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June 23, 2008

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 2009 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service
Docket No. UE 199

Dear Filing Center:

Enclosed please find an original and five copies of the Confidential Testimony and Exhibits of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities ("ICNU") in the above-referenced docket. The confidential pages and exhibits are inserted in separate envelopes and sealed pursuant to the protective order in this proceeding. Also enclosed is a complete Redacted Version of the testimony.

Thank you for your assistance.

Sincerely yours,

/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 Confidential Testimony and Exhibits of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities upon the parties, on the official service list shown below for UE 199, via U.S. Mail. A Redacted Version of the testimony and exhibits was served via electronic mail.

Dated at Portland, Oregon, this 23rd day of June, 2008.

/s/ Brendan E. Levenick
Brendan E. Levenick

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 199

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
TAM 2009	)
	)

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

June 23, 2008

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350.

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

A. I am a utility regulatory consultant and President of RFI Consulting, Inc. ("RFI"). I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Q. WHAT CONSULTING SERVICES ARE PROVIDED BY RFI?

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

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in Exhibit ICNU/101. I have participated in and filed testimony in numerous cases involving PacifiCorp net power cost issues over the past ten years.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses PacifiCorp's Generation and Regulation Initiatives Decision ("GRID") model study of normalized Net Variable Power Costs ("NVPC") for the projected test period, January 1 through December 31, 2009.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have identified and quantified 19 adjustments to the Company's GRID study summarized in more detail below and in Table 1 shown later in this testimony.

NVPC In Rates Adjustment

1. I recommend a reduction to the Company's request to reflect the impact of sales growth on NVPC recovered in rates. The Company proposes to include sales growth in GRID, but does not reflect the sales growth in billing units used for the TAM. Eliminating this mismatch produces a reduction to Oregon revenue requirements of $12.6 million.

Net Variable Power Costs (GRID)

2. PacifiCorp's request for $1,129.1 million in (total Company) NVPC is overstated by $55.7 million. I recommend NVPC of $1073.4 million, resulting in a reduction to Oregon allocated NVPC of $12.8 million. This amount still exceeds the Company's budget for 2009 by approximately [redacted].

GRID Commitment Logic (Uneconomic Operation)

3. Although GRID is intended to simulate the least cost operation of the PacifiCorp system, it fails to do so. GRID makes unit commitment (start up and shut down) decisions ignoring transmission and market capacity limits. In contrast, the subsequent dispatch of units in the Linear Programming ("LP") module recognizes these constraints. As a result, GRID commits units to make undeliverable sales, increasing NVPC. In the current Utah case, the Company finally admitted that corrections are required in the GRID model to solve this problem.

4. The Company has tried a variety of ad-hoc remedies to address this problem. These include logic changes, data adjustments, and acceptance of a variety of rate case adjustments. However, the GRID model still manifests the same problem, even after the Company's various corrections. Unfortunately, the Company continues to address the symptoms of this problem rather than the cause. When confronted with the very same issue in UE 149, PGE agreed to modify the Monet model to correct the problem.

5. I present a comprehensive interim solution to this problem. My proposed solution is to systematically de-commit resources during periods of uneconomic generation. These adjustments impact the Lakeside and Currant Creek units. Table 1 presents the results of these adjustments.

Long Term Firm ("LTF") and Short Term Firm ("STF") Contract Adjustments

6. In UE 191, the Company proposed to remove demand charges from call option contracts when they are not dispatched in GRID and the Commission adopted this adjustment. However, the Company has failed to make this adjustment in this proceeding. I recommend the Oregon Public Utility Commission ("Commission") apply this adjustment to the Morgan Stanley call option contract, P272158, reducing NVPC by the amount shown in Table 1.

7. The Company overstates the losses resulting from the wheeling of Hermiston generation over the BPA network. The value of this adjustment is presented in Table 1.

8. The Company incorrectly models the Sacramento Municipal Utility District ("SMUD") contract. The Company assumes SMUD will take power during only the highest cost hours of the year and in so doing, ignores the historical pattern of delivery. Correcting this problem results in the adjustment in Table 1.

9. I propose indexing the imputed price of the SMUD contract to the actual contract price. Unless this adjustment is made, the Company will not fully return to ratepayers the $98 million up-front payment it received for this below market contract. This adjustment is shown in Table 1.

10. The Company incorrectly models the Black Hills Power ("BHP") contract. The Company assumes BHP will take power primarily at high cost hours and use very little power during off-peak hours. Review of the actual contract delivery patterns shows BHP uses this contract as a baseload, rather than peaking, resource. The value of this adjustment is shown in Table 1.

11. In each of the past three years the Company has agreed to a non-generation agreement with the Biomass project. I include this adjustment in Table 1 with the expectation it would be replaced by the actual agreement, if an agreement is reached.

Planned Outage Schedule

12. The planned outage schedule used in GRID is based on arbitrary and unrealistic assumptions. Unit outages are scheduled in higher cost periods in the late winter and early fall in GRID, rather than predominately in lower cost periods in the spring. This is contrary to actual practice. The Company makes no effort in GRID to align planned outages to periods of low market prices, or to actual practice.

13. I propose to use the composite result from the four actual planned outage schedules for the period 2003-2007 in GRID. Use of these actual planned outage schedules reduces NVPC by the amount shown in Table 1.

Hydro Modeling

14. The Company's hydro modeling methodology uses three scenarios representing Wet, Median, and Dry hydro conditions. However, the Company greatly overstates the likelihood of the Wet and Dry hydro scenarios. The wet and dry scenarios should not be weighted the same as the median case. As a simplifying solution for the TAM, use of the Company's median hydro scenario only is preferable.[1/] To resolve this issue, I recommend the Commission require the Company to produce a full forty water year GRID study in its next TAM or general rate case. The value of this adjustment is shown in Table 1.

Forced Outage Rate Modeling

15. For several years, the Company computed outage rates for new resources based on a blend of historical data and IRP assumed outage rates. It did not do so in this case. Rather the Company used only a limited number of months of historic data to compute outage rates for Currant Creek and Lakeside.

16. The Company has an error in its application of the weekend, weekday outage rate split. The (higher) weekend outage rate should be applied for only a 48 hour weekend period. The Company inappropriately applies the weekend outage rate for a 56 hour period.

17. The Company proposes to include an adjustment for ramping of generators after shutdowns. This adjustment is not industry standard practice and was recently rejected by the Washington Utilities and Transportation Commission. Further, the Company admitted in the current Utah case that its ramping calculation was incorrect. Ramping was not used in UE 170 or UE 191, and owing to the settlement in UE 179, there is no precedent for its use in Oregon.

18. The Company computes outage rates for GRID based on actual outages for the 48 months ended June 30, 2007. However, the Company proposes to model monthly variations in unplanned generator outage rates based on four years of historical data. This approach is contrary to standard industry practice and is

[1/] This is an approach recommended by the Company in Utah PSC Docket No. 04-035-42.

unsupported on any statistical or engineering basis. Reversing this data change increases NVPC by the amount shown in Table 1.

19. I recommend that the Company be required to include all deferrable maintenance outages in the weekend outage rate. This was the practice used by the Company in its last full general rate case (UE 179) and it is standard industry practice. While all deferrable maintenance does not necessarily occur in the weekend, it can be scheduled to occur at comparable low cost times.

20. The value of all outage rate related adjustments is shown in Table 1. I present two adjustments. The first adjustment corrects the outage rates only for errors in the Company's calculations. The second adjustment provides for enhanced modeling of outage rates in GRID.

Generating Unit Representation in GRID

21. GRID derates maximum generator capacities to reflect unplanned outages. While this is an industry standard technique, the Company must also derate unit minimum capacities, and make an adjustment to heat rates to properly model the impact of unit outages on generator cost and performance. This approach is used by PGE in its Monet model, which has been accepted by the Commission for many years. The value of this adjustment is shown in Table 1.

Non-Firm Transmission

22. The Company excludes non-firm transmission from GRID. For this reason, GRID modeling results may differ substantially from actual results. While the Company argues that non-firm transmission is not "known and measurable" it is no different from many other aspects of system operation (such as unplanned outages) which the Company does model in GRID. I include non-firm transmission based on its average cost and availability over the most recent four-year period. The amount of this adjustment is shown in Table 1.

23. If the Commission does not include non-firm transmission in GRID, it should remove the SP15 transmission area and associated wheeling fees from the model. There are no firm interconnections between SP15 and the rest of the PacifiCorp system. Removal of SP15 and associated wheeling charges is consistent with modeling the system without non-firm transmission.

Other NVPC Adjustments

24. The Company has overstated wind integration costs. The Company incorrectly applied a formula from the IRP basing the wind integration costs on 2000 MW of installed wind capacity, rather than Test Year levels of less than 1300 MW. Further, GRID already includes similar wind integration costs from the IRP. The IRP data was not intended to be applied to 2009. Correcting these problems results in the adjustment shown in Table 1.

25. The Company has ignored the benefit of transmission imbalance charges it collects, which provides a source of below market energy. This adjustment is shown in Table 1.

26. I recommend a reduction to Cal ISO wheeling charges as the Company has overstated these costs and used a different method to compute these charges used for other wheeling contracts. This adjustment is shown in Table 1.

27. I recommend Minimum Filing Requirements ("MFRs") be adopted by the Commission for future TAM and general rate cases. I provide my recommended MFRs. I also recommend the Company be required to make arrangements with the attorneys and experts of parties prior to the filing so that they may obtain access to confidential information in the MFRs.

Table 1
Summary of Recommended Adjustments
$1000

	Total Company	Est. Oregon Jurisdiction
		SE 25.525%
		SG 26.411%
I. GRID (Net Variable Power Cost Issues)		
PacifiCorp Request NPC	1,129,101,025	$288,582,416
A. GRID Commitment Logic		
	-	-
1 Uneconomic Currant Creek Operation	(10,382,742)	(2,696,190)
2 Uneconomic Lakeside Operation	(5,158,062)	(1,339,446)
B. STF and LTF Contract Adjustments		
3 Call Options	<u>(505,000)</u>	(131,138)
4 Hermiston Loss Adjustment	(1,156,324)	(300,274)
5 Proper SMUD Normalization	(2,439,653)	(633,529)
6 Black Hills Contract Shape	(2,466,059)	(640,386)
7 SMUD Contract Index Pricing	(1,808,058)	(469,516)
8 Biomass Non Gen Agreement - Placeholder	(457,702)	(118,856)
C. Planned Outage Schedule		
9 Planned Outage Schedule	(4,983,663)	(1,294,158)
D. Hydro Modeling		
10 Median Hydro	(2,258,393)	(586,459)
E. Outage Rate Modeling		
11 Outage Rate Error Corrections	(4,256,334)	(1,105,285)
12 Outage Rate Modeling Enhancements	(2,570,235)	(667,439)
F. Generating Unit Representation in GRID	0	0
13 PGE Derate Modeling Method	(6,239,691)	(1,620,323)
H. Other NVPC Adjustments	0	0
14 Wind Integration Charges	(2,513,642)	(652,742)
15 Non Firm Transmission	(2,504,376)	(650,336)
16 Cal ISO Wheeling Fee	(2,934,048)	(761,913)
17 Transmission Imbalance	(3,071,592)	(797,631)
Alt. 18 Remove SP 15 (Alternate to Non Firm)*	(6,426,267) *	(1,668,773)
Subtotal Power Cost Adjustments -	<u>(55,705,572)</u>	<u>(12,796,850)</u>
Allowed - Final GRID Result*	1,073,395,453	275,785,566
Non-NVPC Adjustments		
19 NPC In Rates Adjustment		<u>(12,565,970)</u>

Q. DO YOU HAVE ANY INFORMATION TO HELP ESTABLISH THE OVERALL REASONABLENESS OF YOUR RECOMMENDED 2009 NVPC?

A. Yes. In ICNU data request ("DR") 4.26, I requested the Company's NVPC budget for 2009. The figure provided was [redacted] million less than the NVPC requested by the Company in this case, and roughly [redacted] million less than my normalized NVPC. Certainly, there are reasons why normalized power costs may differ from budget. For example, the Company likely budgets for the SMUD contract at its actual contract price, while it includes it in the test year at the imputed price. Further, budgets sometimes embody corporate goals to spur performance, such as improvements in plant reliability, increased efficiency, etc. I do not know if this is applicable in this instance, however, because the Company refused to provide any information explaining the difference between the budget and test year figures. However, the budget should represent a reasonable, achievable forecast for the Company. Otherwise, it would be of little value and would quickly be dismissed by employees as a meaningless expectation. Further, budgets may also be used in providing financial guidance, so clearly it must have a credible basis.

Q. DID THE COMPANY PROVIDE ANY EXPLANATION AS TO THE DIFFERENCE BETWEEN THE NVPC BUDGET FOR 2009 AND THE TEST YEAR FIGURES IN GRID?

A. No. In the response to ICNU DR 6.6, the Company indicated that because of the changes in market conditions now existing, the budget, which was prepared in November 2007 was now believed to be too low. ICNU/115, Falkenberg/1. This response seems questionable. In the recent Utah case the Company provided runs that updated the fuel costs and forward curves used in GRID, with a net effect of less than $7 million total Company for a 2008 test year. Thus, it seems rather unrealistic to believe that changes in power costs would be that substantial. To the extent that new forward prices and other factors have changed, I presume these will be factored into the Company's updates filed later in this case.

Finally, the Utah rate case filed in December 2007 was prepared around the same time as the Company budget and used a similar forward curve. The mid-2009 Utah test year showed NVPC results some [redacted] million higher than the CY 2009 budget. There is little reason to doubt that a December 2009 test year (prepared in November 2007) would not have been higher than the mid-2009 test year, and comparable to the current filing.[2/] As a result, it appears that the Company has greatly overstated power costs relative to the Company budget. In any case, the Company has refused to provide any explanation of these differences. The Commission should be concerned about the NVPC assumptions and modeling in the Company's TAM filings based on these unexplained discrepancies and the Company's refusal to explain them.

II. NVPC IN RATES ADJUSTMENT

Q. HAS THE COMPANY USED THE SAME LEVEL OF SYSTEM MWH TO COMPUTE NET VARIABLE POWER COSTS IN GRID IN THIS CASE AS IT DID IN UE 191 AND UE 179?

A. No. The Company has substantially increased NVPC at a system level to recognize the increase in sales occurring across the system. While much of the increase in loads is occurring in other states, between 2007 (the UE 179 test year) and this case, Oregon sales have increased by 78 MW on average, or more than 5%. Increases in load are ultimately the main driver of increases to net power costs.

[2/] The Company requested $1.051 billion for a 2008 test year, compared to $1.092 billion for the mid 2009 test year. Simple extrapolation would suggest a figure of $1.140 billion for a 2009 test year had one been prepared at that time. This is comparable to the figures used in the current case.

Q. DOES THE COMPANY RECOGNIZE THESE INCREASED SALES IN COMPUTING THE TAM ADJUSTMENT FOR 2009?

A. No. The Company proposes to perpetuate a mismatch between the billing units used to compute the TAM adjustment and the MWh loads reflected in GRID. The Company continues to use forecast billing units from UE 179 (the 2007 test projected test year) in developing the TAM rates. Thus, the Company proposes to charge customers for the higher costs created by load increases, but it is unwilling to reflect the higher revenues that accompany those increases. This is patently unfair, and contrary to any accepted ratemaking technique.

Q. HOW MUCH REVENUE DOES THE COMPANY COLLECT UNDER SCHEDULE 200 FOR RECOVERY OF NVPC?

A. In UE 191 the Company was allowed to recover NVPC in rates from Oregon customers of $247 million. The TAM increase for that case was based on the 2007 test year billing units. Reflecting the 5% Oregon sales growth embedded the 2009 GRID test year results in additional revenue to the Company of more than $12 million on an Oregon basis. I recommend the OPUC eliminate the mismatch between MWh used in computing the TAM rates and those used in computing NVPC by imputing this additional revenue as a credit to the test year. This adjustment is shown in Table 1.

Q. HAS THE COMPANY ATTEMPTED TO JUSTIFY THIS MISMATCH BETWEEN SALES REVENUES AND COSTS IN GRID?

A. In the response to ICNU DR 6.1, the Company states that it didn’t believe it was appropriate to change billing units outside of the context of a full rate case. ICNU/115, Falkenberg/2. This argument may have merit if the Company took the same view as regards the loads used in the TAM. However, the Company does not. It wishes to gain the *advantage* of recovery of increased costs due to load growth while ignoring the corresponding benefits of increased revenues.

Q. HAS THE COMPANY DEVELOPED FORECASTED BILLING UNITS FOR THE 2009 TEST YEAR?

A. No. However, the NVPC portion of rates is collected on a per KWh basis from customers with very little difference between customer classes. As a result, imputing the additional revenue based on the increase in sales growth is an excellent estimate of the impact. This is the approach I used in Table 1.

