reflected as a load modifier. As I no longer oppose the ramping outage rate adjustment for this case[3/] it is appropriate to reverse these losses out of the Company's actual reported coal generation in order to make a fair comparison to the GRID model results.

Q. PLEASE EXPLAIN THE NEXT ENTRIES ON TABLE 2.

A. Another problem with Mr. Duvall's comparison is that he ignores the changes to the system that occurred between the four year period and the 2010 test year. While there are many changes to consider, some of the most obvious, and significant changes are load growth and the introduction of the Currant Creek, Lake Side and Chehalis combined cycle plants on the system.

Load growth naturally increases coal generation. I estimated the impact to be approximately 300,000 MWH by running GRID with the average loads during the four year period. The new combined cycle plants also allow for increased coal fired generation because the new gas plants are now carrying reserves that were previously assigned to coal units. During the four year period, Chehalis was never online, Currant Creek was only online for two years and Lake Side for only nine months. From GRID, I estimate the impact to be 536,000 MWH.

There have also been capacity increases, and the Company and I both agree there should be outage rate reductions to remove two very long outages. These factors also increase the amount of coal generation in the test year. In the end, these factors would increase the "comparable" coal generation levels to approximately 46.15 million MWH.

[3/] Excepting the case of the Bridger plant for which the Company has no accurate data to estimate ramping losses.

Naturally, there are many other factors that would impact coal fired generation – the decline in hydro, the increase in wind generation, fuel price changes, and others factors. Because there are so many factors that vary between the test year and the four year period, reliance on the four year period in this case is really quite meaningless. As a result, it makes much more sense to rely on recent data results, if we rely on history at all. This is why I cited the more recent data which is quite in line with my projections in my direct testimony. Based on the 12 months ended June 30, 2008, PacifiCorp's actual coal-fired generation was 46.0 million MWH. For the 12 months ended March 31, 2008, the actual coal fired generation was 46.3 million MWh.

Q. EXPLAIN THE LAST ENTRIES IN TABLE 2.

A. Mr. Duvall mistakenly overstated the amount of coal energy contained in my final July GRID study. He did so because he incorrectly assumed that I failed to account for the energy offset by the combined cycle start up energy I modeled in Adjustment B.7. Mr. Duvall testifies at page 24 that GRID does not reflect any loss of energy associated with ramping down units while gas-fired units are ramping up. He is completely wrong about this, as could have been seen by reviewing my workpapers. The GRID scenarios I used to model the start up energy for the combined cycle units do show a reduction in coal-fired generation. While I implemented this adjustment as a financial adjustment only, it was based on a reduction in coal energy. This is shown on Table 2 as a reduction of about 72,000 MWH.

In the end, there is little reason to be concerned that the final GRID studies produce "excessive" amounts of coal generation. Instead, I believe this shows a basic problem with the Company's approach to GRID. The Company relies on the model for power cost studies and for rate setting, almost without question. However, in instances where the Company does not like the results, they are quick to abandon the model and impose arbitrary and unsupported assumptions that override the model's logic to drive the NVPC final results upwards.[4/]

Q. IS MR. DUVALL CONSISTENT IN HIS APPROACH?

A. No. In the GRID studies Mr. Duvall filed in the 2008 Utah general rate case ("GRC"), Mr. Duvall's 2009 Test Year GRID studies showed 45.98 million MWH and 45.97 million MWH in his December 2008 and March 2009 studies. In his updated NVPC study in this case, he includes 45.7 million MWH. Mr. Duvall's recent results differ from mine by only 0.9-1.5%. This small difference contradicts his claim that I have understated NVPC by $55 million.

Q. HAS THE AMOUNT OF COAL GENERATION INCLUDED IN YOUR AUGUST UPDATE BEEN REDUCED FROM THE LEVELS IN THE JULY STUDY?

A. Yes. As noted above, the market cap adjustment is by far the largest source of increased coal energy. Based on the Company's updated model, the changes in forward prices and other inputs substantially reduce the impact of market caps on coal generation. While the market caps increased coal generation by 623,000 MWH in the Company's original filing (which was the basis for my July study),

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4/ Other examples include wind integration modeling, Mr. Duvall's arguments against the start up energy adjustment, and the modeling of the hydro reserve input parameter.

in my August update, the increase is only 354,000 MWH, or a reduction of 43%. The same appears to be true of other adjustments, such as non-firm transmission. My final GRID study contains about 46.2 million MWH of coal generation. Consequently, Mr. Duvall has greatly exaggerated the importance of this issue.

Q. ASIDE FROM THE FACTORS DISCUSSED ABOVE, ARE THERE ANY OTHER REASONS WHY THE FOUR YEAR PERIOD IS NOT RELEVANT TO THE ISSUE OF COAL GENERATION AS IT CONCERNS THE MARKET CAPS?

A. Yes. Mr. Duvall has completely ignored the fact that his market cap limits are based on analysis of spot market sales for the <u>12 months ended June 30, 2008</u>. This means that any comparison to coal generation should be based on the same one year period, not the four year period he discussed. Based on the underlying premise of the market caps, and the factors discussed above, the four year average coal generation in the four year period is no longer a meaningful yardstick.

Q. DOES MR. DUVALL UNDERSTATE COMBINED CYCLE GAS GENERAITON?

A. Yes. Mr. Duvall's GRID study understates the amount of combined cycle gas generation for Currant Creek, Lake Side and Hermiston. While his proposed test year contains only 6.3 Million MWH, for the 12 month period ended December 31, 2008, actual generation for these units was 7.5 Million MWH. Because some of the adjustments (particularly market caps) also impact gas generation, Mr. Duvall is ignoring this problem with his test year. With the market cap, and other adjustments, my July and August GRID study are in closer agreement with recent actual results.

Market Caps

Q. DOES MR. DUVALL PROVIDE ANY ADDITIONAL ARGUMENTS OPPSOSING THE MARKET CAP ADJUSTMENT?

A. No. Mr. Duvall rests his case on Test Year coal-fired generation. In effect, he is admitting the market caps are a "fudge factor" that the Company (at its sole discretion) can use to derive "acceptable" power costs. The Company never actually considers the four year average coal generation in determining the market caps, and freely exceeds the historical level in their own studies. In other words, the Company' approach is purely "result oriented."

Q. DID MR. DUVALL RESPOND TO ANY OF THE OTHER MARKET CAP ANALYSES RAISED IN YOUR DIRECT TESTIMONY?

A. No. Mr. Duvall did not address the substantial disparity between grave yard shift sales volumes in GRID as compared to actual data. Mr. Duvall rests his argument on the small (1.5% or less) difference in coal generation, as opposed to disparities in sales volumes that exceed 100%.

Further, Mr. Duvall presented no evidence demonstrating a lack of market liquidity, the theoretical underpinning of the market cap adjustment. Nor does he address the enormous bid-ask spread implied by his market cap assumptions.

Q. DOES THE COMPANY USE MARKET CAPS CONSISTANTLY IN ITS OTHER MODELS OR STUDIES?

A. No. The Company's approach to market caps changes depending on the circumstances. The Company applies the market caps for purposes of computing avoided costs for QFs (in situations where GRID is the basis for avoided costs), and in retail rate cases. The Company, however, has not used market caps in studies evaluating new capacity additions. For example, the Currant Creek, Lake

Side, and the numerous wind projects undertaken in the past few years did not consider market caps. Further, the Company's IRP model, called "PAR," does not model market caps either. As a result, the Company is adding capacity premised on an assumption that all energy created by the resource may be sold into the market. However, once the Company completes the projects and includes them in rates, the market caps are then applied. There is no justification for applying market caps once a new resource comes on line, after ignoring them in the resource selection process.

Further, the Company's approach biases avoided costs used in setting QF rates in some instances. Indeed, in a recent Wyoming case, Mr. Widmer, originator of the market cap modeling approach, stated the market caps were no longer needed, and biased avoided costs:

> Inclusion of market caps produce avoided cost prices that are lower than appropriate because they result in far more low cost coal generation being included in the marginal resources being displaced by the QF than would be true in actual operation of the PacifiCorp system, which artificially lowers the avoided cost that is being calculated by the model.

Wyoming Docket No. 20000-342-EA-09, Direct Testimony of Mark Widmer, page 12.

In effect, the Company simply uses the market caps in a manner designed to increase power costs and stifle competition, while ignoring them for its own resource selection decisions. I recommend the Commission eliminate market caps in this case and not allow the Company to reinstate them, unless they provide evidence of market illiquidity and the Company also uses market caps consistently in the resource selection process.

Q. HAVE YOU UPDATED THE MARKET CAP ADJUSTMENT?

A. Yes. The changes in the forward price curve and other updates substantially changed the impact of this adjustment. The updated adjustment is shown on Table 1, as Adjustment A.1.a.

Daily vs. Monthly Screens

Q. WHY DOES THE COMPANY OPPOSE THE USE OF DAILY SCREENS?

A. Mr. Duvall makes several arguments. He states that GRID is not affected by daily variations in loads, market prices and resources. He suggests there is some precedential argument for using monthly screens because they were used in UE 199. He also cites some minor concerns with my implementation of daily screens. I will address each point.

First, it is very significant that Mr. Duvall does not dispute the fact that the screens I produced do a better job of eliminating the extra costs created by the GRID logic error. Nor does he dispute the fact that it takes virtually no extra work to implement daily screens. In the end, Mr. Duvall proposes that the Oregon Public Utility Commission ("OPUC") allow the Company to collect additional money from customers simply because the GRID model contains a mathematical error. Commission acceptance of his position would diminish any incentive for the Company to ever correct the error. It is very important to remember that this GRID error (acknowledged by the Company) is a one way street: it can only increase power costs. The Company proposes to take short cuts that allow it to profit from its GRID error. I propose that they be required to do the best possible job of correcting it.

Q. IS MR. DUVALL CORRECT THAT GRID IS NOT AFFECTED BY DAILY VARIATIONS IN LOADS, MARKET PRICES AND RESOURCES?

A. No. Resource availability changes from day to day because of planned outages, Short Term Firm and Long Term Firm transactions. Loads (and hydro which is shaped by load) do vary on a daily basis. Market prices vary by day of the week. Mr. Duvall would suggest that if a combined cycle plant runs Monday through Friday, it should also be required to run on the weekend. Further, call option sales also vary by day of the week, and purchase contracts may also vary on a daily or even hourly basis. Further, wind resources also vary by day of the month, though this may be due to another data input mistake the Company has made. If Mr. Duvall was correct, then my analysis would likely produce the same screen for every day of the month. Further, one must ask why, if Mr. Duvall were correct, does the logic already built into GRID attempt to perform a daily (even hourly) optimization of unit starts and stops?

The confidential figure below illustrates why daily, rather than monthly screens are appropriate. This figure shows the daily dispatch benefits[5/] for Lake Side and the associated start up costs, based on the data Mr. Duvall used to compute his screen for May 2010. During that month, Mr. Duvall's monthly analysis showed no screen was warranted. A daily analysis would produce much different results.

When start up costs exceed daily dispatch benefits, it makes no sense to start up the resource – it is "underwater".[6/] Based on Mr. Duvall's data, however,

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5/ The difference between the value of the energy produced less the cost of fuel.

6/ In this case, Lake Side is shutting down and starting up ever day, already.

there are many days in May 2010 when Lake Side should not be running at all, including one day when a start up produces a loss of [redacted], not even counting the additional start up costs. Under Mr. Duvall's method, no screen is used because there are some days when dispatch benefits are quite substantial. In his approach, this outweighs the days when dispatch benefits are negative, or less than the start up costs. In a proper analysis, there are many days (mostly weekends) when Lake Side should not be started at all, and other days when screens would lower costs. In the end, the daily screening adjustment reduces the cost due to the GRID logic error by $168,000 in May 2010 plus avoidance of substantial additional start up O&M expenses. Even if this does not seem like a large amount of money, it is important to realize that, as market prices increase, the problems related to logic error will increase. In the UE 199 July update, the overall impact of the screens used was more than $25 million dollars, due to the much higher market prices at the time.

[redacted]

Q. PLEASE COMMENT ON MR. DUVALL'S SUGGESTION THAT DAILY SCREENS WERE NOT USED IN UE 199.

A. Mr. Duvall ignores the fact that UE 199 was settled with a "black box" and establishes no precedent. Further, in my testimony is UE 199, I characterized my screens as only an "interim solution" and recommended the Company be required to correct the GRID logic before the next Transition Adjustment Mechanism ("TAM") case. The Company failed to do so. If Mr. Duvall's proposal is accepted, the Company will have no incentive to correct the problem, and will continue to profit from it.

Q. PLEASE COMMENT ON MR. DUVALL'S VARIOUS CRITICISMS OF YOUR SCREENING METHOD.

A. Mr. Duvall says the Commission should not adopt my proposed screens without adjustment. I already pointed out in my direct testimony that the screens used in this case should be updated whenever significant factors change, such as forward prices. The Company updated the screens in its filing, and the Company's Manager of Net Power costs stated during the conference call on August 14, 2009 that the screens need to be recomputed when new updates are performed. I have also made some minor improvements to my recommended screening methodology in response to some of Mr. Duvall's criticisms.

Q. PLEASE ADDRESS MR. DUVALL'S OTHER CONCERNS.

A. Mr. Duvall states the screens are "unverified" and suggests the Company does not know how to apply them. I find this surprising, as I have always been willing to talk to the Company to answer any questions regarding my GRID studies. I also provided highly detailed workpapers which can be applied directly to develop the new screens. I also provided a detailed written description of the screening methodology. In any case, I have "verified" the screens in the sense that they generally produce a reduction to NVPC from running GRID quite close to the levels anticipated by the hourly analysis. Finally, the Company obviously understood the daily screens well enough to make some criticisms of them.

Mr. Duvall makes four other criticisms the screens: 1) do not consider minimum up times; 2) do not look ahead for a full 24 hours; 3) fail to account for the last hour to show positive margins; and 4) may incorrectly apply start up costs. As a general matter, any shortcoming in the screens will <u>overstate</u> NVPC because they will fail to remove all possible uneconomic generation.

As for the minimum up time (item 1 above), the logic I uses makes sure a unit will not start unless it is economic to run for at least six hours (this is the minimum up time for Lake Side and Currant Creek).[7/] Further, GRID already contains logic to enforce minimum up times, suggesting this criticism is superfluous. The same appears to be the case for the "last hour" criticism (item 3.) My analysis of the final dispatch for screened units does not show any situation where the minimum up time was violated or where the "last hour" problem occurred. I would certainly not object to the Company addressing this issue, in implementing the final screens, if it can be shown to be necessary.

As for start ups (item 4), I agree that the screens in the July filing allowed for a limited number (7) of unnecessary starts. Correcting this would have a minimal effect (less than $31,000 Oregon in my July filing) and would reduce NVPC. As for looking forward longer than six hours (item 2), I have now

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[7/] The look ahead period can be easily changed to accommodate units such as Chehalis that have different minimum downtimes. Chehalis generally does not require screens at present, however.

improved the method to address this issue. No matter what Mr. Duvall may say, the screens I propose are more effective at reducing the excess costs in GRID than his monthly screens. Further, the shortcomings he has identified would reduce NVPC if corrected formally in the screening methodology.

Q. JUST FOR THE RECORD, ARE YOU STATING THE SCREENING METHOD YOU HAVE DEVELOPED IN THIS CASE SHOULD BE USED FOR ALL FUTURE CASES BY THE COMPANY?

A. No. Again, this is an <u>interim</u> solution, which I recommend be applied until the Company corrects the GRID model, or a better screening approach is developed. There is no excuse for requiring customers to pay the Company more money because the GRID model has a logic error. Assuming that the problem still occurs in future cases, I would recommend trying to further improve the model or screening method.

Q. ASSUMING A SOLUTION TO THE GRID LOGIC ERROR CANNOT BE IMPLEMENTED BY THE NEXT CASE. DO YOU HAVE ANY OTHER RECOMMENDATIONS?

A. Yes. I recommend the Commission require a minor GRID modification to export the hourly sum of fuel and purchase power costs less sales revenue. This would facilitate the production of screens allowing time savings for all parties.

Q. HAVE YOU UPDATED YOUR RECOMMENDED SCREENS?

A. Yes. Adjustment B.1.a presents my screening adjustments. Unlike the July filing, the screening adjustment for combined cycle plants was based on my last series of GRID runs, after reversing the Company screens. My analysis indicated no screen was needed for Chehalis or Lake Side. In fact, the Company's monthly screen actually increased power costs because it forced numerous unnecessary shut downs for Lake Side. The analysis of daily screens helped to diagnose this problem. Adjustment B.2.a shows the impact of the reduced number of starts on NVPC. I also developed screens for Gadsby CT and Steam units, and provide a screening adjustment for the duct firing capability. Mr. Duvall seemed to complain my original screens were not complete. This provides a complete, final set of screens.

Start Up Energy

Q. PLEASE EXPLAIN MR. DUVALL'S OPPOSITION TO MODELING THE START UP ENERGY OF COMBINED CYCLE PLANTS.

A. Mr. Duvall continues to recommend that the cost of start up fuel be included in GRID, while excluding the energy produced during the start sequence. He argues that: 1) within an hour there is no market for the energy; 2) that hydro follows the ramp up of gas plants; and 3) there is a double counting of the energy because GRID does not reflect a ramping down of coal energy as gas units are ramping up.

Q. DO YOU AGREE?

A. No. Mr. Duvall again relies on unsupported assertions rather than any analysis or evidence. As I pointed out earlier, Mr. Duvall is simply wrong as regards GRID's failure to ramp down coal plants. In fact, in the studies I used to quantify the value of this adjustment, GRID did "ramp down" coal plants, as well as other resources.

His arguments concerning hydro and the lack of an intra-hour market are mutually contradictory. If hydro is "following" the ramp up of the gas plant, it is incorrect to assume the energy has no value. Indeed, as the combined cycle plant ramps up, hydro output would decline. The hydro energy not used in one hour is stored and can be used in a subsequent hour to offset coal or gas generation or even be sold in the market. In all likelihood, that energy will have a higher value when it is ultimately used than when it was actually produced. Consequently, his argument concerning the lack of an intra-hour market is inconsistent with his assumption that hydro provides the load following capability. It does not matter within an hour whether the hydro energy is used or stored. The start up of gas and subsequent ramp down of hydro will save the energy created by the start sequence.