III. GRID STRUCTURE AND LOGIC ISSUES

Q. WHAT ARE "NET VARIABLE POWER COSTS" AND WHY ARE THEY IMPORTANT TO THIS PROCEEDING?

A. Net variable power costs are the variable production costs related to fuel and purchased power expenses and net of sales revenue. The Company estimated these costs for the Calendar Year 2009 test period using the GRID model. NVPCs comprise a substantial portion of the Schedule 200 revenue requirement and are a significant component of PacifiCorp's overall rate levels.

GRID OVERVIEW AND ISSUES

Q. WHAT IS THE PURPOSE OF GRID?

A. The purpose of the GRID model is to estimate NVPC by modeling the <u>least cost</u> operation of the PacifiCorp resources, subject to serving load and all applicable constraints. This is clearly stated in the GRID Algorithm Guide:

> **"GRID (<u>G</u>eneration and <u>R</u>egulation <u>I</u>nitiative <u>D</u>ecision Tools) is a production cost model that *dispatches PacifiCorp resources to serve load obligation through the most economic means*. Core functions include:**
>
> - **Committing thermal generating units against market price**
> - **Shaping hydro generation against net system load**

- **Shaping long-term firm contract energy per contract terms against market price**
- **Calculation and satisfaction of reserve requirement**
- ***Balancing and optimization of the Company's resources given transmission and market constraints, including market purchases and sales*"** (emphasis added)[3/]

The above stated description is typical of the mainstream utility production cost models in use in the industry today. As a matter of course such models assume system operating costs are minimized subject to operational constraints, such as transmission limitations. Simulation of the "least cost" operation of the system is the paradigm assumed by all industry standard production cost models and is the stated goal of the GRID model.

Q. DOES GRID ACTUALLY ACCOMPLISH ITS GOAL OF SIMULATING COST MINIMIZATION GIVEN THE SYSTEM CONFIGURATION IT MODELS?

A. No. GRID frequently fails to develop the least cost operation of resources. In fact, there are thousands of hours per year when gas-fired generators are not operating economically within the model. This results in a spillover effect to coal-fired generation. Frequently, the uneconomic operation of gas plants forces lower cost coal units to have their output curtailed. I estimate the model produces additional costs of more than $15 million dollars due to this problem alone, or about 1.5% of total NVPC.

Q. DO YOU BELIEVE THAT IN ITS REAL TIME OPERATIONS THE COMPANY SEEKS TO MINIMIZE OPERATING COSTS, SUBJECT TO CONSTRAINTS?

A. Yes. As part of the current Utah general rate case I interviewed personnel from PacifiCorp's real time operations staff in Portland on February 15, 2008. We

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3/ GRID Algorithm Guide, V6.2, dated December 2007, as supplied by PacifiCorp on the GRID computer, page 4.

discussed, in depth, the techniques used by the Company to optimize unit commitment and dispatch decisions and did follow up discovery. It was stated that the Company believes instances of incorrect commitment and uneconomic generation, while possible, are rare events. At this time, I have no reason to doubt this. Indeed, I expect the Company typically attempts to achieve the least cost operation of the power system, subject to applicable constraints.[4/] Note that I am not endorsing the prudence of every aspect of PacifiCorp's operations in this statement. It applies solely to system commitment and dispatch decisions.

Q. WHAT CONSTRAINTS ARE MOST SIGNIFICANT IN GRID?

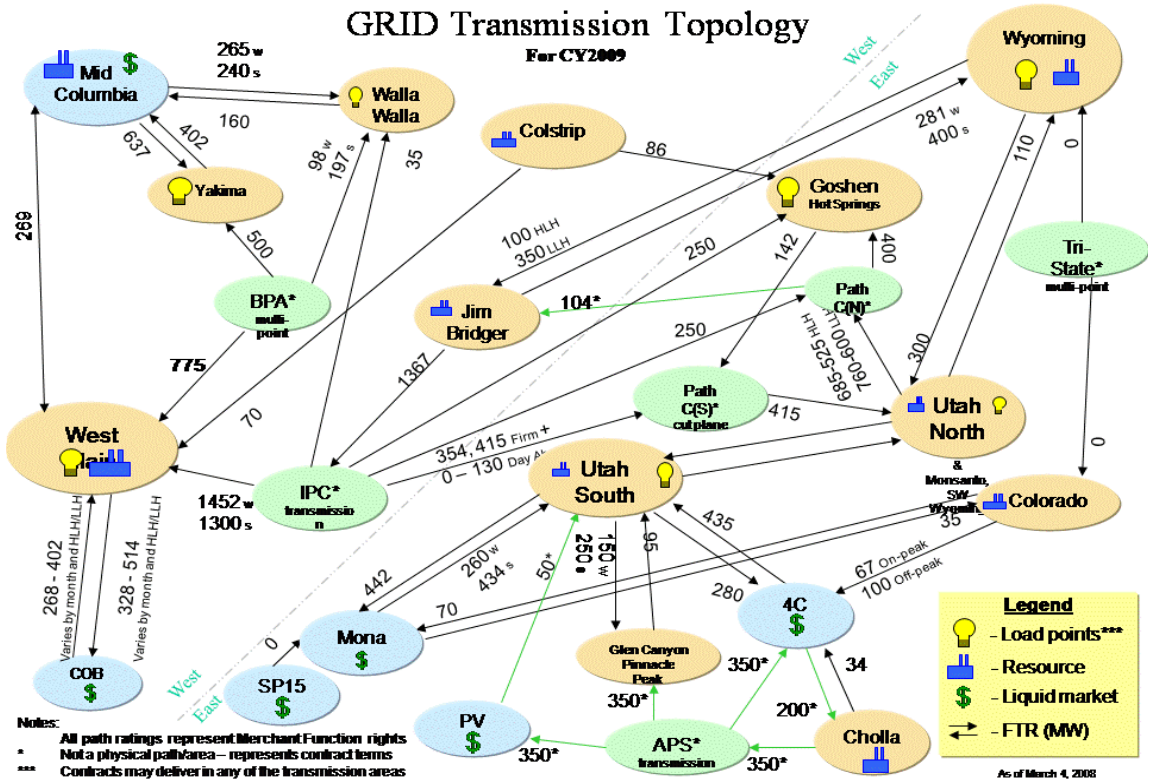
A. The most serious constraints are imposed by firm transmission limits and market caps.[5/] These are significant because without the free flow of power across the transmission network or liquid markets for transactions, the Company cannot always sell available excess generation, purchase the least cost energy available, or operate units at their most efficient loading levels. The figure below shows a copy of the current GRID Transmission Topology Map.[6/] This map shows the system is quite complex and transmission paths have limited capacities.

4/ It was also noted during this meeting that availability of non-firm transmission is a key element in the cost minimization process. The implications of this will be discussed later.

5/ Market caps represent limits on the amount of energy that can be sold in a given market. In GRID market caps are applied during the hours 1-6 am, based on historical data. I have concerns about the development of this data, but did not address that in this case.

6/ Obtained from PacifiCorp's response to ICNU DR 1.3-1.

FIGURE 1: GRID TRANSMISSION TOPOLOGY MAP



In addition, there are various operating constraints, including unit minimum loading levels, reserve requirements, minimum up and down times for generators, and market liquidity limits (market caps). All of these factors are simulated in GRID, and are interrelated. For example, if the Company has excess generation, but is unable to sell the energy due to transmission constraints, units are required to reduce output. In such instances units may be dispatched in GRID at their minimum loading levels, which is typically their least efficient loading.

Q. PLEASE PROVIDE EXAMPLES OF TRANSMISSION LIMITATIONS THAT RESULT IN OPERATIONAL CONSTRAINTS WITHIN GRID IN TERMS OF RUNNING GENERATION RESOURCES?

A. GRID simulations reveal that several of the key transmission links are heavily constrained. Further, owing to market capacity limits assumed in GRID, there are additional constraints that occur (and are generally binding) every day for five hours, from 1 am until 6 am. The net result of these constraints in GRID is that PacifiCorp generators frequently run at minimum loading levels. For example, Currant Creek and Lakeside are assumed to be operating at its minimum loading approximately 3200 hours per year, or nearly 50% of the time these units are running. The Gadsby combustion turbines are shown as running at minimum several thousand hours per year, and almost 100% of the time they are operating.

Even coal plants are shown to frequently be operating at minimum loadings in GRID. For example, GRID results show Carbon 1 operating at minimum loading more than 2000 hours per year (24% of total operating hours), Cholla 4 and Naughton 2 operating at minimum loading for more than 1200 hours (15% of their total operating hours).

Q. ARE THESE GRID RESULTS REALISTIC?

A. No. The Company generators run at minimum loadings far less often than is portrayed by the GRID model. All of this suggests a serious problem with the dispatch and commitment logic in GRID. However, there is even more serious direct evidence of this problem.

Q. DESCRIBE THE DIRECT EVIDENCE OF UNECONOMIC GENERATION IN GRID.

A. As I previously discussed, GRID is supposed to simulate the *least cost* operation of system resources. If it costs less to *not* run a particular unit for a particular period of time, the model should simply not commit it in the first place. This is particularly true of gas-fired units, which have the ability to cycle on a daily basis. To provide a proper modeling, the daily decision to start up a unit (in GRID) should reduce - not increase - NVPC, unless it is needed for purposes of meeting reserve requirements. Yet, I found that when the new combined cycle resources were removed from GRID in certain months or at certain times, NVPC actually declined. In GRID these units are started up (or left running) even though they are not needed for reliability purposes, and are not part of the least cost operation of the PacifiCorp system. This is a clear cut error in the implementation of the model.

Q. PLEASE PROVIDE EXAMPLES OF THIS PROBLEM?

A. The most significant problem concerns the modeling of Currant Creek. While GRID shuts down the Currant Creek plant more than 275 nights in 2009, it leaves the plant running the remaining nights. However, a run that required the Currant Creek plant to shut down every night produces substantially lower NVPCs. Further, a run performed without Currant Creek running at all, produced NVPCs some $2 million less than the run including those units in April and May 2009. Likewise, runs requiring that Lakeside be shut down every night produced a substantial reduction to NVPC. In all of these cases, GRID would produce lower production costs if the resources were simply removed from the dispatch sequence during the time periods discussed. These examples clearly show that a serious problem relating to uneconomic generation exists in GRID.

Q. IS OPERATION OF THESE UNITS REQUIRED FOR MEETING RELIABILITY REQUIREMENTS IN GRID?

A. No. In GRID, reliability requirements are modeled by specifying an hourly reserve capacity requirement. GRID computes hourly “Reserve Shortage” if there is not enough capacity on line to meet reserve requirements. Review of the

Reserve Shortage results from the GRID model shows no impact when these resources are removed during the periods of uneconomic generation. GRID simply uses other (already available) capacity to meet reserve requirements when these new combined cycle units are removed from the model. Therefore, the increased cost cannot be tied to a need to meet reserve requirements.

Q. IS IT POSSIBLE THIS PROBLEM IS RELATED TO OTHER OPERATING CONSTRAINTS, SUCH AS MINIMUM UP OR DOWN TIMES?

A. No. Again, the resources in question can cycle on a daily basis.

Q. DO YOU KNOW WHY THIS PROBLEM IS OCCURRING?

A. The problem is occurring because the logic in GRID divorces the decision to commit (start up or not to shut down) a resource from the operating constraints (transmission limits and market capacity limits) imposed by model inputs. However, these operating constraints are used later to determine the optimal dispatch of resources. The simplest explanation is the model unrealistically assumes energy produced by a generator can always be sold in various markets when making the commitment decision. As a result, units are running when there is no market for the energy they produce.

Q. EXPLAIN THE DIFFERENCE BETWEEN COMMITMENT AND DISPATCH IN GRID.

A. Commitment is the determination of which units are (or should be) running in a particular hour. Once the model determines a unit is committed (i.e., running), a unit must run at least at its minimum loading level. Dispatch is the determination of the level at which each of the committed units will actually run. Units generally are most efficient at or near full loading, and least efficient at minimum loading. The Linear Programming ("LP") module in GRID determines the dispatch of committed resources that minimizes total cost, subject to the constraints imposed. However, that the LP module does not decide which units *should* be running and cannot reverse an incorrect commitment decision made previously by the model.

Q. EXPLAIN HOW GRID SIMULATES THE COMMITMENT AND DISPATCH OF UNITS.

A. This is a two-step process. The model first develops a list of "committed" units for each hour. Once that step is completed, the LP module solves for the most efficient dispatch of resources, subject to transmission and other operating constraints (such as minimum loading requirements). Frequently, there are too many units committed during a specific hour and the model produces a dispatch that exceeds the least possible cost. As a result, removing certain units from the entire dispatch and commitment sequence can actually lower NVPC because GRID makes a mistake in deciding which units to have running in the first place.

This occurs because the commitment logic is premised on a comparison of market prices to the dispatch cost of individual resources. In effect, the model assumes that if a resource is started up, all of the additional energy produced by the unit can be sold at market prices or will offset Company owned generation costing that much or more.[7/] However, transmission constraints and market caps frequently limit the amount of energy that can be sold in the market, particularly

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[7/] GRID Algorithm Guide, V6.2, dated December 2007, as supplied by PacifiCorp on the GRID computer, pages 47-53.

the energy from resources in the Utah North and Utah South transmission areas.[8/] This is the major source of uneconomic generation in the GRID model.

Q. EXPLAIN THE PROBLEMS RELATED TO THE UTAH TRANSMISSION AREA RESOURCES.

A. As shown in the topology map in Figure 1, there is a vital transmission link available between the Utah resources and the Four Corners market hub. In GRID, the Company uses Four Corners as the reference market price for resources in the Utah transmission area. GRID assumes that if a unit is started up, it will either be able to sell its energy in the Four Corners market (or will enable another, lower cost unit to do so).

Q. IS THAT A REALISTIC ASSUMPTION?

A. No, far too often it is a completely *unrealistic* assumption. From reviewing the GRID hourly transmission reports I learned the Utah South to Four Corners link is constrained 5175 hours per year by transmission limitations. Further, market caps limit the ability to sell into this market 1409 hours per year (during the "graveyard shift" hours). Combined, this means there is no market for incremental sales to Four Corners for as much as 6584[9/] hours during the test year, or about 75% of the time. In effect, GRID starts up (or does not shut down) the combined cycle units in order to make additional sales, but there is no way to actually deliver that energy to the Four Corners market 5175 hours per year and no market another 1409 hours per year. Sales at night to Four Corners are limited by market caps to less than [redacted] on average during the "graveyard shift" hours. However, the

8/ While these are modeled as two separate areas in GRID, they have a very large transfer capability, thus constraints between these two areas are not a significant problem.

9/ 5175+1409

model frequently allows Currant Creek and Lakeside to continue to run at night, under the false assumption that it would be possible to sell output from the plant at market prices. This leads to a substantial and costly mistake in the simulation of Currant Creek operations that I do not believe actually happens in real-time operations.[10/]

Q. HAS THIS PROBLEM EXISTED IN THE MODEL FOR SOME TIME?

A. I believe so. However, its nature has not been so obvious in the past. Further, the problem has recently been exacerbated by load growth (resulting in increasing constraints on the system) and the addition of various resources on the system, including certain call options, Currant Creek and Lakeside. Because GRID does not consider operating constraints when committing resources, Currant Creek and Lakeside are operated in an uneconomic manner in the model.

Q. PLEASE DISCUSS SOME OF THE PRIOR INDICATIONS OF THIS UNECONOMIC GENERATION PROBLEM.

A. As early as Wyoming Docket No. 20000-ER-03-198, the Company's witness, Mr. Mark Widmer, acknowledged that combustion turbines were dispatched incorrectly in GRID and agreed in his rebuttal testimony to a $1 million disallowance to address the problem.[11/] Similar issues have been raised in subsequent PacifiCorp cases, though most have been settled with regards to power cost issues.

In UE 191, the Commission adopted $9.96 million in disallowances directly or indirectly related to addressing the uneconomic generation problem.

10/ In real–time operation, the availability of non-firm transmission capacity may enable some sales to other markets, thereby avoiding the need to reduce energy from, or shut down, Currant Creek.

11/ Re PacifiCorp, Wyoming Public Service Commission Docket No. 20000-ER-03-198, Final Order at ¶ 35 a2 (Feb. 28, 2004).

Exhibit ICNU/102 shows the November 7, 2007 GRID update in the case referenced above. The final three adjustments listed in this exhibit (Uneconomic CT operation, Call Options and Carbon at 80% CF) are all symptomatic of the problem of uneconomic generation in GRID.

Q. HAS THE COMPANY ACKNOWLEDGED A NEED TO CHANGE THE GRID LOGIC IN ITS FILING IN THIS CASE?

A. Yes. In the Company' s direct testimony, Mr. Duvall testified that a change made in GRID "*enhances the system balancing logic to better recognize economic displacement by decommitting eligible thermal units. Previously, the Company used a manual workaround*."[12/]

Q. DOES THE NEW LOGIC IN GRID 6.2 SOLVE THE UNECONOMIC GENERATION PROBLEM?

A. No. The new logic has done little to address the uneconomic generation problem. Indeed, GRID runs that I just discussed clearly show that the problem remains, even with the Company's latest "fix" invoked.