Q. MR. DUVALL HAS ALSO SUGGESTED THAT THE RAMPING UP OF GAS UNITS CREATES THE NEED FOR MORE RESERVES. IS THIS ACCURATE?

A. No. The figure below compares the average amount of regulating margin (in MW) allocated to PacifiCorp generators in 2008 on days when Currant Creek and Lake Side started up and on those days where they did not start up. The figure shows that days where these units started simply do not show any large spikes in regulating margin allocations, as might have been inferred from Mr. Duvall's testimony. In fact, the days when these units did not start had higher regulating margin allocations than the days where they did start. This is likely because the units were already running those days, due to higher loads. In any case, there is no basis for concluding that increased regulating margin requirements diminish the value of start up energy. I did, however, model added reserve requirements for the start up energy, so it is accounted in my adjustment. Adjustment B.3.a provides my update of the value of the start up energy adjustment.

[redacted]

Q. ASSUMING MR. DUVALL'S ARGUMENTS CONCERNING RESERVES, INTRA HOUR MARKETS AND OTHERS HAVE MERIT, CAN YOU QUANTIFY THE IMPACT ON YOUR ADJUSTMENT?

A. At most, these arguments go the level of the start up energy adjustment, not whether it should be adopted. I can place an upper limit on the value of the factors discussed by Mr. Duvall. His arguments here are similar to the assumptions he made in his current Utah testimony concerning intra hour costs resulting from wind integration. As start up energy should be less volatile and uncertain than wind energy, the Company's assumed intra hour reserve costs provide an upper limit on the costs imposed by start up energy. Based on his assumed value of [redacted] MWH, the reduction to Adjustment B.3.a would be only $192,000 on an Oregon allocated basis. While I do not adopt his Utah assumptions, this does illustrate his arguments are, once again, exaggerated.

Hydro Modeling

Q. DOES THE COMPANY AGREE WITH YOUR PROPOSED CONDIT ADJUSTMENT?

A. In part. The Company agrees that the decommissioning date has been delayed again, but now assumes the decommissioning will begin by October 1, 2010. Given the recent delays of the decommissioning date, I see no resolution to this issue. If, however, the Company does obtain the necessary permits to commence decommissioning before the final update in this case, and can document that the process will begin at a date certain in 2010, I would not object to reflecting the actual and expected decommissioning of Condit in the test year.[8/] This should be conditioned upon a requirement that the Company defer the Condit costs and benefits if the Company does not actually decommission Condit in 2010.

Q. DOES THE COMPANY AGREE WITH YOUR PROPOSED BEAR RIVER ADJUSTMENT?

A. No. Mr. Duvall contends that recent events and new operating constraints impact the Company's ability to use the Bear River resource. This however, contradicts discovery responses provided earlier this year, wherein the Company stated that there were no changes in the physical characteristics, engineering or operational constraints impacting the output of these projects.[9/] As a result, I believe there is substantial doubt concerning the Company's position.

8/ I recognize this is not in perfect alignment with the TAM Guidelines, but feel an exception is appropriate in this case if all parties agree to it. I see no reason why the Company should object.

9/ Utah Docket No. 08-035-38, Response to CCS 30.6 and 30.7. The Utah case also reflected substantially reduced generation from the project. See Exhibit ICNU/202.

Q. DOES THE COMPANY AGREE WITH YOUR PROPOSED HYDRO RESERVE INPUT PARAMETER ADJUSTMENT?

A. No. However, the Company acknowledges that this input deserves additional consideration, and proposes to come back next year with a better approach than that which underlies its current, unsupported inputs.

Q. PLEASE COMMENT.

A. Mr. Duvall presents no real rebuttal to my demonstration that the regulating margin requirements are greatest during the pre-dawn hours of the cold weather months. If the Company wishes to develop a better method to derive these inputs, then it would certainly have the chance to do so in future cases. In the meantime, the Commission should not rely on these erroneous, unsupported and outdated inputs. Adjustment D.1.a presents my updated hydro modeling adjustments. Finally, the Company's proposal seems rather disingenuous to me. Mr. Duvall recently proposed a complete change in the Company's hydro modeling in its 2009 Utah case, which would render this adjustment moot. The Company should not be allowed to increase power costs now based on a promise to fix the problem in the future.

Long Term Contract Modeling

Call Option Sales

Q. DOES THE COMPANY AGREE WITH YOUR PROPOSED CALL OPTION SALES CONTRACT MODELING?

A. No. Mr. Duvall makes a number of arguments, though most were already addressed in my direct testimony. He fails to recognize that the very minor shaping adjustments I propose are a proxy to address differences in markets, forward price assumptions, and the counterparty's constraints that are unknown to the Company. Mr. Duvall does agree however, that "[t]he data referenced, as well as the strategies that the counterparties employ, are proprietary and unavailable to the Company. The Company must work with the data to which it has access." PPL/104, Duvall/26. The best and least ambiguous data the Company has access to are the actual delivery patterns, which Mr. Duvall simply chooses to ignore. Rather, Mr. Duvall continues to assume a "worst case" and "most cost" delivery pattern.

Q. HAS THE COMPANY MADE ANY NEW ARGUMENTS CONCERNING THE MODELING OF THE SACRAMENTO MUNICIPAL UTILITY DISTRICT ("SMUD") CONTRACT?

A. On page 28, Mr. Duvall also argues that if the SMUD shaping is modified, one should also begin to recognize deliveries and receipts under the provisional clause of the SMUD contract. However, the Company has never sought cost recovery of deliveries made under that contract option in prior cases, and has never established prudence. Review of this contract option clearly establishes a prima facie case that it was imprudent. Indeed, the entire contract is imprudent because the Company agreed to a below market sale of energy to SMUD in exchange for a $94 million up front payment, which it never returned to ratepayers. The Oregon Commission has partially compensated ratepayers for the ordinary SMUD deliveries by use of the $37/MWH imputed price. This is not the case for the provisional deliveries.

Q. PLEASE EXPLAIN THE PROVISIONAL CONTRACT CLAUSE.

A. Under this option, SMUD may take an additional 219,000 MWH at a delivery rate not to exceed 100 MW per hour, <u>at any time</u> during any calendar year. SMUD then may return that power at any time it desires the following year. For example, SMUD could demand 100 MW at the time of the system peak, when market prices are $200/MWH, and return the power at 3 AM in an off-peak month, a year later, when market prices are less than $20/MWH.

There are two rather obvious problems with the Company's argument concerning the provisional delivery options. First, the provisional contract option was imprudent on its face. In effect, the provisional option allows SMUD the unfettered right to "buy low" and "sell high" at PacifiCorp's expense. To my knowledge, no Commission, including the OPUC, has ever considered the provisional contract option. In fact, it is so unfavorable, that the Company has never modeled in any of its power costs studies, in Oregon or in any other state to my knowledge. See for example, Exhibit ICNU/203 which shows a copy of a data response from Wyoming Docket 20000-266-EP-07 (WIEC 1.6) that states that for ratemaking purposes the Company has always excluded the provisional energy. The same exhibit also shows a list of the assumptions as reported in the GRID Long Term Contract Attributes from UE 199, which shows that SMUD provisional return energy was excluded by the Company from its UE 199 GRID study. This can be seen by noting the "Restricted" entry is equal to one at all times. This means the SMUD provisional return energy was prevented from being included every single hour. To my knowledge, the same was true for every previous case.[10/]

10/ The Company includes the provisional inputs in GRID, I believe, because it is used for other kinds of power cost studies. The budget, for example, might include these contract deliveries as it has been excluded for regulatory purposes, but would still impact actual NVPC.