The new logic change does not address the problem of the failure to connect the commitment logic with operating constraints. Rather, it makes yet another ad-hoc adjustment by de-committing units once a certain (judgmentally determined) level of capacity "displacement" is reached. In this context "displacement" is the amount of capacity committed in excess of the actual requirement.

[12/] PPL/100, Duvall/10.

Q. IS THIS THE ONLY TIME THE COMPANY HAS TRIED TO ADDRESS THE UNECONOMIC OR INCORRECT GENERATION PROBLEM.

A. No. For some time the Company has prevented GRID from running combustion turbines during night time hours. Further, in the recent Wyoming case, the Company made a new ad-hoc adjustment to the commitment fuel cost in GRID in order to "trick" the model into reducing the number of starts of certain gas units. This is the "manual work around" discussed in Mr. Duvall's testimony in this case. Finally, the Company uses a "reserve credit" designed to stimulate the start up of certain units to free up lower cost units from providing reserves. I believe this calculation has been changed in recent GRID versions, but fails to solve (and may even exacerbate) the problem of uneconomic generation.

Q. HAS THE COMPANY FINALLY ADMITTED TO THIS PROBLEM?

A. Yes. In the current Utah rate case, when confronted with similar evidence the Company finally admitted to this problem in GRID. In his surrebuttal testimony, Mr. Duvall stated as follows:

> The Company agrees that GRID should simulate normal prudent operation of the system. Absent unusual circumstances, the Company would not run its gas units in a manner that would cause its less expensive coal plants to back down. To the extent that GRID systematically dispatches resources in this manner, the Company agrees that the model needs to be adjusted.
>
> * * *
>
> **Q.** How has the Company addressed this issue to date?
>
> **A.** The Company has addressed this issue in two ways. First, when it has become clear that the model is systematically dispatching units in an uneconomic manner, the Company has applied manual workarounds (i.e. turning off the ability of the model to dispatch a certain unit at a certain time). Second, the Company has worked to refine and improve GRID's commitment logic in the last two upgrades to the model to eliminate the need for such manual workarounds.

> **Q.** Has the most recent version of GRID completely resolved this issue?
>
> **A.** No. The most recent version of GRID addresses and ameliorates the issue but did not resolve it in all cases.
>
> **Q.** How does the Company propose to address this issue in this case?
>
> **A.** The Company agrees that a manual workaround should be applied to prevent systematic uneconomic dispatch of the West Valley, Currant Creek and Lakeside plants[13/].

In the end, Mr. Duvall admitted in the Utah case that GRID contained errors that GRID overstated net power costs by $18 million on a total Company basis.

Q. PLEASE COMMENT ON THESE STATEMENTS.

A. Based on Mr. Duvall's Utah testimony, it appears that the Company has known of this problem for quite some time, but failed to disclose it to its various regulators. Indeed, until recently, the Company has only agreed to make these kinds of adjustments in other states when the issues were raised by intervenors. Situations like the TAM case are generally problematic because there is limited time to perform discovery and diagnose these kinds of problems.

Q. DESPITE THE ADMISSIONS ABOVE, DID THE COMPANY ACTUALLY APPLY THE MANUAL WORKAROUND DESCRIBED IN MR. DUVALL'S TESTIMONY?

A. No. Mr. Duvall simply adopted the Utah Division of Public Utilities ("DPU") power cost study (after making a few other adjustments to it to increase power costs). That study did not correct the problem. Indeed, the Utah DPU did not even address the problem in its testimony, nor did their witness pass judgment on

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13/ Re Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates, Utah Public Service Commission Docket No. 07-035-93, at 15-16. (Rebuttal Testimony of Gregory N. Duvall).

the issue. Despite admitting to this problem, Mr. Duvall, and the Company continued to recommend regulators adopt GRID studies, knowing full well the problem was still present in his recommended GRID study. Further, as is apparent already, the Company filed its case in this proceeding, long after having evidence presented to it in the recent Wyoming case that the problem of uneconomic generation was still present in GRID.

Q. IS THERE A LONG-TERM SOLUTION TO THIS PROBLEM?

A. Yes. The Company needs to change the GRID logic to harmonize the commitment decision process with the operating constraints. I recommend the Commission require the Company do so before it files its next Oregon TAM or general rate case.

Q. IS IT REASONABLE TO EXPECT THE COMPANY TO FILE ITS NEXT TAM OR GENERAL RATE CASE WITH A CORRECTION TO GRID?

A. Yes. In Docket No. UE 149, I discovered a similar problem related to PGE's Monet modeling of its gas-fired combined cycle resources. In that case, PGE and ICNU reached a settlement where that company agreed to work with parties to resolve this problem via an update to Monet. This was accomplished by the next RVM case filing, UE 161. I reviewed the modeling change in that case, and in subsequent cases. I found that Monet indeed did (and still does) eliminate all instances of uneconomic generation from its gas-fired plants. Clearly, if PGE can make a modeling change to accommodate such a problem in less than one year, PacifiCorp can do so as well.

Q. HAVE YOU DEVELOPED AN INTERIM SOLUTION FOR THIS CASE?

A. Yes. For purposes of this case, I have developed an interim solution. My solution is illustrated in Exhibit ICNU/103. Note that I am proposing the application of this methodology to the final GRID model adopted by the Commission, rather than just the specific inputs that I developed using this method. This will require that the Company make all other Commission-approved adjustments to the model, and then implement my proposed methodology in their final GRID runs.

Q. DESCRIBE THE METHODOLOGY YOU PROPOSE.

A. This solution rests on comparison of two GRID runs, with and without a specific resource, or group of resources. In Confidential Exhibit ICNU/103, I show the calculation used for Currant Creek based on analysis of hourly cost data for three specific days. The proposed solution compares the daily cost of fuel and purchased power costs and net of sales revenue in the "with" and "without" Currant Creek cases.[14/] To ensure that this provides the correct analysis of the GRID results, I took care to reconcile my annual sum of the daily cost results (based on GRID daily outputs) with the annual results computed "inside" the model provided in the GRID annual output reports. In the end, I was able to decompose the annual change in costs into individual daily and hourly components. Thus, I was able to ensure that daily cost variations are consistent with the total cost variations produced by the model. I also reviewed the reserve shortage outputs from GRID to ensure that there were no significant reliability impacts resulting from removal of these units during the indicated periods.

14/ These items represent the variable costs modeled in GRID in most circumstances. In cases where call options are modeled, then variable energy costs from those contracts are included as well.

As a general matter, Currant Creek and Lakeside should use a simple night time shut down screen (the approach the Company already uses for the less efficient gas-fired units). However, in the case of Currant Creek, additional daytime shutdown screens are needed.

Based on this analysis, I was able to determine the impact on NVPC of including or removing specific resources. As a result, I identified the specific times when the resource (in this case Currant Creek) should not have been running. In the first and third examples (January 1, and May 5, 2009) Currant Creek should have been shut down the entire day. In this case, even though GRID is shutting down the unit at night, it should not be restarted the next day. In the second example, July 13, 2009, Currant Creek should be running in the day time, but shutdown at night. This illustrates a situation where a night-time only shut down screen should be used.

In Confidential Exhibit ICNU/104, the development of the night time shut down screens is shown. The exhibit compares hourly variable power cost by hour of each month in the Currant Creek case and without Currant Creek cases. The negative numbers indicate hours when Currant Creek should be running. The positive numbers indicate the hours when it should not be running. The screen selected shuts down Currant Creek for 7 hours starting at 10 pm each night.

From review of daily cost comparisons, it can be seen that GRID is erroneously committing Currant Creek nearly every day from April 2, 2009, to June 1, 2009. My solution simply removes Currant Creek from operation on those days and turns both the Currant Creek and Lakeside combined cycle units off at night. In effect, this amounts to manually de-committing the resource. *This is nothing more than what GRID* <u>*should*</u> *be doing correctly in the first place.*

Because all of the improperly committed resources can cycle daily, there is no reason why they could not be shut down on specific days. As a result of this analysis, I was able to identify the specific days and times when the units should not have been committed by the model.

Q. WHY IS IT REASONABLE TO SIMPLY "TURN OFF" SPECIFIC UNITS AT SPECIFIC TIMES?

A. This is nothing more (or less) than what the GRID model is attempting to do (and should be doing correctly) anyway. GRID is trying to decide which days each unit should be started up, and how long they should run. GRID does not start any of these units every day. However, the model fails to determine the correct days and hours when the various units should be running. This procedure corrects that problem. In the end, I've done nothing more than the Company did with its night time shut down screen for peaking units, which has been applied now for several cases. However, I've applied it much more systematically to other units to produce a more economic dispatch of generation resources.

Q. DID YOUR ANALYSIS ELIMINATE ALL OF THE UNECONOMIC GENERATION COSTS IN GRID?

A. No. I did not eliminate all uneconomic generation costs for a number of reasons. <u>First</u>, I did not attempt to develop the most economic screens on a daily basis. To do so would have been much more time consuming. <u>Second</u>, I did not fully examine all of the units that may have been impacted by the problem. For example, I did not apply the methodology to the Gadsby units. Some preliminary analysis, however, suggested these resources were not impacted by the problem to the degree that the other units were, particularly after the adjustments to the other units were made. Third, my approach only eliminated periods of uneconomic generation from the model. I did not attempt to determine if GRID was failing to start up units when they otherwise should have been running. Finally, I departed from the most optimal hourly screens to simplify the GRID inputs I developed as a concession to time constraints. (In theory, there could be a different night time shut down screen every day of the year). I would note that such departures should not be taken as an endorsement of sub-optimal modeling of system resources.

Q. EXPLAIN THE ADJUSTMENTS YOU COMPUTED IN TABLE 1.

A. In Table 1, I present the results of GRID runs performed with these adjustments invoked on a sequential basis. Thus, the table reflects the balancing effects of these adjustments in tandem. Were they applied individually the impact would likely be greater. I note that there is also a small amount of incremental start up fuel and O&M expenses resulting from daily cycling of the combined cycle units. I estimate these to be less than $3.1 million. However, it is my understanding that the Company already accounted for these kinds of costs using historical data in other components of its UE 179 test year, rather than using GRID outputs. Because this category of costs were included in base rates already, it would not be appropriate to include them in the TAM, which is limited solely to net variable power costs that were heretofore included in GRID.[15/] The Company may want to make an request for these additional costs in the next general rate case in Oregon.

[15/] Re PacifiCorp, Docket No. UE 191, Order No. 07-446 at 22 (Oct. 17, 2007). In Order 07-446, the Commission rules specifically against broadening the scope of the TAM proceedings to include O&M costs and other non NVPC related items.

IV. CONTRACT MODELING IN GRID

Q. DOES GRID MODEL PURCAHSE AND SALE CONTRACTS?

A. Yes. The Company includes the costs and energy produced by its long-term and short-term contracts in GRID, along with its thermal generation resources, in order to project normalized NVPC. I will discuss issues related to certain aspects of PacifiCorp's long-term contracts.

CALL OPTION PURCHASE CONTRACTS

Q. WHAT IS A CALL OPTION CONTRACT?

A. These are contracts that allow the Company the right to schedule energy on a daily basis when the market price exceeds the contract strike price.

Q. WERE CALL OPTIONS ADDRESSED IN UE 191?

A. Yes. The Company proposed to remove these contracts if they failed to dispatch economically in GRID or during months when the contracts did not dispatch at all in GRID. I agreed with that proposal, and it was adopted by the Commission in UE 191. As an aside, this issue was intimately related to the problem of uneconomic generation discussed above.

Q. DID THE COMPANY APPLY THE COMMISSION APPROVED METHODOLOGY FROM UE 191 IN THIS CASE?

A. No. The Company did not do so. The Company proposed (and Commission approved) methodology would apply in the case of Morgan Stanley contract p272158, because the contract did not dispatch in June 2009. Removing the contract during that month reduces NVPC by the amount shown in Table 1.

Q. DOES THE COMPANY AGREE TO USE ITS UE 191 PROCEDURE IN THIS CASE?

A. No. In response to ICNU DR 1.46, the Company indicated it believed that similar regulatory treatment based on the prior case precedent may no longer be applicable because of changes to the test year, and other factors. ICNU/115, Falkenberg/3. I disagree, and see no reason why the method the Company proposed and the Commission adopted in UE 191 would not apply in this case as well. The method used in UE 191 was a reasonable approach to dealing with contracts that provide no benefits to ratepayers. It makes little sense for the Company to execute call options that they do not expect to be dispatched based on the assumed forward curve while expecting the customers to pay the associated demand charges. Such contracts provide no reliability benefits in GRID because they are assumed to provide reserves. I see no justification for including these contracts in the test year in months they don't dispatch.

CALL OPTION SALE CONTRACT MODELING

Q. IS THE CALL OPTION PURCHASE DISCUSSED ABOVE THE ONLY CALL OPTION MODELED IN GRID?

A. No. The Company models "call option sales" for the Sacramento Municipal Utility District ("SMUD") and Black Hills Power ("BHP").

Q. EXPLAIN THE MODELING OF CALL OPTION SALES IN GRID.

A. In GRID, the model can specify whether such contracts are modeled having energy limits on a daily, weekly, monthly or annual basis. For sales with annual contract energy limits, such as SMUD, GRID schedules the contract energy during the highest cost hours of the year. Since the contract has an annual energy limit of approximately 350,400 MWh (with a 100 MW maximum hourly take), this means GRID assumes SMUD will call the energy from the contract during the highest cost[16/] 3504 hours[17/] in the year. As a result, GRID assumes no energy is requested by SMUD during the low cost months from April to June.

Q. AS A GENERAL MATTER, DOES GRID OPTIMIZE THE USE OF ENERGY FROM PURCHASE AND SALES CONTRACTS?

A. No. *GRID only optimizes a handful of call option purchase and sales contracts*. For the great majority of the contracts modeled in GRID, the simulation amounts to nothing more than using the available energy at user specific times.

Q. IS THE GRID MODELING OF THE SMUD CONTRACT REALISTIC?

A. No. Based on historical data the GRID modeling is flawed. In fact, the Company's assumptions amount to determining the "worst case scenario" when it comes to the SMUD contract and are completely at odds with actual practice.

Q. PLEASE EXPLAIN.

A. The table below shows the actual monthly distribution of SMUD energy for the four-year period (2003-2007)[18/] as compared to the GRID simulation result. It is quite apparent that SMUD takes energy at substantially different times than predicted by GRID. This is not surprising since SMUD is attempting to optimize the use of the contract for its own purposes, and based on its own constraints, rather than using the contract in a punitive manner to impose the maximum cost on PacifiCorp (as is assumed by GRID). For whatever reasons, SMUD is not using the contract in the "most cost" manner assumed by the Company in GRID. The historical data presented in the table below shows that SMUD takes energy

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16/ Based on COB ("California Oregon Border") market prices.

17/ 350,400/100 = 3504.

18/ Source: Committee of Consumer Services ("CCS") DR 13.8 in Utah Public Service Commission Docket No. 07-035-93.

associated with the contract in a much lower cost schedule than assumed in GRID.

TABLE 2

SMUD LTF CONTRACT: ACTUAL VS. GRID MWH

Month	4 Yr. Avg	GRID
1	50,352	42,000
2	46,325	36,000
3	31,371	7,100
4	30,754	-
5	30,039	-
6	35,056	-
7	44,879	33,500
8	34,914	51,800
9	0	44,800
10	18,349	37,700
11	17,696	41,000
12	10,665	56,500
Total	350,400	350,400

Q. HOW DID YOU ADDRESS THIS PROBLEM?

A. I developed the monthly energy for SMUD for the Test Year based on the four-year average from 2003 through 2007. I still assumed that on a monthly basis, SMUD would optimize the contract based on maximizing COB market revenues. This approach may well overstate the cost of serving SMUD, since they may not do a "most cost" dispatch on a monthly basis any more than they do on an annual basis. Nonetheless, this adjustment provides a reasonable start towards rectifying this problem. This adjustment is shown in Table 1.

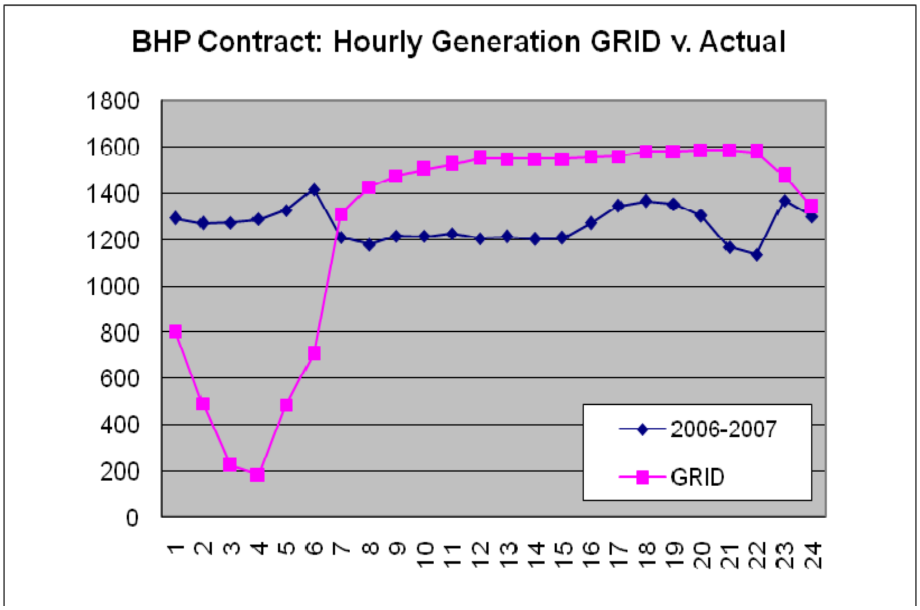
Q. PLEASE DISCUSS THE BHP CONTRACT MODELING.