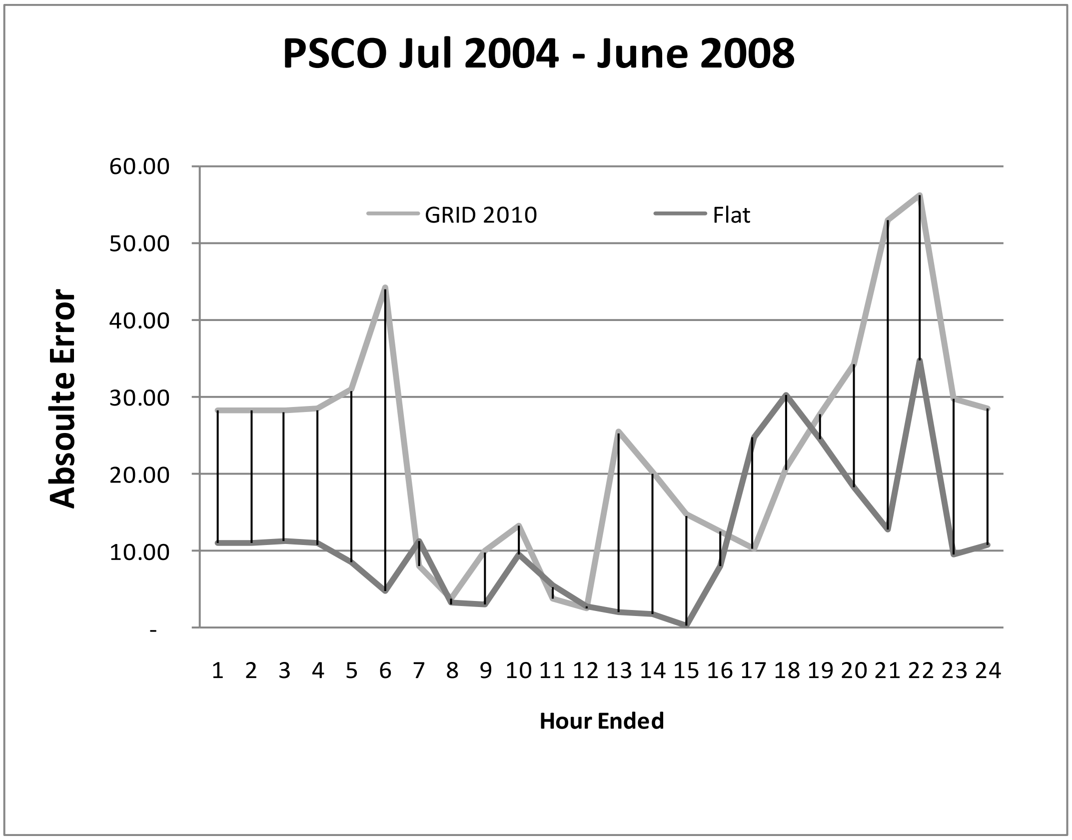
Second, to now address the provisional clause, it would be necessary to develop imputed prices reflecting a prudence determination concerning the possible high value deliveries to SMUD and the low value returns. The prudence of deliveries under that option of the SMUD contract is highly questionable, and has neither been justified by the Company nor considered by the Commission. The prior imputed prices used by the Commission would most certainly not be applicable, because it was based on the Southern Cal Edison ("SCE") contract. SCE was a straightforward sale without the egregious exchange elements of the SMUD provisional contract clause. To establish prudence, a contemporaneous exchange contract or some other method would need to be considered. As a result, I do not believe that the highly unfavorable aspects of the provisional clause can be used to justify the Company's opposition to a proper modeling of the SMUD contract and its actual pattern of delivery.

Q. MR. DUVALL CONTENDS YOU LEFT OUT SOME OF THE DATA FOR SMUD DELIVERIES. IS HE CORRECT?

A. No. The simple fact is that SMUD did not take any deliveries during the time periods which Mr. Duvall suggests may have been excluded. In fact, the entire 350,400 MWH is accounted for each year from 2004 through 2007 in the data I used. There is no missing data.

Q. MR. DUVALL CONTENDS THAT YOUR MODELING OF THE PUBLIC SERVICE COMPANY OF COLORADO ("PSCO") CONTRACT IS FLAWED. PLEASE COMMENT.

A. He refers to PPL/110 which shows actual vs. simulated deliveries for PSCO. While I agree that both the Company and ICNU modeling could be improved, his charts present a distorted analysis which does little to establish the reasonableness of his modeling. One problem with his charts is that they show a 24 hour pattern for LLH deliveries. This greatly distorts the importance of Sunday deliveries. The figure below illustrates why the approach I recommend is superior to the Company's modeling.



The figure shows that the absolute magnitude of errors (the absolute difference between actual and normalized deliveries) each hour for the Company modeling as compared to a flat profile. The Company modeling produces a total absolute error more than twice that of flat modeling. This is because the Company substantially understates deliveries in the off-peak hours, and overstates on-peak deliveries. The flat pattern is closer to actual, 19 hours of the day. The five remaining hours where the Company modeling may be slightly closer tend to be close for the flat modeling as well. The Company approach simply introduces too much error into the analysis and does not fit the data as well as a flat pattern. Adjustment C.1.a presents the updated Call Option modeling Sale Adjustment.

Biomass and GP Camas

Q. DOES MR. DUVALL AGREE WITH THE ADJUSTMENTS RELATED TO THE BIOMASS AND GP CAMAS CONTRACTS?

A. No. In both cases, he cites the TAM Guidelines as support for this position. In the case of the Biomass contract, he states the guidelines allow only for "known contracts" which he defines as those executed by the time of the Final Update. He disputes the GP Camas contract on the basis that it represents "new information" which he erroneously contends is not permitted under the TAM Guidelines.

Q. DO YOU AGREE?

A. No. The TAM Guidelines do not place any limit on the ability of the Commission to implement contract adjustments, nor do they prevent any party other than the Company from proposing such adjustments. The limitations in the Guidelines apply only to the Company. There is ample justification for this, as the Company abused the update process substantially in the past. Further, both adjustments are issues concerning the proper normalization of contracts rather than contract updates. Based on the Company's response to data request ICNU 7.8 in UE 210, adjustments concerning the proper modeling of contracts are "fair game" even under the category of adjustments the Company proposes to exclude from the TAM in stand alone cases. If such adjustments are allowable in future stand alone cases, there is no reason they should not be allowed in this case.

Further, Mr. Duvall argues that the GP Camas adjustment is based on new discovery from Washington and represents a non-contract update. That statement is erroneous because I did not base my adjustment on any discovery response from the Washington case. When I asked about this in discovery, the Company stated that Mr. Duvall meant to refer to Wyoming discovery in his testimony. This again is incorrect. Rather, my adjustment (as was also the case for the Biomass adjustment) was based on data available to the Company since July, 2008 – the same data, used by the Company for various contract modeling assumptions. The remainder of Mr. Duvall's arguments concerning GP Camas amount to speculation or are irrelevant, and do not merit a response. Adjustments C.2.a and C.4.a on Table 1 present the updated Biomass and GP Camas adjustments.

Call Option Purchases

Q. WHY DOES MR. DUVALL OPPOSE IMPLEMENTATION OF CALL OPTION PURCHASE MODELING METHODS APPROVED BY THE COMMISSION IN UE 191?

A. Mr. Duvall contends the Commission never decided this adjustment was a good policy. In this instance, Mr. Duvall ignores the fact that the Company proposed this policy in UE 191, and other parties accepted it, in a fully litigated case – not a black box settlement. There was no reason for the Commission to address its policy basis. I find it ironic that Mr. Duvall considers the black box stipulation in UE 199, as having some precedential value as regards screens, but does not consider the UE 191 decision (decided by the OPUC) to have any value.

Mr. Duvall also contends that disallowing the call option premiums when options are "underwater" would be like disallowing insurance premiums except in years where claims were paid. This, however, is an invalid comparison because the Company both pays for insurance premiums and receives insurance payments on a regular basis. Ratepayers have the opportunity to benefit from the receipts and should therefore support the payments. For example, in the case of the long Hunter outage in 2001, insurance paid for part of the repairs. Customers paid for the insurance, and received the benefit of the repairs.

In the case of the call options, the Company is proposing to include costs in the test year, for which there is no expectation of offsetting benefit because normalized prices do not reflect such unexpected events. Indeed, Mr. Duvall testified on page 33 that these contracts were not expected to dispatch regularly. If actual market prices increase substantially above current forecasts, then the Company may benefit from the call options, but not the customers. Consequently, this is a "one sided" insurance policy where customers pay all of the costs, while the Company argues that no benefits exist under normalized conditions. In the end, only shareholders obtain benefits, but bear none of the costs. It would be a poor policy to allow such a practice to be permitted. The Commission disallowed these premiums in UE 191 and I recommend they continue to do so. Adjustment C.3.a presents the updated Morgan Stanley call option adjustment.

Transmission Modeling

Q. DOES MR. DUVALL AGREE WITH YOUR PROPOSED SHORT TERM FIRM ("STF") TRANSMISSION SYNCHRONIZATION ADJUSTMENT?

A. No. Mr. Duvall proposed to continue to use a four year average transfer capacity for STF transmission, but use the much higher costs from a single recent year (the 12 months ended June 30, 2008). He argues that some of the STF transmission costs included in the test year, such as ancillary services are not specifically related to the transactions whose capacity is modeled on a four year average basis. While I consider this to be a mismatch, Mr. Duvall argues that this is comparable to modeling a four year average outage rate for power plants, while using current fuel costs.

Mr. Duvall's second argument is specious. The physical transfer capacity and transaction volumes of the links modeled in GRID change substantially from year to year, and as a result, the associated cost will change. However, the amount of money the Company spends on fuel does not determine the size of the power plant using the fuel. Mr. Duvall has cause and effect backwards in his analogy. Assume for example, the case of a power plant expanded from 200 MW to 400 MW the third year in a four year period. Mr. Duvall's approach would be to use a recent single year of fuel costs for a 400 MW plant paired with a much lower four year average capacity of 300 MW.

I agree, however, that some of the STF transmission costs included in the test year may be related to ancillary services or other elements that are not directly related to transfer capacity or transaction volumes. Thus, I have eliminated those costs in wheeling expense and synchronize only the costs related to transfer capacity and transaction volumes. This reduces my original adjustment, and the updated amount is shown as Adjustment F.3a on Table 1.