A. BHP is another call option sale. In this case, the Company models weekly contract energy limits. As a result, GRID attempts to find the highest cost hours during each week when BHP could request delivery. As in the case of SMUD, GRID assumes a "most cost" dispatch of the contract by BHP. In this case, the

Company assumes that Four Corners is the appropriate market, while in the case of SMUD the reference market is COB.

Q. IS THE GRID MODELING OF THE BHP CONTRACT REALISTIC?

A. No. The figure below shows the actual hourly energy dispatch of the BHP contact for the period 2006-2007 as compared to GRID.



As the figure shows, GRID shows generation under the contract dropping to nearly zero at night, then increasing substantially during high load hours. However, BHP actually uses the contract as a baseload resource, with nearly a flat delivery pattern. It should be fairly obvious that the delivery pattern assumed in GRID is much more expensive than the actual delivery pattern used by BHP.

Q. CAN YOU EXPLAIN WHY BHP MAY NOT 'OPTIMIZE' ITS TAKE OF ENERGY FROM THIS CONTRACT?

A. I have been involved in every BHP general rate case since approximately 1990. I also participated in cases concerning the construction of new capacity by BHP and power cost adjustments, and have developed an understanding of the BHP system.

The BHP system is quite small, and has a limited number of resources. The Company also has somewhat limited transmission interconnections. BHP also has substantial coal reserves and mines coal for all of its own plants, including Wyodak. However, BHP is somewhat unique in that it is interconnected to both the eastern and western grid, via a DC intertie in Rapid City. In fact, BHP can arbitrage between the eastern and western GRIDs. Thus, the reference market price for BHP is not necessarily Four Corners, and BHP lacks transmission capacity, and operational flexibility that might enable it to cycle the purchase from PacifiCorp up and down as the Company assumes.

Originally, the BHP contract was known at BHP as the "Colstrip contract" because it had pricing specified based on the Colstrip plant. As a result, I believe that BHP has long viewed this contract as a baseload resource and operates in that manner. Clearly, the Company has not attempted to model how the counterparty actually uses the contract, but instead models it as a cycling type resource, rather than as a baseload resource.

Q. IN THE RECENT UTAH CASE YOU PROPOSED A SIMILAR ADJUSTMENT FOR THE SMUD CONTRACT. HOW DID THE COMPANY RESPOND?

A. Mr. Duvall argued it was inconsistent to optimize the Company's generators, such as Currant Creek, while "de-optimizing" only a few selected contracts. This is erroneous because, as noted above, GRID only optimizes a few call option contracts. It appears Mr. Duvall mistakenly believed GRID performed a similar optimization for all contracts. Further, the optimization of Currant Creek and Lakeside follows the actual goals and practices of system operation. The actual usage patterns of SMUD and BHP follow whatever actual optimization is practiced by the counterparties, subject to their unique constraints. Mr. Duval is really suggesting the counterparties are imprudent because their goal is not to maximize cost to the Company.

SMUD CONTRACT PRICING

Q. ARE THERE ANY OTHER ISSUES RELATED TO SMUD?

A. The Commission has imputed a price to the SMUD contract of $37/MWh since the settlement in Docket No. UE 111. This price was based on a 1999 Utah decision. Since the time of the original development of the $37/MWh price, the cost of serving SMUD has increased dramatically while the revenue paid to the Company by SMUD has increased as well (from $14.66/MWh in 1999 to 21.46/MWh in 2008). In the end, the Company's disallowance has shrunk while the overall cost to the customers has grown substantially. As a matter of fairness, I believe the SMUD imputed price should be reset and indexed to the actual contract price.

Q. HOW WOULD YOU DETERMINE THE IMPUTED PRICE?

A. The most basic fact concerning SMUD is that the contract was known from the start to be below market and that the Company retained an up front payment of $98 million from SMUD to enter into the contract. It is reasonable to assume that the $98 million up front payment was sufficient to bring the SMUD contract in line with the market at the time the contract was negotiated. If the up-front payment had been recovered via a demand charge over the term of the contract, SMUD would likely be viewed as just another legacy contract. To bring SMUD into alignment with the market at the time it was negotiated, it makes sense to assume the up-front payment was recovered over the term of the contract. Based on a constant per KWh charge, this would amount to $20.5/MWh. Adding this amount to the current contract price would produce an imputed price of $42/MWh, resulting in an adjustment in the amount shown in Table 1. I also recommend this amount be updated each year based on the projected SMUD contract price for the test year.

HERMISTON LOSSES

Q. PLEASE EXPLAIN THE HERMISTON LOSS ADJUSTMENT IN GRID.

A. The Company wheels Hermiston power over the Bonneville Power Administration ("BPA") transmission system. As a result, the Company imposes losses on the BPA system that it must later return to BPA. The Company models these losses as a zero revenue sale in GRID.

Q. DO YOU AGREE WITH THE LEVEL OF LOSSES ASSUMED IN GRID?

A. No. The workpapers computing the losses included in GRID are premised on an assumed loss level of 75,000 MWh per year allegedly occurring during the period October 1999 to January 2005. As part of the recent Utah case, I inquired about this figure during the on-site interviews and in a subsequent data request (CCS DR 15.2 in Docket No. 07-035-93). In neither case could the Company explain the source of the figure used and indicated only that it was an estimate.

ICNU/115, Falkenberg/4. Exhibit ICNU/105 shows excerpts from the Company workpapers and my correction to it.

Q. PLEASE EXPLAIN YOUR CORRECTION TO THE LEVEL OF HERMISTON LOSSES?

A. In discovery in the current Wyoming PCAM case I obtained a letter from BPA to PacifiCorp showing the monthly losses during this period. Exhibit ICNU/106 shows a copy of a letter from BPA to PacifiCorp indicating the actual losses that occurred during the period in question. My calculation shows that the correct level of losses for the period was only 55,000 MWh per year. Reducing the losses in GRID to the appropriate level produces the adjustment shown in Table 1.

Q. WAS THIS ISSUE RAISED IN THE CURRENT UTAH CASE?

A. Yes. While Mr. Duvall seemed to agree that the Hermiston loss figures were overstated, he did not reflect this adjustment in his recommended final net power costs because he believed it was an update reflecting new information. This is rather ironic because the correct loss information is from a three year old letter.

V. PLANNED OUTAGE SCHEDULE

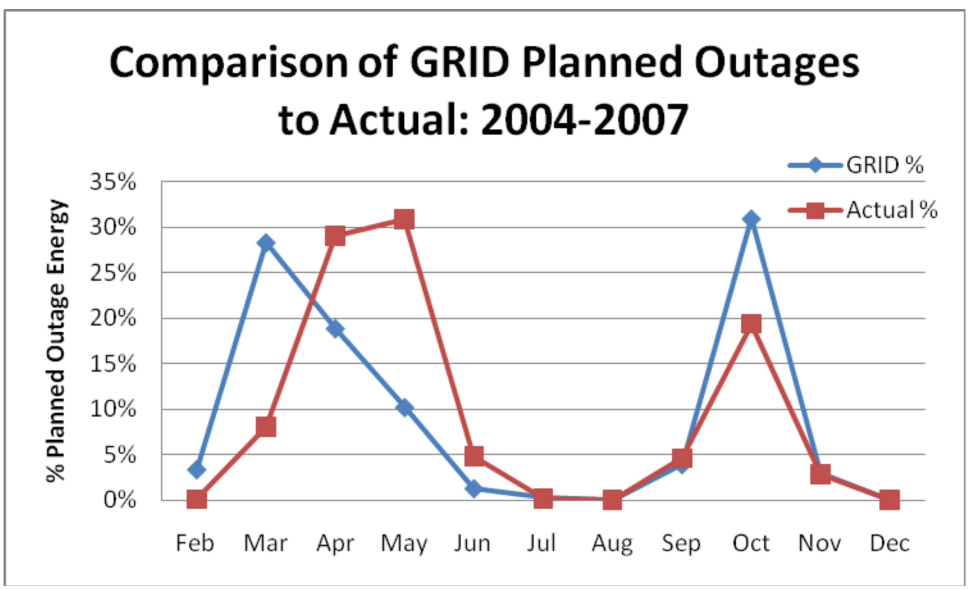
Q. WHAT ARE PLANNED OUTAGES?

A. Planned outages represent events where generators are taken out of service for routine scheduled repairs and maintenance. Plants are typically taken down once per year for scheduled work, while individual units may only be taken down once every four years. During the on-site interviews I conducted on February 15, 2008 in the Utah case, I learned this work is normally scheduled in the spring when demand and market prices are at their lowest levels. This makes perfect sense, and constitutes a prudent, cost minimizing practice by the Company.

Q. DOES THE COMPANY USE THE ACTUAL GENERATOR MAINTENANCE SCHEDULE FOR THE TEST YEAR IN GRID?

A. No. The Company uses a "normalized" maintenance schedule, with outage durations based on a four-year average. Given that the planned maintenance schedule can be changed in response to forced outages and other events, and the four-year average outage rate may not coincide with actual outages planned for the test year, use of a normalized maintenance schedule is reasonable. However, I do not believe that the *schedule* input assumptions actually applied in GRID provide a reasonable representation of a normalized maintenance schedule. The figure below illustrates the problems with the planned outage schedule assumed in GRID.

Figure 3



Q. PLEASE EXPLAIN THIS FIGURE.

A. This graph shows the percentage of scheduled outage energy[19/] for each month of the calendar year due to planned outages based on the 48-month period that ended December 31, 2007. It is apparent from the chart that actual planned outages have traditionally been scheduled to coincide with the low market price periods in the spring and fall. April, May and June typically have the lowest market prices, and the Company traditionally has performed most of its maintenance (nearly 65%) during these months.

In contrast, the Company assumes in GRID that more outages will occur in the late winter months and in October. In the Company's test year, it is assumed 31% of scheduled outage energy will occur in February and March and 30% in October. While the Company has historically scheduled 65% of its planned outages in the low cost springtime months, the Company now assumes 67% percent of all outage energy will be scheduled in higher cost winter and fall months. If actually practiced by the Company, this would amount to imprudent operation in my view.

Q. WHY DO YOU USE THE FOUR YEARS ENDED DECEMBER 31, 2007 AS THE REFERENCE POINT FOR ACTUAL HISTORICAL OUTAGES?

A. The <u>duration</u> of planned outages in GRID is based on this four-year period. Therefore, the Company considers this period to define normalized results. For this reason it is a useful reference point to compare to the GRID planned outage schedule. I also have data on all PacifiCorp generator outages (planned and unplanned) going back to 1979. These data follow essentially the same pattern as

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19/ This would be the amount of coal-fired energy the Company would need to replace in order to make up the generation lost due to planned outages.

discussed for the four-year period. Historically, the Company seldom schedules planned outages for coal plants in winter months, and attempts to schedule as much as possible in the spring. Review of recent discovery for actual outages planned in the future confirms this pattern will prevail.

Q. HOW DOES THE COMPANY DEVELOP THE PLANNED OUTAGE SCHEDULE FOR GRID?

A. The approach actually used in GRID is an arbitrary and essentially mechanical process that and does not appear to be based on historical or expected outage schedules, market price curves or other scheduling considerations. The response to ICNU DR 1.6-1 provides the workpapers used to develop the schedule for planned outage in GRID. Included in those workpapers is a page called "Considerations" listing factors allegedly used by the Company in developing the planned outage schedule in GRID. These considerations are listed below:

Work crew availability - long lead times required for contractors generally can only work on one unit per plant hard to get workers during hunting season
Capacity on outage - in addition to system total, watch balance in transmission areas
Peak loads / High prices - avoid early July to mid September and late November to mid February
Sales in transmission constraint areas - for Cholla and UPL plants, avoid scheduling when delivering the APS Exchange (15 May to 15 September)
Open design / High altitude - avoid scheduling in cold weather for plants like Wyodak, Hunter, …
Single unit per plant - allow for delay in startup when scheduling another unit at same plant (expect when scheduling "normalized", which case schedule them back to back).
Co-owner / Co-generator - for Bridger, avoid IPC fall hydro season work around schedule for plants like Craig, Hayden, …coordinate with Fort James, GSLM, …
Non owned plants in control area - include plants like River Road, Bonanza, DG&T Hunter share in capacity outage totals don't schedule Hermiston at the same time as River Road
Unit contingent purchases include unit contingent purchases from plants like Sunnyside, San Juan Unit 4 in capacity outage totals

Weekend outages generally begin on Saturday or Sundays so parts are cooled by Monday (see above exception for "normalized")

Q. ARE THESE REASONABLE CONSIDERATIONS FOR THE SCHEDULING OF PLANNED OUTAGES?

A. Yes. On February 15, 2008 I discussed the process used to develop actual plant outage schedules with Mr. Mark Mansfield, PacifiCorp's Vice President of Operations Support and other Company personnel. Regarding the development of plant outage schedules, some of the above considerations were mentioned by the Company representatives. It should be noted, however, that the first thing mentioned in this meeting was that outages were scheduled in the spring (mid March to late May) to take advantage of low cost power in the market. It was also discussed that a second, though less preferable, window for outages occurs in the fall. As the historical data shown above indicates, the Company strongly prefers to actually schedule outages in the spring.

Q. HOW DOES THE COMPANY ACTUALLY APPLY THESE FACTORS IN DEVELOPING THE NORMALIZED OUTAGE SCHEDULE FOR GRID?

A. The actual application in GRID differs substantially from the items listed above. GRID essentially applies a mechanical process that does not actually apply market prices, or historical practice in determining the planned outage schedule to be used. As far as I can tell, the Company simply develops the schedule used based on an arbitrary and largely unexplained method. The Company appears to change the underlying assumptions form case to case. For example, in the recent Utah case, the Company proposed an outage schedule that showed coal plants going on maintenance in January and February. The Company contended in discovery responses that this was reasonable and, even in its rebuttal filing, proposed use of a schedule with coal plants on outage during those months. ICNU/115, Falkenberg/5 (Response to CCS DR 5.1 in Utah Public Service Commission Docket No. 07-035-93). While I have asked many discovery questions over the past year regarding this issue, the Company has never yet produced a reasonable explanation of its planned outage scheduling algorithm, nor justified its reasonableness. Id. at Falkenberg/5.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PLANNED OUTAGE SCHEDULE ISSUE?

A. I believe there is a very simple resolution to the matter. The Company bases its normalized outage energy requirements on the most recent four years of historical data (the 48 months ending December 31, 2007). I recommend applying each of the four actual schedules used during the four-year period in GRID. To do this I analyzed four distinct outage schedules for the one-year periods starting from 2004 to 2007. By computing the average cost of actual outages over the four-year period it will be possible to develop a power cost study that provides realistic normalized planned outages.

Q. ARE THERE OTHER ADVANTAGES TO THIS METHODOLOGY?

A. Yes. The use of the actual schedules is not subjective as compared to development of a schedule based on the GRID model criteria, or any other method. The data is readily available from PacifiCorp's response to ICNU DR 1.6-2 and easy to apply and interpret. The number of outage days and outage energy is the same for the normalized schedules and the actual four-year average. As the four-year average underlies the Company's planned outage requirements, this is a logical extension of the Company's methodology, which has been accepted by the Commission for many years. Finally, because all four of these schedules were actually used by the Company, there is no basis to suggest they were "result oriented" (i.e., solely designed to align with low market prices) impractical, infeasible or otherwise improper. The Company has typically made these sorts of unfounded criticisms in prior cases when its planned outage schedule was questioned.

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

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

Q. PLEASE PRESENT THE RESULTS OF THIS ANALYSIS.

A. The table below presents these results. The figures shown are compared to the Company's original schedule. The results demonstrate that the Company has overstated the cost due to planned outages in GRID.[20/]

Table 3 – Planned Outage Schedule Adjustment

	Actual Outages	**+ CC in Spring**	**CC Diff**
2004	18,134,346	19,187,910	1,053,565
2005	4,679,858	5,622,386	942,528
2006	-13,489,449	(12,674,875)	814,574
2007	10,163,374	10,256,765	93,391
Total	4,872,032	5,598,046	726,014

20/ This analysis is based on the median hydro base case. In Table 1 results differ slightly because it was applied after all other adjustments were implemented. The figures shown represent a reduction to NVPC when reported as a positive number.