Q. CAN YOU SHOW WHY THE COMPANY'S RECOMMENDATION IS FLAWED?

A. Yes. The figure below shows the problems with the Company's methodology. The costs and volumes of STF transmission have increased substantially in recent years. The Company uses a four year average transfer capacity, but GRID only uses part of that capacity. In the Company's 2010 test year, transfers are only [redacted] thousand MWH – a mere fraction of the four year average. However, the Company is including transaction related costs of at least [redacted] million based on the 12 months ended June 30, 2008. This results in an average transfer cost per MWH of [redacted]. The 2008 costs, for example, were [redacted] million supporting transfers of [redacted] million MWH, for an average cost of [redacted]/MWH. As a result, the Company includes the very high recent costs, but does not model the capacity associated with those costs, and only a fraction of the transfer volume.

To address this problem, I have identified the transaction related costs and modeled the cost of transfers based on volumes. This is exactly the manner in which Mr. Duvall stated STF modeling should be performed in the 2008 Utah case. Implementing this correction reduces the STF Synchronization adjustment by about $3 million.

[redacted]

Q. WHY DOES MR. DUVALL OPPOSE YOUR CAL ISO ADJUSTMENT?

A. Mr. Duvall makes a vague argument that the Company expects it will continue to do business with the Cal ISO, and therefore should include the associated costs. However, he does not identify any specific transactions associated with the Cal ISO that are included in the test year. In the past, the Company has stated it cannot identify Cal ISO charges by delivery point, but that Cal ISO charges are "mainly for SP 15."[11/]

Further, discovery also indicates, that the Cal ISO charges are related to transactions that the Company will enter into later on:

> The Cal ISO wheeling fees and service fees are not only determined by the short term firm transactions that the Company has currently entered into, but also based on transactions that the Company will enter into through the time of delivery to balance the system. Given the nature of system balancing activities, the volume of the transactions that could incur Cal ISO charges is expected to be similar to what the Company has experienced, so are the Cal ISO charges.

Exhibit ICNU/204, Falkenberg/1. Consequently, there is again a mismatch between the test year costs and the benefits produced from incurring those costs. Unless we assume the Company is imprudent (i.e., that it spends more than $11 million per year on Cal ISO fees, but expects no cost savings to occur from those expenditures) there should be an offset to these costs in 2010, or they will simply not be incurred. In either case, the test year is incorrect, and an adjustment should be made.

In the April filing, the Company did not have any SP 15 transactions modeled in GRID. Mr. Duvall proposes to model a link between Four Corners

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[11/] Exhibit ICNU/204 contains various discovery responses relevant to this issue.

and SP 15 in a subsequent update, but there is no recognition of the relationship between SP 15 transactions and Cal ISO cost levels. I recommend the Cal ISO fees be eliminated for this reason. As of the July update, there are still no SP 15 transactions included in the test year. This adjustment is unchanged from the July filing, and is shown as Adjustment F.1.a on Table 1.

Q. DO YOU HAVE ANY OTHER COMMENTS CONCERNING CAL ISO?

A. Yes. The Company includes substantial congestion charges for Cal ISO in June during the test year. This occurred because the Company uses June 2008 as the basis for the test year Cal ISO charges, and during that month, there were substantial congestion charges. ICNU/204. If the Commission does allow Cal ISO charges to be included in the test year, the congestion charges should be disallowed, because the Company has no expected transactions in Cal ISO in June 2010. It makes no sense to assume congestion charges will be incurred when the Company does not have any transactions scheduled. This adjustment would reduce Oregon NVPC by $355,000.

Q. ON PAGE 38, MR. DUVALL OPPOSES MODELING OF NON-FIRM TRANSMISSION BECAUSE IT IS UNCERTAIN, REDUCES NVPC, AND HE CONSIDERS IT TO BE "POOR REGULATORY POLICY." DO YOU AGREE?

A. No. I'll leave it to the OPUC to decide what good regulatory policy is. It's worth noting, however, that in Docket No. 07-035-93, the Utah Commission required the Company to begin the modeling of non-firm transmission and the Company did so in the next case it filed (Docket No. 08-035-38).

As for Mr. Duvall's arguments about uncertainty, there are very few inputs to GRID that are not subject to similar uncertainty. That's why multi-year averages are used for some inputs such as outage rates, or non-firm transmission. Normalization is intended to address uncertainty, by smoothing out annual variations. Mr. Duvall agrees that the Company uses this resource on a daily basis, so there is no reason to ignore it. Mr. Duvall has also testified that non-firm and short term firm transmission should be modeled on the same basis.[12/] Non-firm transmission is updated on Table 1 as Adjustment F.2.a.

Q. MR. DUVALL CONTENDS THE APS STF CONTRACT ADJUSTMENT F.4 IS UNECESSARY. DO YOU AGREE?

A. Yes. The Company conceded on August 14, 2009, that it had not provided accurate workpapers in its earlier filing.[13/] Upon finally being able to review the accurate workpapers, I have agreed to eliminate this part of the original F.4 adjustment. I also eliminate the portion related to the prior period adjustment based on information provided by the Company on the conference call. However, I retain the transmission imbalance adjustment in updated Adjustment F.4.a. This issue is already well developed in the record, and Mr. Duvall has not introduced any new arguments. It is interesting, however, that the wind integration charges proposed by the Company in this case and other states appear similar in concept to the transmission imbalance adjustment in that they are based on quantifying impacts of hour ahead forecast errors, similar to the way in which transmission balancing charges are incurred.

12/ Utah Docket No. 08-035-38 (Duvall Rebuttal, page 35 line 793).

13/ This resulted in two violations of the TAM Guidelines – not providing accurate workpapers, and not informing parties of an error in a timely manner.

Other NVPC Adjustments

Q. DOES MR. DUVALL STILL DISPUTE THE CHOLLA CAPACITY ADJUSTMENT?

A. Yes. Mr. Duvall contends the Cholla transmission limits are less than the capacity of the resources. However, this is irrelevant, since the plant historically has a high outage rate and the capacity available will exceed the transmission capacity only 19% of the time (which is already factored into my adjustments). Mr. Duvall also objects to the adjustment on the basis that such updates are not allowed under the TAM Guidelines. This is clearly erroneous, as the only limits posed by the TAM Guidelines are on the Company, not on the Commission or the parties. Further, this issue has been litigated since the Utah case in February of 2009. The Company knew about this issue well in advance of the TAM filing, belying any claim that it is an update. In reality, this adjustment is designed to correct an omission on the part of the Company, since the actual capacity available from Cholla is not limited by transmission to the degree to which the Company assumes. I do, however, eliminate the Gadsby 1 minimum capacity component from the updated Adjustment G.2.a, because of the new information provided in the Company's rebuttal.

Q. DO YOU AGREE WITH MR. DUVALL'S ARGUMENT CONCERING THE LONG HOLLOW WIND FARM INTEGRATION CHARGES?

A. No. The facts are uncontroverted: the Company includes costs related to providing wind integration services incurred by a third party wholesale wind farm, but does not charge the customer for that service under the OATT. This is a clear case of expecting retail customers to pay for uncompensated services provided to wholesale customers. Mr. Duvall indicates the Company has no current plans to file any request to amend the OATT to charge the customer causing the cost to pay for this service. While this is a minor issue in the present case, PacifiCorp has recently increased its wind integration cost estimate by a factor of six in other states. If the Company were to file its new integration costs in a future case, retail customers could be charged more than $2 million to provide wind integration services to wholesale customers. Adjustment G.3.a removes the Long Hollow wind integration charges. Based on discovery responses received late on August 24, 2009, it appears this adjustment should be expanded to include some of the wind integration charges applied to the Seattle City Light State line project as well.

Staff Adjustments

Q. WHAT IS ADJUSTMENT G.4.a?

A. I have reviewed the Staff testimony and believe their adjustments for the Tokotee and Boyle hydro plants energy and the coal price adjustments are reasonable and well supported. I have recomputed the Staff hydro adjustments based on the current forward price curves. I have removed my original Bridger coal adjustment because I support the Staff coal adjustment. Adjustment G.4.a provides the net effect of all these adjustments.

Planned Outage Modeling

Q. DO YOU AGREE WITH THE COMPANY'S CORRECTIONS TO THE PLANNED OUTAGE SCHEDULE?

A. In part. The Company did eliminate overlaps for the Bridger plant, which I agree with. The Company provided no counter arguments against my shift in the planned outage schedules for Hermiston or Colstrip, which was based on historical patterns. The Company also corrected an error in its Hermiston planned outage data. Mr. Duvall continues to support a fall outage of Colstrip, which is contrary to historical practice. Further, from 2009 to 2012, all forecasted Colstrip scheduled outages are planned for the spring.

Mr. Duvall's only substantive argument concerned the timing of the Currant Creek outage where he also assumes a fall outage. However, Confidential Exhibit ICNU/205 demonstrates that Currant Creek and Lake Side are expected to have nearly equal incidences of spring and fall outages in the period 2009-2012, based on data provided in response to ICNU data request 1.6. As a result, I believe scheduling one outage in the spring and the other in the fall is reasonable. Mr. Duvall's scheduling assumptions have nothing to do with the timing of either actual prior outages, or forecast future planned outage events, and should be rejected. Adjustment H.1.a presents the updated planned outage adjustment.

Q. PLEASE EXPLAIN ADJUSTMENTS H.3.a AND H.4.a.

A. This includes only an update for removal of the ramping adjustment for Bridger, due to lack of realistic data to develop this input. The Company indicated during the August 14, 2009 conference call that they did not understand the problems I cited with the Bridger ramping adjustment before, and that Mr. Duvall's testimony was premised on this misunderstanding. Further, despite promising to provide it, the Company has not provided any additional data to support the Bridger ramping adjustment. I do eliminate the ramping adjustment on other units. I originally proposed this adjustment be included as a load modifier, but the Company has not been able to prepare such a modification in this case. Finally, Adjustment H.4.a provides the updated value of the minimum loading and deration adjustment proposed in UM 1355.

<u>Objections to Updates and Corrections</u>

Q. DO YOU AGREE WITH ALL OF THE OTHER UPDATES AND CORRECTIONS FILED BY THE COMPANY?

A. No. There are a number of instances where the Company failed to provide support for their corrections, where the corrections were incorrect, or where adjustments were improperly characterized under the TAM Guidelines.

Q. DO YOU AGREE WITH UPDATE 8 – WIND ON PPL/205, PROFILES FOR MOUNTAIN WIND?

A. The adjustment is proper and incorporates one of my recommended adjustments. However, this is the correction of an error, not an update. It appears the Company is simply trying to conceal the fact that it neglected or ignored data showing reduced output from these projects that was in its possession since December 2008. There is no reason why the Company should not have included this in its original filing. This is quite important as it illustrates that the Company has violated the intent of the TAM Guidelines in this case and continues to abuse the TAM.

Q. DO YOU AGREE WITH CORRECTION 4 ON PPL/105?

A. In this adjustment, the Company reduced the Currant Creek and Lake Side normalized planned outage duration to reflect what was called the “engineer’s recommended” planned outages requirement. This input was overstated in the April filing. However, no documents were provided supporting either the new or original assumptions. While the Company agreed it could provide such information it has not done so. Under the TAM Guidelines, such documentation is required. Also troubling is the fact that in UE 191 the Company claimed to have used the "manufacturer's recommendations" for combined cycle planned outages, but used only seven outage days, though with some additional support.[14/] The Company should not be allowed to rely on vague, unsupported data, and TAM Guidelines require documentation of such input changes. Assuming the Company is allowed to model the Currant Creek outage in the fall, use of the assumptions approved in UE 191 produce an additional reduction to Total Company NVPC of $275,000 Total Company, or 25% of Correction 4. Under a spring schedule, the impact is not significant, however.

Q. DO YOU AGREE WITH CORRECTION 7 ON PPL/105?

A. No. In this instance the Company attempted to address a problem in GRID where the duct firing capability of Currant Creek was operating, even though the main plant was off line. I believe the Company failed to provide the workpapers actually used to develop the inputs for this correction, and I was unable to replicate their results. I was eventually able to discern what the Company did, and it is not a reasonable solution to this sort of problem. The Company discovered that the duct firing was running a few hours of January and December when the main plant was offline. To "fix" this problem, the Company forced the duct firing off line every day for a month for two hours. As there were many more days in the month when the problem did not occur (i.e., the Currant Creek was running) this was a crude and completely erroneous solution. The fact that it

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[14/] Re PacifiCorp, Docket No. UE 191, PPL/204 Widmer/38.

reduced NVPC indicates the Company was actually eliminating some of the uneconomic generation of duct firing along the way.

Q. WHAT IS YOUR RECOMMENDATION?

A. There is nothing to prevent either the uneconomic or improper operation of duct firing in the GRID model. The duct firing screening adjustments, I propose, will eliminate the problem based on a proper analysis of hourly data. I recommend the Commission also require the Company to make these adjustments to all subsequent updates to GRID. The Company's approach to this issue is clearly not intended to provide a reasonable correction to another problem it has acknowledged exists in GRID.

Q. DO YOU AGREE WITH CORRECTION 9 ON PPL/105?

A. No. In this instance, the Company is trying to characterize a thermal plant update (which is not allowed under the TAM Guidelines) as an error correction. The Chehalis start cost inputs originally filed by the Company were used in several cases in other states and have been supported as being consistent with the IRP assumptions. The Company now contends that it discovered these supported inputs were an error, and replaces them with different and completely unsupported inputs. It is not reasonable for the Company to attempt to provide itself with the opportunity to increase NVPC in violation of the TAM Guidelines by simply asserting new inputs are required and calling them corrections. This adjustment should be disallowed.

Q. DO YOU BELIEVE THE COMPANY HAS MADE ALL OF THE APPROPRIATE GRID CORRECTIONS?

A. No. The Company appears to have substantially overstated the cost for Huntington coal. It appears that the Company had a mistake in the tonnage assumptions for the plant, based on purchases from Sufco, a third party supplier. In the Company's workpapers, tonnage from Sufco offset the much lower cost tonnage from Deer Creek. This resulted in excessive costs as the deliveries from the Deer Creek mine were curtailed. The mechanics of this error are as yet unclear, but the Company's June Utah GRC did not show any Sufco deliveries in the months in question. The same was true of the Company UE 199 filing, and the December 2008 and February 2009 filings made by the Company in Utah Docket No. 08-035-38. The June 30, 2010 test year Huntington coal cost for the June 2009 Utah filing (Docket No. 09-035-23) for Huntington is quite close to the corrected coal cost figures I have computed. Correcting this error results in the adjustment shown on line I.1.a on Table 1.[15/]

Q. WHY DIDN'T ICNU RAISE THIS ISSUE EARLIER?

A. The error wasn't obvious from the Company's initial filing. However, when the Company made its June, 2009 filing in Utah Docket 09-035-23, it was apparent that there was a large difference between the Utah and Oregon coal prices ($9.3 million for the 6 months ended June 30, 2009, which were common to both test years, and $20.3 million on an annual basis). However, by that time it was too late to obtain the information in discovery (in either Utah or Oregon) in time to

[15/] Discovery is outstanding on this issue, and I may change my recommendation when discovery is complete. If the Sufco tonnage is not an error, then there are serious prudence questions regarding the Company's purchasing strategy. These costs should not be allowed because the Company has not submitted any evidence demonstrating the prudence of these higher costs.

include the issue in the July testimony. Once the additional discovery was available (namely, the Regulatory Fuel Budget Report for Utah), it was possible to determine the source of the difference in cost was the Sufco tonnage in the Oregon filing. This, coupled with the very high cost per ton figures for the Oregon test year, makes it fairly apparent that there was a problem in the data provided in this case.[16/] Note that the much lower Utah figures are consistent with information from prior cases, as well as actual Net Power Cost reports.

Q. PLEASE DESCRIBE EXHIBIT ICNU/206.

A. This exhibit is the analog to ICNU/108, reflecting the August update showing each component of my recommended adjustments.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

16/ Confidential Exhibit ICNU/207 is a copy of the pertinent pages from the fuel workpapers in the two cases illustrating the rather odd results for the Oregon test year.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

In the Matter of	)
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PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2010 Transition Adjustment Mechanism	)
	)