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

A. Outages are scheduled on a cyclical basis. The low cost year (2004) was a period where relatively few planned outages were scheduled. The high cost period (2006) coincides with a period where more than the average amount of outage energy was scheduled. This table actually provides a good reason for normalizing maintenance instead of using a single year. The results can vary substantially from one year to the next based on the actual outage schedule. This is why the Company uses a four-year average to develop the amount of planned outage energy to include in the test year. I recommend the Commission adopt my methodology for computing the planned outage adjustment to be used in GRID and that it require the Company to use the four outage schedules I have developed.

V. GRID HYDRO MODELING

Q. BRIEFLY EXPLAIN THE HYDRO MODELING METHOD USED IN GRID.

A. GRID simulates three scenarios: Wet, Median and Dry. These are *assumed* by the Company to represent the 25^{th}, 50^{th}, and 75^{th} percentiles of the annual hydro energy distribution. The Company calls these the 25-50-75 "exceedance" levels. GRID computes power costs for each of these scenarios and takes the simple average of the three results to develop normalized net power costs.

Q. IS THERE A FUNDAMENTAL PROBLEM WITH THE MANNER IN WHICH THE COMPANY MODELS HYDRO RESOURCES IN GRID?

A. Yes. The Company greatly overstates both the severity and likelihood of the "wet" and "dry" hydro scenarios modeled in GRID. There are two fallacies in the Company's approach.

The first fallacy is that the Company assumes in creating the wet and dry cases, that all of the major river systems providing hydro resources to the Company are perfectly correlated with each other. This means that if the Mid Columbia river is having a "dry" year (25% exceedance level), so will all of the other river systems, including the Bear river which is hundreds of miles away. The Company also assumes that a wet or dry year is composed of 52 weeks of wet or dry conditions (the second fallacy). The first fallacy can be disproven by looking at actual annual stream flow data for the various river systems and measuring the correlation among these rivers.

Q. DESCRIBE YOUR EVIDENCE CONCERNING CORRELATION OF THE RIVER SYSTEMS.

A. The table below shows the actual correlation for annual energy generation from 1964 to 2003 for the five major river systems from which the Company obtains hydro energy. This data was obtained in discovery in the recent Utah rate case (Docket No. 07-035-93, CCS DR 2.3). The analysis shows moderately strong correlation between the Umpqua and Klamath rivers (p=.81), but only moderate to very weak correlation for the rest. In developing the wet, median and dry cases, the Company's method assumes *nothing less than perfect correlation among the river systems on an annual basis.* For this reason, the Company's method substantially overstates the probability and severity of the wet and dry cases.

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

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

Perhaps the most significant observations from the above data is that the Mid-C river system is quite poorly correlated to all of the other river systems. For example, for the most recent 12 month period, ending March 2008, PacifiCorp system hydro generation was 12% below normal, while Mid C was 7% above normal. This illustrates why it is unrealistic to assume perfect correlation across the river systems as the Company does in preparing the GRID inputs.

Q. IS THERE ANOTHER EXAMPLE THAT ILLUSTRATES WHY THE COMPANY'S ASSUMPTION THAT WET OR DRY CONDITIONS WILL OCCUR EACH WEEK OF THE YEAR (THE SECOND FALLACY) IS WRONG?

A. Yes. Assume one was trying to develop a "wet" or "dry" rainfall scenario for Portland. Portland is regarded as being rainy averaging about 150 days per year of measurable rainfall and 10 to 20 days per month. However, if one were to look at all of the years of recorded history, it would almost certainly be possible to find at least one year when it didn't rain in Portland during any specific week of the year. Put another way, it is quite unlikely that there is a single week, even in rainy Portland, where it has always rained in recorded history. Likewise, it is also reasonable to assume that over many years of history, one could always find a year where it did rain in a specific week. It is very unlikely that over many years, there is not a single week where it has never rained in Portland.

Q. HOW DOES THIS RELATE TO THE COMPANY'S SELECTION OF A WET (OR DRY) HYDRO SCENARIO?

A. Unfortunately, the Company's approach to selecting a wet scenario would be akin to assuming that it rains every week of the year in the wet case, because there was always some year in history when it did rain during that week in Portland. Likewise, the Company's approach to the dry scenario is akin to assuming that it never rains in Portland in the dry case (because one can always find at least one year where it didn't rain during any particular week).

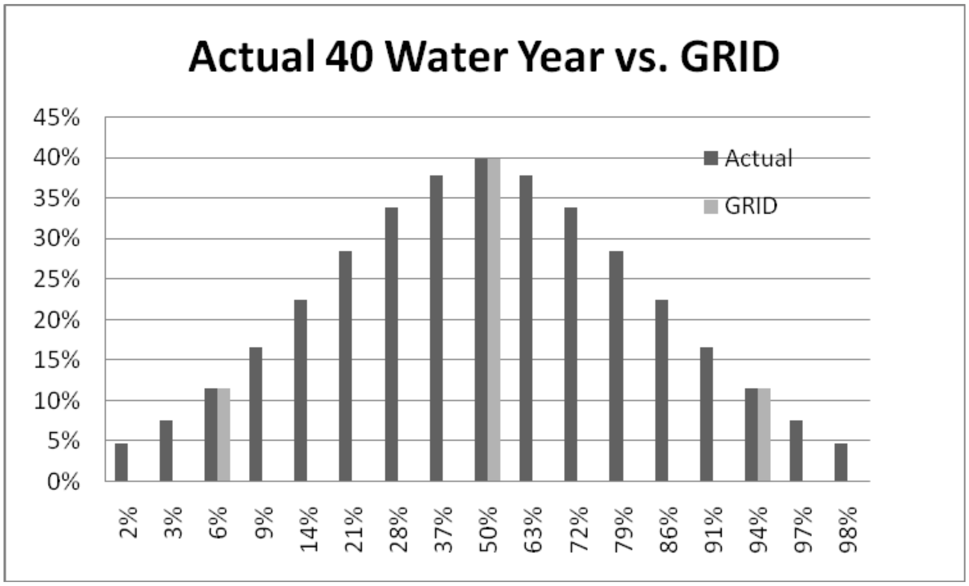
The logic behind the Company's wet case, would suggest that the wet scenario for Portland, would be a year where it rains every single week. This is because the Company would construct its wet scenario by combining the results for 52 wet weeks (just as it constructed the wet hydro case from 52 wet weeks – the second fallacy). I submit that a year where it rains every week is something that has never been recorded, even in Portland. Likewise, the Company's logic would suggest a dry scenario for Portland, where it never rained even during a single week.

The basic problem here is the assumption that a wet (or dry) case should be constructed by accumulating individual wet (or dry) weeks while ignoring the annual pattern of wet and dry conditions. The Company constructs its wet (or dry) hydro scenarios assuming that each <u>week</u> of the year experiences wet (or dry) hydro conditions. In reality, it never happens that way. Wet years are those where there are many rainy days or weeks, but no cases where it rains every single week. Even in the wettest years in history, it likely did not rain every single week. The same is true in the dry case.

The Company's approach ignores common sense and greatly exaggerates the severity of the wet and dry cases. This makes them very unlikely outcomes. In GRID, the Company assumes the wet and dry cases occur once every three years. The reality is much different. These wet and dry scenarios modeled in GRID may occur, but they are extremely rare events.

Q. DO YOU HAVE ANY EVIDENCE THAT DEMONSTRATES THE VISTA DATA USED IN GRID OVERSTATES THE SEVERITY AND LIKELIHOOD OF THE WET AND DRY HYDRO CONDITIONS?

A. Yes. I used data the Company prepared for GRID inputs to develop a complete forty water year history for the 1964-2003 period. This data was conformed to the Company's test year assumption for average hydro generation and compared it to the GRID data used in this case for the 25-50-75 scenarios in the chart below. The figure shows that rather than providing 25th and 75th percentile results, the wet and dry cases really amount to 6th and 94th percentile cases. This clearly demonstrates that the Company has greatly overstated the severity and therefore the likelihood of the wet and dry cases. Rather than representing one in three year events, the wet and dry cases represent one in seventeen year events.



Q. PLEASE EXPLAIN THE FIGURE ABOVE IN MORE DETAIL.

A. Based on the forty water years of data, the standard deviation for annual hydro generation was 843 thousand MW and the mean hydro was 5,999 thousand MWh for the test year. The wet case, 7,314 thousand MWh is 1.56 standard deviations above the mean, representing the 94th percentile. The dry case, 4,679 MWh is 1.57 standard deviations below the mean, representing only the 6th percentile of the overall annual hydro energy distribution. This differs substantially from the Company's assumed distribution, which would require that the dry case be only .68 standard deviations below the mean, and the wet case only .68 standard deviations above the mean. The true 25th percentile (dry) case is 5,278 thousand MWh, while the true 75th percentile (wet) case is 6,625 thousand MWh.

Q. IN UE 191 YOU PRESENTED ARGUMENTS AGAINST THE COMPANY'S MODELING OF HYDRO. THE COMMISSION REJECTED YOUR PROPOSAL. EXPLAIN WHY THE COMMISSION SHOULD CONSIDER A CHANGE TO HYDRO MODELING NOW.

A. The Commission didn't agree with my proposal to use the mean hydro. I acknowledge that the calculation of mean hydro I performed was criticized by the Company as being unrealistic. I no longer make that recommendation.

Ultimately, the Commission rejected my proposed adjustment on the basis that the Company had revised the model to eliminate the extremes. I suspect that I didn't do a good job of explaining the problem with the GRID hydro modeling, or perhaps the Commission may not have made that finding. In any case, the evidence I have developed here shows that the Company greatly overstates the severity of the wet and dry cases, which in turn overstates the likelihood of these events. On this basis, I suggest the Commission reconsider the issue.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THIS ISSUE?

A. My recommendations on this issue are twofold:

(1) The weights assigned to the wet and dry cases in GRID should not be equal to 1/3 (the same as the median case). These scenarios represent extreme events (only occurring a few times in years of history) that should not be considered as being likely to occur once every three years. The Commission should require the Company to develop the proper weights in the next case, if it continues to use the same 25-50-75 scenarios.

(2) The Commission should also require the Company to file a complete 40 water year study in its next TAM or general rate case proceeding. This would enable a comparison of the hydro modeling options in that case, and allow the Commission

to select the most proper method. I believe a proper 40 year hydro study would produce a lower NVPC than use of the Company's methodology applied to the same data. By requiring the Company to prepare a full 40 water year study it will be possible to decide this issue once and for all.

Q. HAVE YOU COMPUTED A HYDRO MODELING ADJUSTMENT?

A. Yes. Table 1 shows the results from using only the median hydro scenario. Based on my analysis, the median hydro result is not biased to the same degree as the wet and dry scenarios. I believe this provides a better approximation to the correct level of a proper hydro modeling adjustment, and use it as the basis for computing my other adjustments.

VI. THERMAL DERATION FACTORS

Q. EXPLAIN THE USE OF THERMAL DERATION FACTORS IN GRID.[21/]

A. In GRID, thermal deration factors (also called unplanned outage rates) control the amount of generation available from thermal units. The more energy available, the lower net variable power costs. If a generator has an average unplanned outage rate of 5%, GRID assumes a thermal deration factor of 95%. This means that only 95% of the unit's capacity is available to produce energy. The remaining capacity is assumed to be permanently unavailable.

21/ Hereafter in this testimony, unplanned outages and outage rates will be discussed, as distinguished from the planned outages discussed above. Even if the text doesn't specify it, I will be discussing unplanned outages.

Q ARE THERE ANY ISSUES REGARING OUTAGE RATE MODELING IN GRID?

A. Yes. The Company has three mistakes in computing the GRID input outage rates. Further, there are a number of other issues surrounding the Company's outage rate modeling the Company's techniques should be improved upon.

OUTAGE RATE COMPUTATION ERRORS

Q. HAS THE COMPANY CORRECTLY COMPUTED THE UNPLANNED OUTAGE RATES FOR CURRANT CREEK AND LAKESIDE?

A. No. Traditionally, the Company has used a 48 month rolling average to compute unplanned outage rates. In cases where new plants have come online, and there is less than 48 months of actual data, the Company has used a blend of historical data and generic outage rate data (generally obtained from the Integrated Resource Plan ("IRP")). While I believe it would be more appropriate to use data from the IRP without blending it with actual (due to the fact that new units have more outages than normal in the first few years), I won't challenge that aspect of the Company's calculation here. This issue may be better addressed in UM 1355.

In the case of Currant Creek and Lakeside, the Company did not use a blended average. In response to ICNU DR 4.6 and 4.7 the Company confirmed that it inadvertently left out the blending adjustment (as was used in UE 191). ICNU/115, Falkenberg/6-7. The effect of correcting this oversight is shown in Table 1. I optimistically assume that the Company will agree to actually implement this correction. Whether it does or not, I recommend the Commission adopt it.

Q. ARE THERE ANY OTHER PROBLEMS WITH THE OUTAGE RATE MODELING IN GRID?

A, Yes. The Company now includes an adjustment for "ramping" in its modeling of outage rates in GRID. Ramping is intended to account for generation below full loading of a resource after a shutdown. Because ramping was withdrawn by the Company in UE 170, not applied in UE 191, and because it was a contested issue resolved by settlement in UE 179, I believe there is no actual precedent for including ramping in this case (or in any other state either). Further, the Washington Commission rejected the Company's ramping proposal in the last case in that state. As I will discuss later, I propose removal of the entire ramping adjustment proposed by the Company. However, to delineate that portion of the ramping issue from one which I believe to be far less controversial, in this portion of the testimony I will address only one aspect of the Company's ramping adjustment which it has already admitted is incorrect.

Q. PLEASE EXPLAIN.

A. Exhibit ICNU/107 shows that when the Company's ramping methodology was applied in the case of Gadsby units 3, the Company's ramping methodology greatly overstated the amount of lost energy because it counted energy lost to reserve allocations as being energy lost due to ramping. This is clearly erroneous. This analysis, which will be discussed in more depth shortly, was an exhibit I filed in the current Utah case.

Q. DID THE COMPANY RESPOND TO THIS ANALYSIS?

A. Yes. Mr. Duvall admitted in the Utah proceeding that the Company had overstated the impact of ramping on its outage rates at least, for these gas-fired units:

> …[T]he Company agrees that its current ramping calculation could inadvertently cover a gas plant being held for reserves. To adjust for that possibility, the Company agrees to remove the Gadsby units from the ramping adjustment[22/].

I recommend that, as a minimum, the Commission reduce the ramping adjustment to remove the ramping on the Gadsby steam units from GRID. This adjustment is included in the Equivalent Forced Outage Rate ("EFOR") Error Correction Adjustment shown in Table 1. This is consistent with the Company's admission in Utah, and I optimistically assume the Company will not object to it in this case. Irrespective of the Company's position, I recommend the Commission adopt this adjustment.

Q. ARE THERE ANY OTHER OUTAGE RATE ERRORS?

A. Yes. The Company differentiates outage rates between weekend and weekdays. The Company assumes the weekend outage rate should be applied for 56 hours, starting at 10 pm every Friday night. However, the outage rate is actually calculated based on a 48 hour long weekend period starting at 12 am Saturday. The Company acknowledged this mistake in ICNU 8.1. ICNU/115, Falkenberg/8. This correction is also included in the EFOR Error Correction Adjustment shown in Table 1.

Q. PLEASE DISCUSS THE REMAINING OUTAGE RATE ISSUES.

A. In the following sections of my testimony, I address issues related to the Company's modeling of outage rates in GRID. These issues are reflected in the EFOR Other Adjustments line in Table 1. While I believe all of these

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[22/] Re Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates, Utah Public Service Commission Docket No. 07-035-93 at 21 (Rebuttal Testimony of Gregory N. Duvall).

adjustments should be made, I have differentiated them from the prior series of adjustments because they do not represent corrections to EFOR calculations that fix errors that the Company has already acknowledged.

MONTHLY OUTAGE RATES

Q. HOW DOES THE COMPANY MODEL UNPLANNED OUTAGE RATES IN GRID?

A. The Company differentiates unplanned outage rate on a monthly basis using the average monthly outage rate computed from the four-year period ending December 31, 2007. Only the Washington Commission has ruled on use of monthly outage rate modeling, deciding against this new procedure in the most recent case in that state.[23/]

Q. IS THIS AN INDUSTRY STANDARD PRACTICE?

A. Most definitely not. PacifiCorp's approach is quite unusual and certainly not industry standard. While I am aware that a few utilities have briefly experimented with modeling seasonal outage rates, the vast majority of utilities assume a constant outage rate throughout the year. The primary reason for this is that there are few physical factors affecting thermal power plant operation that would result in outage rates varying significantly on a monthly or seasonal basis. There is really no engineering or statistical basis to assume a generating unit would be significantly more reliable in January than July, for example. In the absence of any supporting data, use of monthly outage rates by the Company amounts to little more than guesswork.

23/ WUTC v. PacifiCorp, Docket No. UE-061546, Final Order at 35-36 (June 21, 2007). I do acknowledge the WUTC order is rather unclear on this issue, however, in its most recent filing in Washington (Docket No. UE-080220), the Company excluded both its ramping and monthly outage rate adjustments based on that order. Id.

Q. DOES THE COMPANY'S PROPOSED MONTHLY OUTAGE RATE MODELING INCREASE OR DECREASE NVPC?

A. In this case, it produces a decrease in NVPC. However, given the lack of a sound engineering basis, statistical data or common sense argument supporting it, I believe the Company's approach should be rejected. Accordingly, I recommend that the Commission reject the monthly modeling of outage. This adjustment is reflected as part of the outage rate modeling adjustment shown in Table 1.

THERMAL RAMPING

Q. PLEASE PROVIDE SOME BACKGROUND CONCERNING THE RAMPING ISSUE.

A. To implement its ramping adjustment, PacifiCorp creates "phantom outages," inflating its outage rates for thermal units above actual values for the four year period. The Company first proposed this technique in UE 170 motivated by an assumption that GRID was producing an excess of coal-fired generation.[24/] Recent actual results show that GRID substantially underestimates coal-fired generation. For example, in the 12 months ended March 31, 2008 the Company's coal plants produced 46,319 thousand MWh. In the GRID test year, only 45,108 thousand MWh of coal generation is included.

The Company withdrew the adjustment in UE 170 in one of the partial stipulations in that case. In UE 179, the Company proposed a ramping adjustment, but that case resulted in a settlement on net power costs issues which resolved, but did not address the issue of ramping. Subsequently, power costs issues were settled in other states in cases involving the issue and no decision on

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[24/] Re PacifiCorp, OPUC Docket No. UE 170, Exhibit PPL/604, page 2 (Supp. Direct Testimony of Mark Widmer).

ramping was issued by any state regulatory commission. Finally, in Docket No. UE-061546, the Washington Commission rejected the ramping adjustment proposed by the Company. The Company did not include this adjustment in its most recent prior Wyoming and Oregon cases (UE 191) which followed on the heels of the Washington case.[25/] In the end, the thermal ramping issue has not been decided by the OPUC, though the Commission rejected an *eerily similar phantom outage adjustment* proposed by PGE in UE 139.[26/] Nonetheless, the Company proposed to apply it in this case. Further, it was clearly not applied in UE 170 or UE 191, and because of the settlement in UE 179, there is no basis to assume the ramping adjustment has ever been included in any prior case in Oregon.

Q. IS MODELING OF THERMAL RAMPING IN THE MANNER USED BY THE COMPANY STANDARD INDUSTRY PRACTICE?

A. No. Based on my nearly thirty years of experience working with various power cost models, this approach is extremely unusual and contrary to standard industry practice. The North American Energy Reliability Council ("NERC") publishes a standard formula for computation of forced outage rates, and the approach proposed by the Company does not use the NERC formula.

Q. CAN YOU ILLUSTRATE SOME OF THE PROBLEMS WITH THE COMPANY'S RAMPING ADJUSTMENT?

A. Yes. Refer again to Exhibit ICNU/107. This shows the Company's calculation of the ramping adjustment for Gadsby Unit 3 for the month of March, 2007. The worksheet shows how the ramping calculation is performed each hour. The

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25/ The Company has stated elsewhere that the ramping adjustment was left out by mistake, though the timing is certainly curious**.**

26/ Re PGE, OPUC Docket No. UE 139, Order No. 02-772 at 23-24 (June 7, 2002).

Company's methodology assumes that <u>any</u> difference between the actual loading of a unit after it has been started up and 90% of its available capacity is due to ramping. This is a very significant adjustment for Gadsby Unit 3 in the calculation of March outage rates because this is the only March during the four-year period ending December 31, 2007 when Gadsby Unit 3 was actually called upon to run. In total, the unit generated 916 MWh during that month, *but lost 994 MWh due to ramping*.

Q. PLEASE MORE FULLY DESCRIBE THE PROBLEMS WITH THE COMPANY ANALYSIS.

A. The first problem is that the Company assumes that unless a unit is running at 90% of its full loading, it must be losing generation due to ramping no matter how long it has been running or whatever other circumstances might exist. In the Gadsby Unit 3 example, on March 28, 2007, the Company assumes that even after the unit ran for <u>eleven</u> hours (when the unit is cycling down to a reserve shutdown), it was still losing energy due to ramping. In the last hour of operation on that day, the unit produced only 5 MW (as compared to available capacity of 100 MW). The Company assumes this resulted in 95 MW lost due to ramping, even though it acknowledged in a data response that the unit was only online part of the hour and heading into reserve shutdown status.[27/]

This is a very flawed approach, however, because there is no basis for the assumption that the unit would otherwise be dispatched to at least 90% of its full loading if not for ramping. The real time dispatch may determine, for example,

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[27/] Exhibit ICNU/107.

that the most economic dispatch is something less than full (or even 90% of full) loading for a unit.

Alternatively, the unit may be assigned to carry reserves. Exhibit ICNU/107 also shows the hourly allocation of reserves to Gadsby Unit 3 during March 2007. It shows that the unit was assigned to carry reserves every single hour when the Company assumed it would otherwise be losing generation to ramping. In this example, 487 MWh which the Company assumed to be lost due to ramping was actually assigned to reserves. This amounts to almost half of the ramping adjustment for the month. The fact that the unit had so much capacity allocated to spinning reserves clearly indicates that it was never intended to run at full loading. Instead it was started to provide reserves and therefore operated at much less than full load. Under the Company's analysis of ramping, all of this was ignored. Were these facts considered, virtually none of the lost ramping energy should be counted.

Q. AS DISCUSSED ABOVE, IN THE RECENT UTAH CASE, MR. DUVALL AGREED RAMPING SHOULD NOT BE APPLIED TO THE GADSBY UNITS. HE PROPOSED TO INCLUDE RAMPING FOR OTHER UNITS. DO YOU AGREE WITH HIS PROPOSAL?

A. No. First, while the analysis of ramping presented in Exhibit ICNU/107 examined only one of the Gadsby units, it should not be inferred that this problem applies *only* to these units. Many of the problems that resulted in an obvious overstatement of ramping lost energy would apply to any type of unit. Many of the Company's thermal units are required to supply reserves from time to time, and/or experience deration events that would be counted as ramping in the Company's flawed methodology. Further, the Company should limit ramping energy to only that occurring in the period of time required to start the unit and bring it to its dispatch level.

Given the problems with the concept, the Company's admission that it is incorrect, and lack of precedent supporting it, I recommend the Commission reject the ramping adjustment in its entirety. I recommend instead the Commission investigate this issue in UM 1355. Reversing the Company's proposed ramping adjustment is included in my Table 1 as part of the outage rate modeling adjustment.

DEFERRABLE MAINTENANCE

Q. DISCUSS THE HISTORY OF MODELING OF DEFERRED MAINTENANCE IN PACIFICORP'S OUTAGE RATE CALCULATIONS.

A. Prior to UE 170, the Company included all deferrable outages in the weekend outage rate. During UE 170, the Company proposed an "update" to its NPC study that changed the calculation of the weekend outage rate to reflect only the lost generation occurring during the weekend.[28/] In the Third Partial Stipulation in UE 170, the Company agreed to withdraw the adjustment. The Company did include its new weekend outage rate modeling approach in UE 179, and UE 191, however. The former case was settled, and the issue was not litigated in the later case. I recommend the Commission address the issue at this time, since it has made no decision concerning the matter.

28/ It was at that time that the error related to the 56 vs. 48 hour weekend outage period discussed was introduced by the Company. In the previous calculation of weekend outage rates, deferrable outages were spread over a 56 hour period. Subsequent to that, the Company computed weekend outages based on the actual lost energy in a 48 hour period, but continued to apply it to 56 hours. This error has been perpetuated for several years now.

Q. WHAT IS DEFERRABLE MAINTENANCE?

A. NERC defines maintenance outages as those outages that can be deferred to beyond the next weekend, but not longer than until the next planned outage. Under the NERC formula, maintenance outages are not considered part of the forced outage rate. As discussed above, prior to UE 170, the Company modeled maintenance outages as part of a weekend outage rate. While this is not a "perfect" solution, it captures the likelihood that such outages could be deferred to a more advantageous time (i.e., periods when lower market prices prevail).

Q. WHY DO YOU RECOMMEND THE COMMISSION RETURN TO THE PRIOR METHOD OF REFLECTING DEFFERABLE MAINTENANCE?

A. Because these types of outages are deferrable, it is unreasonable to include them as part of the weekday forced outage rate. When they are included in that manner, they reduce generation during all hours, both peak and off peak. In reality, such outages can be deferred until times when market prices are more favorable. For example, if such a problem requiring a maintenance outage were to occur during a summer heat wave, plant managers could defer the repairs until night time, a period of milder weather (and lower market prices) or at least until the next weekend. In any of these cases, lower market prices would prevail, and the cost of the outage would be lower. The Company ignores this and proposes to include much of the deferrable maintenance energy during weekday, on-peak periods. I recommend the Commission recognize that modeling deferrable maintenance outages in the weekend is the best approach for recognizing the cost minimizing actions of a prudent utility. This adjustment is also included in the outage rate modeling adjustments shown in Table 1.

VII. GENERATING UNIT REPRESENTATION IN GRID

Q. EXPLAIN HOW GENERATOR OUTAGES ARE REPRESENTED IN GRID.

A. As discussed earlier, GRID uses what is known as the deration method to model outages. Outage rates are assumed to reduce the available capacity. This means that if a unit has 100 MW of capacity, and a 5% outage rate, the unit is represented in GRID as a 95 MW unit that is available 100% of the time. This is an industry standard technique. Though dated, this approach has been used in various models for many years. In effect, GRID replaces the capacity of each unit with its "expected value." The expected value, MW_e, for a unit is computed as shown below:

MW_e = MW x (1-EFOR), where EFOR = the outage rate of the unit, and MW is the maximum capacity of the unit.

The above formula is appropriate because it represents a situation where the unit is fully available (i.e., to MW, the maximum capacity) (1-EFOR)[29/] percent of the time, and available at zero MW (because it is on an outage) EFOR[30/] percent of the time.

I have no objection to this representation in GRID, even though there are other, more sophisticated, methods (such as Monte Carlo modeling that may provide more realistic simulations). While it is not immediately obvious, proper use of the deration method also requires other adjustments to unit characteristics be made as well. First of all, the unit *minimum capacity*, MW(min) should also be

[29/] 95% in the example above.
[30/] 5% in the example above.

derated in the same proportion as the *maximum capacity*. The expected value of the minimum capacity, $MW(min)_e$ is given by the formula below:

$$\mathbf{MW(min)_e = MW(min) \times (1\text{-}EFOR).}$$

The simple and intuitive explanation is that unless this adjustment is made, the unit's *minimum* capacity could exceed its *maximum* capacity. While this may seem far fetched, it actually did happen in some situations in the GRID simulations for the test year. This illustrates a serious problem in the Company's modeling.

A more detailed and mathematical explanation is that when simulating operation at minimum loadings, it is also necessary to compute the expected value of the loading. If the unit is expected to be operating at minimum loading during a given hour, the expected value of its generation is MW(min) 1-EFOR percent of the time, and zero EFOR percent of the time. This is no different than the case discussed above involving maximum capacities. While the Company derates the maximum capacity for outages in GRID, it does not do so for the minimum capacity. Given the substantial number of resources now operating at minimum loading, this has become a very serious oversight.

Q. CAN YOU PROVIDE A SIMPLE EXAMPLE SHOWING WHY THIS ADJUSTMENT IS NECESSARY IN GRID?

A. Yes. Assume a hypothetical situation where a generator is dispatched at 10 MW for a 100 hour period. In this case, it would generate 1000 MWh. Now, however, assume the unit was on forced outage half of that 100 hour period. In that case, it would only generate 500 MWh and have an outage rate of 50%.

If the unit has 10 MW maximum capacity GRID would treat it as a 5 MW unit running for all 100 hours. This is the way in which the derate model works. In that case, GRID would show it producing 500 MWh, and it would produce a realistic result.

Now, however, assume that the unit was really a 50 MW unit, with a 10 MW minimum. In that case, GRID would show it having a maximum capacity of 25 MW and a minimum capacity of 10 MW because it would derate the maximum capacity for outages (50%) but not do so for the minimum capacity. In this case, GRID would show the unit running at minimum capacity all 100 hours, producing 1000 MWh, or twice the correct amount. Clearly, this problem must be fixed in GRID for results to be realistic.

Q. IS THIS THE ONLY ADJUSTMENT REQUIRED?

A. No. There must also be a corresponding adjustment to the heat rates, which is not being done in GRID either. Generating units are represented in GRID using a polynomial heat rate equation:

$$\textbf{Heat input (hour h)} = \mathbf{A+B \times MWh+ C \times MWh^2}$$

Here MWh is the loading of the unit in hour h.

If, for example, the unit is expected to be running at its maximum capacity, GRID will treat it as a smaller unit running at less than full load. Returning to the original example of a 100 MW unit, GRID sees it as a 100 MW unit that is only running at 95 MW. In this case, the actual heat input of the unit will be overstated, because units are generally most efficient at their full loading point. The heat rate curve used in GRID will therefore overstate fuel costs.

This is again related to the concept of expected value. The expected value of the heat input for the 100 MW unit is as follows:

Heat input = (A+B x 100 + C x 100^2) times 95% + 0 times 5%.

In effect, the above equation shows that the expected value of the heat input should be computed as (1-EFOR) times the heat input at full loading. GRID, however, would compute the heat input as shown below:

Heat Input (GRID) = A+B x 95 + C x 95^2

While it appears to be a rather minor adjustment in the case where a unit is fully loaded, it can be very important in some cases. Further, because unit efficiencies typically decline as unit loadings decrease (moving down the heat rate curve), ignoring this adjustment will increase NVPC. Even worse, not making this type of adjustment could produce absurd results in some cases.

Q. WHAT FURTHER ADJUSTMENT IS NEEDED?

A. In this case, it is necessary to adjust the heat rate curve so that it produces the same heat input at the derated maximum and minimum capacities, as the unit would actually experience in normal operation. The proper adjustment to the heat rate curve is as shown below:

Heat Rate Curve Adjusted = A x (1-EFOR)+B x MWh+ C/(1-EFOR) x MWh^2

Q. ARE THESE MODELING TECHNIQUES APPLIED BY PGE?

A. Yes. In its Monet model, PGE applies the very type of technique I am proposing. Exhibits ICNU/108, ICNU/109 and ICNU/110 show data responses from UE 197, confirming this fact.

Furthermore, PacifiCorp itself actually applies the same technique for fractionally owned units. Ultimately, there is no reason why the Company should be allowed to overstate power costs due to its lack of accurate modeling techniques.

Q. PLEASE PROVIDE AN EXAMPLE ILLUSTRATING THIS PROBLEM.

A. For May 2009, for Currant Creek the Company assumes an outage rate of 50%. Applying that outage rate in GRID reduces the maximum capacity of the plant to around 210 MW. This is far less than the assumed minimum loading for the plant (340 MW), and results in an average heat rate for the unit of 9,196 BTU/KWh for the month. This result is far more than would normally occur for the plant in conventional operation (which typically averages well below 8,000 BTU/KWh). This problem clearly stems from the unrealistic modeling of the unit with a large outage rate without making any corresponding adjustment minimum loading levels or the unit's heat rate curve.

Q. HAVE YOU PREPARED AN EXHIBIT THAT PROVIDES A MORE DETAILED ANALYSIS JUSTIFYING THESE INPUT CHANGES TO GRID?

A. Yes, Exhibit ICNU/111 presents an example and a detailed explanation of it that further demonstrates why these adjustments are necessary. It shows that unless these adjustments are made, GRID will overstate NVPC. The values for these corrections are shown in Table 1.

VIII. OTHER ISSUES

Q. DOES GRID SIMULATE ALL OF THE TRANSMISSION RESOURCES AVAILABLE TO THE COMPANY?

A. No, the Company ignores available non-firm transmission resources. The Company contends it should not include non-firm transmission because it is "*not known-and-measurable under normalized rate-making*." ICNU/115, Falkenberg/9. Instead, the Company represents only firm transmission rights in GRID as is shown on the Company's response to ICNU DR 1.3-1.

Q. WHAT ARE THE IMPLICATIONS OF EXCLUDING NON-FIRM TRANSMISSION?

A. First of all, the transmission flows modeled in GRID will be quite different from those that actually take place and the two are not comparable. This implies that the distribution of generation among the Company's resources may be quite different from actual results as well. In effect, the Company is divorcing the actual operation of the system from its normalized modeling results in GRID. In this, and many other instances, the Company's approach to GRID actually deviates from the intended purpose of normalization.