ICNU/201

Summary of Recommended Adjustments

Exhibit ICNU/201
Summary of Recommended Adjustments - $

	Total Company	Est. Oregon Jurisdiction	
		SE 25.00%	
		SG 26.88%	
I. GRID (Net Variable Power Cost Issues)			
PacifiCorp Request NPC	1,100,545,210	$272,967,396	
A. GRID Market Caps			
1 GRID Market Caps	(18,154,991)	(4,709,314)	
B. GRID Commitment Logic Error			
2 Correct Company Screens Currant Creek	(1,560,485)	(404,782)	
3 Correct Company Screens Gadsby Steam	(231,398)	(60,023)	
4 Lake Side Duct Firing Screening Adjustment	(557,405)	(144,588)	
5 Currant Creek Duct Firing Screening Adjustment	(436,508)	(113,228)	
6 ~~*Remove Ineligible O&M Costs*~~	~~*(1,970,498)*~~	~~*(511,137)*~~	A
7 Start Up Fuel Energy Value	(3,937,202)	(1,021,291)	
C. Long Term Contract Modling			
8 BHP	(1,203,630)	(312,216)	
9 PSCO	(1,101,796)	(285,800)	
10 UMPA II	(409,418)	(106,201)	
11 SMUD Shaping	(3,031,414)	(786,334)	
12 Biomass	(600,411)	(155,744)	
13 Morgan Stanley Call Options	(2,641,879)	(685,290)	
14 GP Camas	(808,782)	(209,794)	
D. Hydro Modeling			
15 Condit Hydro	(3,651,975)	(947,304)	
16 Bear River Normalization	(3,472,971)	(900,871)	
17 Hydro Reserve Input Parameter	(579,916)	(150,427)	
E. New Resource Modeling			
18 ~~*Chehalis Reserve Modeling*~~	~~*(197,920)*~~	~~*(51,339)*~~	A
19 ~~*Mountain Wind QF*~~	~~*(1,575,114)*~~	~~*(408,577)*~~	A
F. Transmission Modeling			
20 Cal ISO Fees	(11,175,680)	(2,898,916)	
21 Non Firm Transmission	(2,470,754)	(640,901)	
22 STF Transmission Link Test Year Synchronization	(8,151,766)	(2,114,527)	
23 ~~*Arizona Transmisson Pro-Forma Error*~~	~~*(207,900)*~~	~~*(53,928)*~~	E
24 Transmission Imbalance	(841,253)	(218,217)	
25 ~~*Prior Period Adjustment*~~	~~*(260,744)*~~	~~*(67,636)*~~	E
G. Other NVPC Adjustments			
26 ~~*Regulating Margin*~~	~~*(3,081,757)*~~	~~*(799,392)*~~	A
~~*27 Gadsby 1 Minimum Capacity Rating*~~	~~*(48,701)*~~	~~*(12,633)*~~	E
28 Cholla Capacity Upgrade	(608,801)	(157,920)	
29 No Adjustment			
30 Long Hollow Wind	(383,454)	(99,466)	
31 ~~*SCL Stateline Reserve Capacity*~~	~~*(1,648,662)*~~	~~*(427,655)*~~	A
32 Bridger Coal EITF No. 04-6	(12,415,437)	(3,220,502)	
H. UM 1355 and Other Outage Rate Modeling Issues			
33 Planned Outage Schedule	(2,488,797)	(645,582)	
34 ~~*Outage Rate WE WD*~~	~~*(1,334,547)*~~	~~*(346,175)*~~	A
35 Bridger Ramping	(575,219)	(149,209)	
36 ~~*Ramping other Units*~~	~~*(1,517,615)*~~	~~*(393,662)*~~	E
37 Minimum Loading and Deration	(4,170,652)	(1,081,846)	
38 ~~*Currant Creek and Lake Side EFOR*~~	~~*(2,424,940)*~~	~~*(629,017)*~~	A
39 ~~*Gadsby EFORd*~~	~~*(137,193)*~~	~~*(35,587)*~~	A
40 ~~*Long Outages*~~	~~*(520,896)*~~	~~*(135,118)*~~	A
~~*41 Combined Cycle Planned Outage Deration Error*~~	~~*(460,431)*~~	~~*(119,434)*~~	E
I. COMPANY CORRECTIONS			
42 ~~*Other Unverified GRID Errors*~~	~~*(4,539,569)*~~	~~*(1,177,541)*~~	A
Subtotal NPC Baseline Adjustments -	(105,588,484)	(27,389,125)	
Allowed - Final GRID Result*	994,956,725	245,578,271	

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

In the Matter of	)
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PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2010 Transition Adjustment Mechanism	)
	)

ICNU/202

PacifiCorp Data Responses from
Utah Docket No. 08-035-38

CCS Data Request 30.7

NPC GRID: Please identify all changes in the physical characteristics, engineering or operational constraints (i.e. minimum stream flow requirements) etc that had the effect of lowering the annual energy output of the Bear River hydro resources after 2007.

Response to CCS Data Request 30.7

No significant changes to the physical characteristics, engineering or operational constraints.

CCS Data Request 30.6

NPC GRID: Please identify all changes in the physical characteristics, engineering or operational constraints (i.e. minimum stream flow requirements) etc that had the effect of lowering the annual energy output of the Bear River hydro resources from 2008 to 2009.

Response to CCS Data Request 30.6

No significant changes to the physical characteristics, engineering or operational constraints.

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In the Matter of	)
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PACIFIC POWER & LIGHT	)
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ICNU/203

PacifiCorp Data Responses from
Wyoming Docket No. 20000-266-EP-07

20000-266-EP-07/Rocky Mountain Power
March 5, 2007
WIEC 1st Set Data Request 1.6

WIEC Data Request 1.6

Explain why some parts of the SMUD contract are priced at market. Explain why the Company has decided on this treatment. To the extent this rests on precedent, provide citations to pertinent orders.

Response to WIEC Data Request 1.6

Pursuant to the Company's contract with SMUD, they have the right to take up to 219,000 MWh of Provisional Firm Energy per year. If SMUD takes Provisional Firm Energy, they are required to return an equal volume to the Company by December 31 of each year.

For rate-making purposes, the Company has always excluded the Provisional Firm Energy sale and purchase because (1) it is not a fixed obligation like the Firm Energy sale, and (2) the volumes are offset on an annual basis.

A copy of the SMUD contract is provided as Attachment WIEC 1.6 on the enclosed CD.

Resource	Version Name	Attribute	Priority	Start Date	All Times	Value
SMUD Provisional	SMUD Provisional return	Dispatch Type				SMUD Provisional
SMUD Provisional	SMUD Provisional return	Energy Direction				Purchase
SMUD Provisional	SMUD Provisional return	Inception Date				'06/10/1987
SMUD Provisional	SMUD Provisional return	Time Period				Hourly
SMUD Provisional	SMUD Provisional return	Block Period				Unset Value
SMUD Provisional	SMUD Provisional return	Option Type				Put Option
SMUD Provisional	SMUD Provisional return	Pricing Archetype				Fixed Price
SMUD Provisional	SMUD Provisional return	Season End Date				'January 1
SMUD Provisional	SMUD Provisional return	Season Start Date				'January 1
SMUD Provisional	SMUD Provisional return	Shaping Type				Price Shaping
SMUD Provisional	SMUD Provisional return	Termination Date				'01/01/2015
SMUD Provisional	SMUD Provisional return	MAX ANNUAL TAKE (MWH	0		Y	219000
SMUD Provisional	**SMUD Provisional return**	**RESTRICTED**	**0**		**Y**	**1**

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

In the Matter of	)
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PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
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2010 Transition Adjustment Mechanism	)
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ICNU/204

PacifiCorp Data Responses from
Wyoming Docket No. 20000-333-ER-08

WIEC Data Request 11.6

Provide justification for PacifiCorp's assumption to base test year Cal ISO wheeling fees and service fees on 2007 fees, when test year volume of STF wholesale sales and purchase transactions are forecast to be significantly lower than the volumes experienced for 2007.

Response to WIEC Data Request 11.6

The Cal ISO wheeling fees and service fees are not only determined by the short term firm transactions that the Company has currently entered into, but also based on transactions that the Company will enter into through the time of delivery to balance the system. Given the nature of the system balancing activities, the volume of the transactions that could incur Cal ISO charges is expected to be similar to what the Company has experienced, so are the Cal ISO charges.

WIEC Data Request 1.27

WIEC understands that wholesale transactions that would utilize the CalISO system would incur fees unless they are booked out. And, that since megawatt-hours not specific to certain wholesale transactions at a particular market hub are booked out, PacifiCorp cannot specifically identify which wholesale transactions actually incurred Cal ISO fees after the fact. Is this understanding correct?

Response to WIEC Data Request 1.27

PacifiCorp believes that WIEC's understanding is correct. However, a clarifying example follows. The first sentence of this request might be better written, "Wholesale transactions occurring in Cal ISO markets of SP-15 and NP-15 incur fees when and if they use the Cal ISO transmission system and are not booked out at the market hub."

Take, for example, an hour when PacifiCorp is buying four blocks of 25 MW in SP-15, and simultaneously selling two blocks of 25 MW at the same hub. Because there are both purchases and sales, 50 MW of purchases can be "booked out" with the 50 MW of sales. The remaining 50 MW of supply would be transferred out of the Cal ISO. It is that transfer which, because it uses the Cal ISO transmission system, incurs fees. It would be arbitrary (and in practice, unnecessary) to identify exactly which 50 MW of the 100 MW purchased was transferred and which 50 MW was booked out. Because it is *transmission use* that incurs fees, and not *transactions,* PacifiCorp's statement that it "cannot specifically identify" which transactions incurred fees is correct.

WIEC Data Request 11.14

Filed net power costs show that PacifiCorp sold 571,800 MWh short at SP-15 for the test year. Explain what the trading strategy was for these transactions and whether PacifiCorp covered that short position? If yes, provide a summary of those purchases in the same format as Exhibit 8 from Wyoming Docket No. 20000-315-EP-08.

Response to WIEC Data Request 11.14

Sales at SP 15 are made to hedge the Company's financial exposure at Four Corners. This occurs when the Company has a desire to hedge its financial exposure at Four Corners. At a time closer to delivery when the Four Corners market becomes more liquid, the Company would sell at Four Corners and, if the hedges were physical products, buy at SP 15. Alternatively, the Company may wheel the power from Four Corners to SP 15 to close the SP 15 physical position in the hour-ahead market if transmission is available and it is more economical to do so. The SP-15 positions were covered. The short positions at SP 15 have not been covered at this point because those short portions are for the 12-month period ending November 2009; these positions will be covered when the liquidity at Four Corners increases closer to the time of delivery..

WIEC Data Request 4.17

In reference to WIEC 1.26, PacifiCorp stated it does not agree with WIEC's interpretation. However, after reading Mr. Duvall's Errata testimony WIEC still believes its interpretation is correct. Explain in detail how PacifiCorp would incur CalISO fees if no wheeling occurs between Four Corners and SP-15 and short sales at SP-15 are covered by purchases at SP-15.

Response to WIEC Data Request 4.17

As indicated in Company's responses to WIEC Data Request 1.9 and WIEC Data Request 1.10, transactions that may have incurred CAL ISO wheeling and service fees are noted by a Point of Delivery/Receipt of "SP15" or "NP15" and with the counterparty of Cal ISO. That is, the transfer between Four Corners and SP-15 is not the only path that could incur Cal ISO fees.