Q. IS THIS REASONABLE?

A. No. It is not known exactly what non-firm transmission will be available to the Company during the Test Year. However, the same is true of nearly any other input in GRID. For example, market availability and the price for non-firm balancing power are not known either. For that matter, we do not know what customer loads will be, what unplanned generator outages will occur, or what fuel costs will be. Despite this uncertainty, the Company performs power cost studies with GRID using historical data as a guide to prepare inputs and (at least in theory) make sound choices about each and every data input. It makes no sense to perform highly detailed projections of the generation system using hundreds of thousands of data inputs, yet ignore a vital element of the resources available.

Further, excluding non-firm transmission will certainly serve to increase NVPC because, like market purchases, the Company need only avail itself of these resources when they enable cost savings. The lack of non-firm transmission capacity may also result in certain constraints arising in GRID, which may not exist in real-time operations. Failure to model non-firm transmission presents a source of systematic bias in GRID, and limits the usefulness of comparisons of GRID results to historical data.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A. I recommend the Commission implement a non-firm transmission adjustment to GRID based on the use of four years of non-firm transmission flows and associated average charges. This data was obtained from PacifiCorp's response to ICNU DR 1.72. The amount of the associated adjustment is shown in Table 1. This adjustment is quite conservative, because I only used the average flow for specific links over the four year period. Because there were likely many times when these links were not used, use of an average figure likely understates the amount of non-firm capacity available on a day-ahead basis. Nonetheless, this provides a starting point for modeling of non-firm transmission.

Q. HAVE OTHER REGULATORY COMMISSIONS REQUIRED THE COMPANY TO MODEL NON-FIRM TRANSMISSION IN POWER COST STUDIES?

A. Yes. In an avoided cost case, Docket No. 03-035-14, the Utah Commission required the Company to start calculating avoided costs using a 48 month history of non-firm transmission.[31/] I used the same approach and data for my recommended adjustment in this case.

SP15 AND CAL ISO WHEELING EXPENSE

Q. ARE THERE ANY OTHER TRANSMISSION WHEELING EXPENSE ADJUSTMENTS THAT NEED TO BE MADE?

A. Yes. The Company models some transactions in the SP15 transmission area in GRID, though it has no firm transmission links connecting SP15 to the rest of the system. At one time, the Company had a 200 MW sale to Southern Cal Edison ("SCE"), but that is no longer the case. The Company's trading activities in SP15 require it to incur more than $10 million per year in wheeling expense from the Cal ISO.

Q. HAS THE COMPANY EXPLAINED WHY IT TRADES SP15 WHEN IT HAS NO LOAD IN THAT AREA?

A. I inquired about this in discovery. At present the Company transacts short-term firm products in SP 15, as part of a hedging strategy. These transactions are either purely financial, or may involve non-firm or day ahead wheeling between SP15 and other markets. A general point made in the various data response answers is that these hedging activities are not normally tied to very short term strategies. For example, in the response to ICNU DR 2.2, the Company states that trades made at SP15 are undertaken to hedge financial exposure at Four Corners at times when the Company believes the Four Corners market is illiquid. ICNU/115, Falkenberg/10. At times closer to delivery, the Company may sell at

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31/ Re PacifiCorp, Report and Order, Utah Public Service Commission Docket No. 03-035-14, at 14 (October 31, 2005).

Four Corners and buy at SP15, or the Company may wheel physical power on an hour ahead basis from Four Corners to SP15.

In the response to ICNU DR 4.16 the Company indicates that the decision to wheel power from Four Corners to SP15 vs. transacting at SP15 is made on a day-ahead basis. ICNU/115, Falkenberg/11. As a result, it should be clear that the decision to utilize SP15 is made very close in time to the delivery closing of physical or financial positions.

Q. WHAT ARE THE IMPLICATIONS OF THIS FOR TEST YEAR RATEMAKING?

A. I believe there is a serious problem in that the benefits of the Company hedging strategy cannot be realized in a test year prepared up to 13 months in advance of the ultimate transactions. In the GRID test year, the Company has taken a very unbalanced, long position at SP15. In the model, all these positions are closed out at the SP15 forward curve market prices. As a result, it is largely a matter of chance as to whether GRID will show a benefit or a detriment from these activities. Further, as the Company admitted in the response to ICNU DR 4.10, the objective of hedging is not cost minimization but rather a risk management strategy. ICNU/115, Falkenberg/12. Under current modeling methods, in the absence of non-firm transmission in GRID, and lacking any real connection between the Company's current long position in SP15 and its ultimate closing of those positions, I see no way in which ratepayers can benefit from this activity. Were this simply a cost neutral exercise, that would be a minor concern. However, the Company is expecting ratepayers to foot the bill of more than $10 million per year for Cal ISO wheeling fees to enable its hedging strategy to work.

I believe that is too high of a price to pay for something that cannot provide actual ratepayer benefits. Further, because the cost of the strategy as modeled in GRID will depend on the forward price curve (and there is no connection between the SP15 market and others in GRID), it will not afford ratepayers any benefit in terms of reducing price volatility. As a result, I recommend that, if the Commission decides against modeling of non-firm transmission in GRID, then it should remove all of the costs and transactions modeled in SP15 instead. The impact of this adjustment is shown in Table 1.

WIND INTEGRATION EXPENSE

Q. HAS THE COMPANY MODELED WIND INTEGRATION COSTS IN GRID?

A. Yes. The Company includes reserve requirements equal to 5% of online wind capacity for contingency (spinning) reserves. It has also modeled an additional cost of approximately $1.1/MWh, based on an analysis contained on page 193 of Appendix J of the PacifiCorp 2007 IRP. ICNU/116, Falkenberg/6.

Q. DO YOU AGREE WITH THIS APPROACH?

A. No. Review of the workpapers supporting the IRP wind integration analysis casts serious doubt on the Company's assumptions. In the IRP, the Company states that wind generation will not cause a need for contingency reserves (which are already modeled in GRID), nor will it cause a need for increased regulating margins. ICNU/116, Falkenberg/4-6. Because of the high reliability of wind generators, and the multiplicity of units, there is little need to increase contingency reserves for wind generation. As a result, the only wind integration cost referenced in the IRP was for hour to hour forecast uncertainty, which is expected to increase as the amount of wind generation on the system increases. As a result, I see no basis for including both the external wind integration cost of $1.1/MWh and the 5% contingency reserves already being modeled in GRID.

Further, the Company did not correctly apply the IRP findings to GRID and the IRP analysis contains errors. Page 192 of Appendix J to the IRP shows that the additional reserve requirements for the Company's planned 2000 MW wind portfolio is equivalent to an increase in reserve requirements of 43 MW. ICNU/116, Falkenberg/5. However, during the test year the Company will have approximately 1200 MW of wind capacity installed. The figure on page 192 of the Appendix J shows that for 1200 MW of wind capacity installed, the incremental reserve requirement is less than 10 MW. Id. Unfortunately, very late in the Utah case, the Company informed me that the IRP chart is wrong, and a more correct figure has been provided by the Company. The corrected figure is 23 MW for 1200 MW of additional wind generation.

The formula shown on page 192 of the IRP shows that if the lower reserve requirement is inserted into the equation, much lower wind integration costs result than assumed in GRID. Id. However, a further problem is that the wind integration cost figures as stated in the IRP workpapers apply only to the years 2012 to 2017, because the data for years prior to that was viewed as unreliable in the IRP workpapers. As a result, the Company simply has failed to provide *any* reasonable analysis of wind integration costs.

Q. HOW DO YOU RECOMMEND WIND INTEGRATION BE MODELED IN GRID?

A. It is not reasonable to include both the contingency reserves in GRID and the incorrect and overstated costs of reserve requirement external to the model. I modeled additional reserves in GRID for wind generation of 23 MW based on the IRP workpapers. However, I recognize that there may be other wind integration costs not considered in this approach. If the Company is able to identify and quantify these in its rebuttal case, I will carefully consider them.

Q. IS THERE ANY OTHER REASON TO CHANGE THE WIND INTEGRATION COST ESTIMATE IN GRID?

A. There is currently a settlement agreement in BPA's pending transmission rate case that contains a provision to institute a new charge for integration that may impact the Company. ICNU agrees that, if the BPA settlement is approved, any incremental wind integration charges resulting from the BPA tariff should be reflected in the final TAM update.

CAL ISO FEES

Q. DO YOU AGREE WITH THE COMPANY'S METHOD FOR ESTIMATING CAL ISO FEES?

A. No. The Company bases the Cal ISO charges on the average of actual charges over the last six months of 2007. For nearly all other transmission contracts the Company used the corresponding month from 2007 as the basis for computing the 2009 wheeling expense. For example, for most contracts, January 2009 was based on January 2007 costs plus escalation, if applicable. For Cal ISO charges, the Company did not follow this procedure but instead used a more recent six month average.

Q. WHY DO YOU DISAGREE WITH THIS APPROACH?

A. Comparison of the first 3 months of 2008 alone shows that the Company has overstated the Cal ISO fees by more than $900,000. While I wouldn't disagree with using a different estimation method in a case where a known change in the cost occurred, in this case, the data does not support making a change in the method. As a result, I recommend using the same method to compute Cal ISO fees for 2009 as the Company applied for nearly all of the dozens of other contracts. This adjustment is included in Table 1.

TRANSMITION IMBALANCE CHARGES

Q. EXPLAIN WHY TRANSMISSION IMBALANCE CHARGES SHOULD BE REFLECTED IN GRID.

A. I recommend reflecting the benefit of transmission imbalance charges the Company collects from third party customers in GRID. Under the Company Open Access Transmission Tariff, the Company charges third party customers when their load exceeds resources or their load is less than resources. The imbalance charges are discounted below or marked up above the market price depending on whether the imbalance results in a purchase or sale. In the end, this amounts to a low cost source of energy for the Company, which it has not reflected in GRID. Since these imbalances are treated as short-term firm transactions for actual cost reporting, they should also be reflected in GRID. Exhibit ICNU/112 is a copy of Wyoming Industrial Energy Consumers ("WIEC") DR 5.3 from the current Wyoming Power Cost Adjustment Mechanism ("PCAM") docket explaining this issue in more detail. I quantified this adjustment based on data for the 48 months ended December 31, 2007 consistent with the modeling of station service and other types of adjustments in GRID.

MINIMUM FILING REQUIREMENTS

Q. WHY DO YOU RECOMMEND THE COMMISSION ADOPT MINIMUM FILING REQUIREMENTS?

A. There is limited time to process TAM cases as well as general rate cases. In order to provide parties with sufficient time to fully address net power cost issues, I recommend the OPUC adopt minimum filing requirements ("MFRs"). This will afford a more efficient, and perhaps, less contentious discovery process, and provide for less time-stress on all parties. This is not an uncommon practice. For example, in Georgia, the Georgia Commission recently began utilizing MFR's as part of fuel factor cases. In Texas, MFRs have been required for many years. Utah also requires filing of certain Minimum Data Requirements with a general rate case, though the usefulness of these is limited by the fact that they are not filed until sometime after the case is filed.

Q. PLEASE DESCRIBE EXHIBIT ICNU/113.

A. This exhibit provides my recommended MFRs for the initial filing. These are items that are normally requested as part of ICNU's first data requests in the proceeding. I recommend the Commission require the Company to file this at the same time as it files a TAM or general rate case application. These MFRs are especially important for the TAM cases because the procedural schedule is abbreviated. The shortened schedule makes it very difficult to fully investigate the Company's case. I am required to conduct the same analysis on NVPC issues that I would perform in a general rate case, but in a significantly shorter period of time and a very limited opportunity to submit any rebuttal testimony.

Q. PLEASE DESCRIBE EXHIBIT ICNU/114.

A. This exhibit provides MFRs for all update, rebuttal or surrebuttal filings. It would be applicable to all parties, including ICNU. These would be due at the time of parties filing rebuttal, surrebuttal, and or any NVPC updates. Some of this data is already routinely provided by the parties when they do their filings, but it would be more efficient to have a specific set of requirements for future cases.

Q. ARE THERE ANY OTHER ASPECTS OF THIS ISSUE?

A. Another problem concerns confidentiality of data. In recent proceedings, PacifiCorp has designated a significant amount of information as confidential that that the Company previously made publicly available. This includes the GRID model and many of its inputs and outputs. While I believe the Company is over designating information as confidential, the practical impact is that ICNU's review of the Company's filing must now be delayed until I can obtain access to this confidential information. In particular, Oregon utilities have not always provided necessary data because the Commission has not approved a protective order. It may take some time for a protective order to be granted, which delays the time when parties may receive the necessary information. For major rate cases or for routine filings, (such as the TAM) this is completely inexcusable.

Utilities certainly know well in advance that they will be filing these cases. In such cases, Oregon utilities should be required to make arrangements with attorneys and experts in advance of their filings, so that parties can execute confidentiality agreements so that they may obtain the confidential data in the MFRs at the time of the filing.

Hopefully ICNU can reach an agreement with PacifiCorp and the other parties in this proceeding to resolve this problem. If a satisfactory resolution cannot be reached with PacifiCorp on this issue, then ICNU will propose specific remedies in its legal briefs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

EDUCATIONAL BACKGROUND

I received my Bachelor of Science degree with Honors in Physics and a minor in mathematics from Indiana University. I received a Master of Science degree in Physics from the University of Minnesota. My thesis research was in nuclear theory. At Minnesota I also did graduate work in engineering economics and econometrics. I have completed advanced study in power system reliability analysis.

PROFESSIONAL EXPERIENCE

After graduating from the University of Minnesota in 1977, I was employed by Minnesota Power as a Rate Engineer. I designed and coordinated the Company's first load research program. I also performed load studies used in cost-of-service studies and assisted in rate design activities.

In 1978, I accepted the position of Research Analyst in the Marketing and Rates department of Puget Sound Power and Light Company. In that position, I prepared the two-year sales and revenue forecasts used in the Company's budgeting activities and developed methods to perform both near- and long-term load forecasting studies.

In 1979, I accepted the position of Consultant in the Utility Rate Department of Ebasco Service Inc. In 1980, I was promoted to Senior Consultant in the Energy Management Services Department. At Ebasco I performed and assisted in numerous studies in the areas of cost of service, load research, and utility planning. In particular, I was involved in studies concerning analysis of excess capacity, evaluation of the planning activities of a major utility on behalf of its public service commission, development of a methodology for computing avoided costs and cogeneration rates, long-term electricity price forecasts, and cost allocation studies.

At Ebasco, I specialized in the development of computer models used to simulate utility production costs, system reliability, and load patterns. I was the principal author of production costing software used by eighteen utility clients and public service commissions for evaluation of marginal costs, avoided costs and production costing analysis. I assisted over a dozen utilities in the performance of marginal and avoided cost studies related to the PURPA of 1978. In this capacity, I worked with utility planners and rate specialists in quantifying the rate and cost impact of generation expansion alternatives. This activity included estimating carrying costs, O&M expenses, and capital cost estimates for future generation.

In 1982 I accepted the position of Senior Consultant with Energy Management Associates, Inc. and was promoted to Lead Consultant in June 1983. At EMA I trained and consulted with planners and financial analysts at several utilities in applications of the PROMOD and PROSCREEN planning models. I assisted planners in applications of these models to the preparation of studies evaluating the revenue requirements and financial impact of generation expansion alternatives, alternate load growth patterns and alternate regulatory treatments of new baseload generation. I also assisted in EMA's educational seminars where utility personnel were trained in aspects of production cost modeling and other modern techniques of generation planning.

I became a Principal in Kennedy and Associates in 1984. Since then I have performed numerous economic studies and analyses of the expansion plans of several utilities. I have testified on several occasions regarding plant cancellation, power system reliability, phase-in of new generating plants, and the proper rate treatment of new generating capacity. In addition, I have been involved in many projects over the past several years concerning the modeling of market prices in various regional power markets.

In January 2000, I founded RFI Consulting, Inc. whose practice is comparable to that of my former firm, J. Kennedy and Associates, Inc.

The testimony that I present is based on widely accepted industry standard techniques and methodologies, and unless otherwise noted relies upon information obtained in discovery or other publicly available information sources of the type frequently cited and relied upon by electric utility industry experts. All of the analyses that I perform are consistent with my education, training and experience in the utility industry. Should the source of any information presented in my testimony be unclear to the reader, it will be provided it upon request by calling me at 770-379-0505.