20000-333-ER-08/Rocky Mountain Power
January 21, 2009
WIEC 18th Set Data Request 18.2

WIEC Data Request 18.2

Provide an explanation and justification for the abnormally high level of Cal ISO expenses shown on Attachment WIEC 11.2 for the months of May, June and July 2008.

Response to WIEC Data Request 18.2

The cause of the higher expenses was due to "congestion" charge types 206 (on day-ahead transactions) and 256 (on hour-ahead transactions). Congestion occurs when there is demand on a transmission path above its capacity. In order to allocate the transmission capacity fairly, the CAISO effectively auctions those rights to those parties willing to pay additional charges to use the path – the Congestion charges. PacifiCorp at times is willing to pay congestion in order to ensure it gets allocated the transmission it needs.

When PacifiCorp is using CAISO transmission to move energy to its load, it is often prudent to pay these additional charges to ensure delivery. Often the only alternative would be to transact in markets where the cost of energy plus transmission exceeds the cost of energy plus wheeling plus congestion using CAISO transmission. That is the case for CAISO transmission used in May, June and July 2008.

Randy,

Here are what I found out:

Cal ISO charges are mainly for SP15. Charges for going into and out of Cal ISO are relatively small.

STF wheeling charges are for making short term wholesale transactions for the purpose of balancing the system.

The DC Intertie wheeling charges for transfer at NOB is because the Company takes delivery at the delivery point of Nevada Oregon Border on the DC intertie and transfer the power north to the service territory.

The payments to "Nevada" and "New Mexico" are payments to Nevada Power Company and Public Service Company of New Mexico, who own transmission assets that are not just within the borders of the states. We pay for using their facilities to transfer power from sources to requriements.

Do these answer your questions?

From: ConsultRFI@aol.com [mailto:ConsultRFI@aol.com]
Sent: Friday, April 11, 2008 9:41 AM
To: Taylor, Dave; Shu, Hui; Portouw, Jim {Mkt Affiliate}
Cc: CMURRAY@utah.gov
Subject: Re: Discussion on CCS SR 21.5

Dave,

Thanks for arranging this call, it was helpful in clearing some things up, though there were a few items left.

In thinking a little more about our discussion, I'd like to suggest the Company consider providing a supplemental answer to 21.5. In some cases, Hui indicated she was not certain of the answers provided, and was planning on checking some things. Hui also indicated that she was going a little beyond her area in addressing these matters.

For example, In the case of the Cal ISO charges the answer provided in 21.5 now seems potentially misleading, since it refers to transfers between links not modeled in GRID. If the correct answer is that it related to transactions internal to SP15 (or SP15 and COB), it would be better for everyone if that was changed.

Also, some of the items we discussed were related to STF wheeling charges. Hui indicated she thought these related to short term purchases of transmission service. However, as currently stated, the answer implies they are related to "short term purchases and sales" which could imply ST power transactions, as opposed purely to ST transmission services.

Finally, providing a revised answer would give the opportunity to check on the outstanding items, such as the Nevada, New Mexico, etc issues, and whether these related to transactions in those states, or otherwise.

Please consider whether the Company agrees a revised answer is necessary, and let me know.

In a message dated 4/10/2008 1:48:45 P.M. Eastern Daylight Time, Dave.Taylor@PacifiCorp.com writes:
When: Friday, April 11, 2008 9:30 AM-10:00 AM (GMT-07:00) Mountain Time (US & Canada).
Where: Phone
~~*~*~*~*~*~*~*~*

Randy Falkenberg
RFi Consulting, Inc.
PMB 362
8343 Roswell Rd.
Sandy Springs, GA 30350
770-379-0505 p

Privileged and Confidential - Prepared at Request of Counsel

ICNU Data Request 7.1

As part of the discovery in the current Utah proceeding, there was a conference call between Company representatives and Mr. Falkenberg in April of 2008. In that conference call, the Utah analog to the answer to ICNU DR 3.12 was discussed. Subsequently, an email was provided by the Company regarding certain related matters. In this email, Dr. Shu indicated that Cal ISO wheeling charges were "mainly for SP 15."

a. Please explain if this conclusion is still valid.
b. Please explain and/or provide the basis for the conclusion that Cal ISO wheeling charges are "mainly for SP 15." If supporting documentation exists that help quantify this conclusion, please provide.
c. Please explain the reasons for any changes to this conclusion and any supporting documentation.

Response to ICNU Data Request 7.1

a. The conclusion is still valid.

b. The conclusion is primarily based on the Company's experience on the proportion of transactions transacted in the SP15 area. Please refer to the Company's response to ICNU Data Request 7.2 for further discussion.

c. Please refer to the Company's response to subpart a. above.

PREPARER: Hui Shu

SPONSOR: Hui Shu

ICNU Data Request 7.2

Please provide an estimate and supporting documentation of how much of the Cal ISO wheeling expense included in the test year are for costs related to SP 15. To the extent the Company is unable to provide an estimate, please describe a process or procedure and data ICNU could use to develop such an estimate of how much of the Cal ISO wheeling expense included in the tesy year are for costs related to SP 15, and provide the necessary data.

Response to ICNU Data Request 7.2

Cal ISO charges by delivery points are not available. Please refer to Attachment ICNU 7.2, which provides a copy of the Cal ISO Settlement Guide for wheeling charges.

For a description of various other charges, please refer to the Cal ISO web site at: http://www.caiso.com/clientserv/settlements/SettlementsGuide/index.html.

PREPARER: Hui Shu

SPONSOR: Hui Shu

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2010 Transition Adjustment Mechanism	)
	)

ICNU/205

Currant Creek and Lake Side Planned Outage 2009-2012

Redacted Version

Currant Creek and Lake Side Planned Outage 2009-2012 ICNU 1.6

[redacted]

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
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ICNU/206

Summary of Recommended Adjustments

August Update

Exhibit ICNU/206
Summary of Recommended Adjustments - $

August Update	Total Company		Est. Oregon Jurisdiction	August TABLE 1
		SE	25.00%	
		SG	26.88%	
I. GRID (Net Variable Power Cost Issues)				Designation
PacifiCorp Request NPC	1,095,399,869		$272,397,235	
A. GRID Market Caps				
1 GRID Market Caps	(9,874,705)		(2,561,449)	A.1a
B. GRID Commitment Logic Error				
2 Reverse Company Screens	527,113		136,730	B.1a
3 Correct Combined Cycle Screens	(1,462,881)		(379,464)	B.1a
4 Side Duct Firing Screening Adjustment	(439,393)		(113,976)	B.1a
5 Gadsby Screens	(816,663)		(211,838)	B.1a
6 Change in Number of Comb Cycle Starts	(1,385,031)		(359,270)	B.2a
7 Start Up Fuel Energy Value	(5,461,541)		(1,416,697)	B.3a
C. Long Term Contract Modling				
8 BHP	(571,245)		(148,178)	C.1a
9 PSCO	(863,111)		(223,887)	C.1a
10 UMPA II	(216,925)		(56,269)	C.1a
11 SMUD Shaping	(2,727,254)		(707,436)	C.1a
12 Biomass	(654,987)		(169,900)	C.2a
13 Morgan Stanley Call Options	(3,057,000)		(792,971)	C.3a
14 GP Camas	(895,753)		(232,354)	C.4a
D. Hydro Modeling				
15 Condit Hydro	(701,199)		(181,888)	D.1a
16 Bear River Normalization	(3,457,411)		(896,835)	D.1a
17 Hydro Reserve Input Parameter	(422,885)		(109,694)	D.1a
E. New Resource Modeling				
18 Reverse PPL/105 Correction 9 Chehalis Start Costs	(1,556,321)		(403,702)	E.1a
F. Transmission Modeling				
19 Cal ISO Fees	(11,175,680)		(2,898,916)	F.1a
20 Non Firm Transmission	(1,009,227)		(261,788)	F.2a
21 STF Transmission Link Test Year Synchronization	(5,231,991)		(1,357,152)	F.3a
22 Transmission Imbalance	(860,240)		(223,142)	F.4a
G. Other NVPC Adjustments				
23 Cholla Capacity Upgrade	(518,472)		(134,489)	G.2a
24 Long Hollow Wind	(383,454)		(99,466)	G.3a
25 Staff Coal and Other Hydro Adjustments	(24,046,241)		(6,237,475)	G.4
H. UM 1355 and Other Outage Rate Modeling Issues				
26 Planned Outage Schedule	(2,989,301)		(775,410)	H.1a
27 Bridger Ramping	(545,865)		(141,595)	H.3a
28 Minimum Loading and Deration	(4,517,880)		(1,171,915)	H.4a
I. Other Corrections				
29 Huntington Coal Error	(19,290,071)		(5,003,748)	I.1a
Subtotal NPC Baseline Adjustments -	(104,605,615)		(27,134,174)	
Allowed - Final GRID Result*	990,794,254		245,263,061	

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2010 Transition Adjustment Mechanism	)
	)

ICNU/207

REDACTED VERSION

[redacted]

[redacted]