PAPERS AND PRESENTATIONS

Mid-America Regulatory Commissioners Conference - June 1984: "Nuclear Plant Rate Shock **-** Is Phase-In the Answer"

Electric Consumers Resource Council - Annual Seminar, September 1986: "Rate Shock, Excess Capacity and Phase-in"

The Metallurgical Society - Annual Convention, February 1987: "The Impact of Electric Pricing Trends on the Aluminum Industry"

Public Utilities Fortnightly - "Future Electricity Supply Adequacy: The Sky Is Not Falling" What Others Think, January 5, 1989 Issue

Public Utilities Fortnightly - "PoolCo and Market Dominance", December 1995 Issue

APPEARANCES

3/84	8924	KY	Airco Carbide	Louisville Gas & Electric	CWIP in rate base.
5/84	830470- EI	FL	Florida Industrial Power Users Group	Fla. Power Corp.	Phase-in of coal unit, fuel savings basis, cost allocation.
10/84	89-07-R	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power	Excess capacity.
11/84	R-842651	PA	Lehigh Valley	Pennsylvania Power Committee	Phase-in of nuclear unit. Power & Light Co.
2/85 cancellation of	I-840381	PA	Phila. Area Ind. Energy Users' Group	 Electric Co.	Philadelphia Economics of nuclear generating units.
3/85	Case No.	KY	Kentucky Industrial	Louisville Gas	Economics of cancelling fossil

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
	9243		Utility Consumers	& Electric Co.	generating units.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped storage generating units, optimal res. margin, excess capacity.
3/85	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear unit cancellation, load and energy forecasting, generation economics.
5/85	84-768-E-42T	WV	West Virginia Multiple Intervenors	Monongahela Power Co.	Economics - pumped storage generating units, reserve margin, excess capacity.
7/85	E-7, SUB 391	NC	Carolina Industrial Group for Fair Utility Rates	Duke Power Co.	Nuclear economics, fuel cost projections.
7/85	9299	KY	Kentucky Industrial Utility Consumers	Union Light, Heat & Power Co.	Interruptible rate design.
8/85	84-249-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Prudence review.
1/86	85-09-12	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power Co.	Excess capacity, financial impact of phase-in nuclear plant.
1/86	R-850152	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Phase-in and economics of nuclear plant.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power	Optimal reserve margins, prudence, off-system sales guarantee plan.
5/86	86-081-E-GI	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Generation planning study , economics prudence of a pumped storage hydroelectric unit.
5/86	3554-U	GA	Attorney General & Georgia Public Service Commission Staff	Georgia Power Co.	Cancellation of nuclear plant.
9/86	29327/28	NY	Occidental Chemical Corp.	Niagara Mohawk Power Co.	Avoided cost, production cost models.
9/86	E7-Sub 408	NC	NC Industrial Energy Committee	Duke Power Co.	Incentive fuel adjustment clause.
12/86	9437/613	KY	Attorney General of Kentucky	Big Rivers Elect. Corp.	Power system reliability analysis, rate treatment of excess capacity.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power	Economics and rate treatment of Bath County pumped storage County Pumped Storage Plant.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
6/87	PUC-87-013-RD E002/E-015 -PA-86-722	MN	Eveleth Mines & USX Corp.	Minnesota Power/ Northern States	Sale of generating unit and reliability Power requirements.

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of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
7/87	Docket 9885	KY	Attorney General of Kentucky	Big Rivers Elec. Corp.	Financial workout plan for Big Rivers.
8/87	3673-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear plant prudence audit, Vogtle buyback expenses.
10/87	R-850220	PA	WPP Industrial Intervenors	West Penn Power	Need for power and economics, County Pumped Storage Plant
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Cost allocation methods and interruptible rate design.
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Nuclear plant performance.
1/88	Case No. 9934	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Review of the current status of Trimble County Unit 1.
3/88	870189-EI	FL	Occidental Chemical Corp.	Fla. Power Corp.	Methodology for evaluating interruptible load.
5/88	Case No. 10217	KY	National Southwire Aluminum Co., ALCAN Alum Co.	Big Rivers Elec. Corp.	Debt restructuring agreement.
7/88	Case No. 325224	LA Div. I 19th Judicial District	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization gas sales and revenues.
10/88	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of gas sales and revenues.
12/88	88-171-EL-AIR 88-170-EL-AIR	OH OH	Ohio Industrial Energy Consumers	Toledo Edison Co., Cleveland Electric Illuminating Co.	Power system reliability reserve margin.
1/89	I-880052	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Nuclear plant outage, replacement fuel cost recovery.
2/89	10300	KY	Green River Steel K	Kentucky Util.	Contract termination clause and interruptible rates.
3/89	P-870216 283/284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power	Reserve margin, avoided costs.
5/89	3741-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Prudence of fuel procurement.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Need and economics coal & nuclear capacity, power system planning.
10/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Power system planning, economic and reliability analysis, nuclear planning, prudence.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/89	89-128-U	AR	Arkansas Electric Energy Consumers	Arkansas Power Light Co.	Economic impact of asset transfer and stipulation and settlement agreement.
11/89	R-891364	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Sale/leaseback nuclear plant, excess capacity, phase-in delay imprudence.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Sale/leaseback nuclear power plant.
4/90	89-1001-EL-AIR	OH	Industrial Energy Consumers	Ohio Edison Co.	Power supply reliability, excess capacity adjustment.
4/90	N/A	N.O.	New Orleans Business Counsel	New Orleans Public Service Co.	Municipalization of investor-owned utility, generation planning & reliability
7/90	3723-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization adjustment rider.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirements gas & electric, CWIP in rate base.
9/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Power system planning study.
12/90	U-9346	MI	Association of Businesses Advocating Tariff Equity (ABATE)	Consumers Power	DSM Policy Issues.
5/91	3979-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	DSM, load forecasting and IRP.
7/91	9945	TX	Office of Public Utility Counsel	El Paso Electric Co.	Power system planning, quantification of damages of imprudence, environmental cost of electricity
8/91	4007-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Integrated resource planning, regulatory risk assessment.
11/91	10200	TX	Office of Public	Texas-New Mexico Utility Counsel	Imprudence disallowance. Power Co.
12/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Year-end sales and customer adjustment, jurisdictional allocation.
1/92	89-783-E-C	WVA	West Virginia Energy Users Group	Monongahela Power Co.	Avoided cost, reserve margin, power plant economics.
3/92	91-370	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Interruptible rates, design, cost allocation.
5/92	91890	FL	Occidental Chemical Corp.	Fla. Power Corp.	Incentive regulation, jurisdictional separation, interruptible rate design.
6/92	4131-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Integrated resource planning, DSM.
9/92	920324	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Cost allocation, interruptible rates decoupling and DSM.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/92	4132-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Residential conservation program certification.
10/92	11000	TX	Office of Public Utility Counsel	Houston Lighting and Power Co.	Certification of utility cogeneration project.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Direct)	Production cost savings from merger.
11/92	8469	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, revenue distribution.
11/92	920606	FL	Florida Industrial Power Users Group	Statewide Rulemaking	Decoupling, demand-side management, conservation, Performance incentives.
12/92	R-009 22378	PA	Armco Advanced Materials	West Penn Power	Energy allocation of production costs.
1/93	8179	MD	Eastalco Aluminum/ Westvaco Corp.	Potomac Edison Co.	Economics of QF vs. combined cycle power plant.
2/93	92-E-0814 88-E-081	NY	Occidental Chemical Corp.	Niagara Mohawk Power Corp.	Special rates, wheeling.
3/93	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Surrebuttal)	Production cost savings from merger.
4/93	EC92 21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	GSU Merger prodcution cost savings
6/93	930055-EU	FL	Florida Industrial Power Users' Group	Statewide Rulemaking	Stockholder incentives for off-system sales.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers & Attorney General	Big Rivers Elec. Corp.	Prudence of fuel procurement decisions.
9/93	4152-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Cost allocation of pollution control equipment.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minn. Power Co.	Analysis of revenue req. and cost allocation issues.
4/94	93-465	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Review and critique proposed environmental surcharge.
4/94	4895-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co	Purchased power agreement and fuel adjustment clause.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Light Co.	Rev. requirements, incentive compensation.
7/94	94-0035- E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue annualization, ROE performance bonus, and cost allocation.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Revenue requirements, ROE performance bonus, and revenue distribution.
1/95	94-332	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Environmental surcharge.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
1/95	94-996-EL-AIR	OH	Industrial Energy Users of Ohio	Ohio Power Company	Cost-of-service, rate design, demand allocation of power
3/95	E999-CI	MN	Large Power Intervenor	Minnesota Public Utilities Comm.	Environmental Costs Of electricity
4/95	95-060	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Company	Six month review of CAAA surcharge.
11/95	I-940032	PA	The Industrial Energy Consumers of Pennsylvania	Statewide - all utilities	Direct Access vs. Poolco, market power.
11/95	95-455	KY	Kentucky Industrial	Kentucky Utilities	Clean Air Act Surcharge,
12/95	95-455	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Clean Air Act Compliance Surcharge.
6/96	960409-EI	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Polk County Power Plant Rate Treatment Issues.
3/97	R-973877	PA	PAIEUG.	PECO Energy	Stranded Costs & Market Prices.
3/97	970096-EQ	FL	FIPUG	Fla. Power Corp.	Buyout of QF Contract
6/97	R-973593	PA	PAIEUG	PECO Energy	Market Prices, Stranded Cost
7/97	R-973594	PA	PPLICA	PP&L	Market Prices, Stranded Cost
8/97	96-360-U	AR	AEEC	Entergy Ark. Inc.	Market Prices and Stranded Costs, Cost Allocation, Rate Design
10/97	6739-U	GA	GPSC Staff	Georgia Power	Planning Prudence of Pumped Storage Power Plant
10/97	R-974008 R-974009	PA	MIEUG PICA	Metropolitan Ed. PENELEC	Market Prices, Stranded Costs
11/97	R-973981	PA	WPII	West Penn Power	Market Prices, Stranded Costs
11/97	R-974104	PA	DII	Duquesne Light Co.	Market Prices, Stranded Costs
2/98	APSC 97451 97452 97454	AR	AEEC	Generic Docket	Regulated vs. Market Rates, Rate Unbundling, Timetable for Competition
7/98	APSC 87-166	AR	AEEC	Entergy Ark. Inc.	Nuclear decommissioning cost estimates & rate treatment.
9/98	97-035-01	UT	DPS and CCS	PacifiCorp	Net Power Cost Stipulation, Production Cost Model Audit
12/98	19270	TX	OPC	HL&P	Reliability, Load Forecasting
4/99	19512	TX	OPC	SPS	Fuel Reconciliation
4/99	99-02-05	CT	CIEC	CL&P	Stranded Costs, Market Prices
4/99	99-03-04	CT	CIEC	UI	Stranded Costs, Market Prices
6/99	20290	TX	OPC	CP&L	Fuel Reconciliation

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
7/99	99-03-36	CT	CIEC	CL&P	Interim Nuclear Recovery
7/99	98-0453	WV	WVEUG	AEP & APS	Stranded Costs, Market Prices
12/99	21111	TX	OPC	EGSI	Fuel Reconciliation
2/00	99-035-01	UT	CCS	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
5/00	99-1658	OH	AK Steel	CG&E	Stranded Costs, Market Prices
6/00	UE-111	OR	ICNU	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
9/00	22355	TX	OPC	Reliant Energy	Stranded cost
10/00	22350	TX	OPC	TXU Electric	Stranded cost
10/00	99-263-U	AR	Tyson Foods	SW Elec. Coop	Cost of Service
12/00	99-250-U	AR	Tyson Foods	Ozarks Elec. Coop	Cost of Service
01/01	00-099-U	AR	Tyson Foods	SWEPCO	Rate Unbundling
02/01	99-255-U	AR	Tyson Foods	Ark. Valley Coop	Rate Unbundling
03/01	UE-116	OR	ICNU	PacifiCorp	Net Power Costs
6/01	01-035-01	UT	DPS and CCS	PacifiCorp	Net Power Costs
7/01	A.01-03-026	CA	Roseburg FP	PacifiCorp	Net Power Costs
7/01	23550	TX	OPC	EGSI	Fuel Reconciliation
7/01	23950	TX	OPC	Reliant Energy	Price to beat fuel factor
8/01	24195	TX	OPC	CP&L	Price to beat fuel factor
8/01	24335	TX	OPC	WTU	Price to beat fuel factor
9/01	24449	TX	OPC	SWEPCO	Price to beat fuel factor
10/01	20000-EP 01-167	WY	WIEC	PacifiCorp	Power Cost Adjustment Excess Power Costs
2/02	UM-995	OR	ICNU	PacifiCorp	Cost of Hydro Deficit
2/02	00-01-37	UT Plant	CCS	PacifiCorp	Certification of Peaking
4/02	00-035-23	UT	CCS	PacifiCorp	Cost of Plant Outage, Excess Power Cost Stipulation.
4/02	01-084/296	AR	AEEC	Entergy Arkansas	Recovery of Ice Storm Costs
5/02	25802	TX	OPC	TXU Energy	Escalation of Fuel Factor
5/02	25840	TX	OPC	Reliant Energy	Escalation of Fuel Factor
5/02	25873	TX	OPC	Mutual Energy CPL	Escalation of Fuel Factor
5/02	25874	TX	OPC	Mutual Energy WTU	Escalation of Fuel Factor
5/02	25885	TX	OPC	First Choice	Escalation of Fuel Factor
7/02	UE-139	OR	ICNU	Portland General	Power Cost Modeling
8/02	UE-137	OP	ICNU	Portland General	Power Cost Adjustment Clause

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/02	RPU-02-03	IA	Maytag, et al	Interstate P&L	Hourly Cost of Service Model
11/02	20000-Er 02-184	WY	WIEC	PacifiCorp	Net Power Costs, Deferred Excess Power Cost
12/02	26933	TX	OPC	Reliant Energy	Escalation of Fuel Factor
12/02	26195	TX	OPC	Centerpoint Energy	Fuel Reconciliation
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	UE-134	OR	ICNU	PacifiCorp	West Valley CT Lease payment
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	26186	TX	OPC	SPS	Fuel Reconciliation
2/03	UE-02417	WA	ICNU	PacifiCorp	Rate Plan Stipulation, Deferred Power Costs
2/03	27320	TX	OPC	Reliant Energy	Escalation of Fuel Factor
2/03	27281	TX	OPC	TXU Energy	Escalation of Fuel Factor
2/03	27376	TX	OPC	CPL Retail Energy	Escalation of Fuel Factor
2/03	27377	TX	OPC	WTU Retail Energy	Escalation of Fuel Factor
3/03	27390	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27511	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27035	TX	OPC	AEP Texas Central	Fuel Reconciliation
05/03	03-028-U	AR	AEEC	Entergy Ark., Inc.	Power Sales Transaction
7/03	UE-149	OR	ICNU	Portland General	Power Cost Modeling
8/03	28191	TX	OPC	TXU Energy	Escalation of Fuel Factor
11/03	20000-ER -03-198	WY	WIEC	PacifiCorp	Net Power Costs
2/04	03-035-29	UT	CCS	PacifiCorp	Certification of CCCT Power Plant, RFP and Bid Evaluation
6/04	29526	TX	OPC	Centerpoint	Stranded cost true-up.
6/04	UE-161	OR	ICNU	Portland General	Power Cost Modeling
7/04	UM-1050	OR	ICNU	PacifiCorp	Jurisdictional Allocation
10/04	15392-U 15392-U	GA	Calpine	Georgia Power/ SEPCO	Fair Market Value of Combined Cycle Power Plant
12/04	04-035-42	UT	CCS		PacifiCorp Net power costs
02/05	UE-165	OP	ICNU	Portland General	Hydro Adjustment Clause
05/05	UE-170	OR	ICNU	PacifiCorp	Power Cost Modeling
7/05	UE-172	OR	ICNU	Portland General	Power Cost Modeling
08/05	UE-173	OR	ICNU	PacifiCorp	Power Cost Adjustment
8/05	UE-050482	WA	ICNU	Avista	Power Cost modeling, Energy Recovery Mechanism
8/05	31056	TX	OPC	AEP Texas Central	Stranded cost true-up.
11/05	UE-05684	WA	ICNU	PacifiCorp	Power Cost modeling, Jurisdictional Allocation, PCA

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
2/06	05-116-U	AR	AEEC	Entergy Arkansas	Fuel Cost Recovery
4/06	UE-060181	WA	ICNU	Avista	Energy Cost Recovery Mechanism
5/06	22403-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
6/06	UM 1234	OR	ICNU	Portland General	Deferral of outage costs
6/06	UE 179	OR	ICNU	PacifiCorp	Power Costs, PCAM
7/06	UE 180	OR	ICNU	Portland General	Power Cost Modeling, PCAM
12/06	32766	TX	OPC	SPS	Fuel Reconciliation
1/07	23540-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
2/07	06-101-U	AR	AEEC	Entergy Arkansas	Cost Allocation and Recovery
2/07	UE-061546	WA	ICNU/Public Counsel	PacifiCorp	Power Cost Modeling, Jurisdictional Allocation, PCA
2/07	32710	TX	OPC	EGSI	Fuel Reconciliation
6/07	UE 188	OR	ICNU	Portland General	Wind Generator Rate Surcharge
6/07	UE 191	OR	ICNU	PacifiCorp	Power Cost Modeling
6/07	UE 192	OR	ICNU	Portland General	Power Cost Modeling
9/07	UM 1330	OR	ICNU	PGE, PacifiCorp	Renewable Resource Tariff
10/07	06-152-U	AR	AEEC	EAI	CA Rider, Plant Acquisition
10/07	07-129-U	AR	AEEC	EAI	Annual Earnings Review Tariff
10/07	06-152-U	AR	AEEC	EAI	Purchase of combined cycle power plant.
04/08	26794	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Case

Oregon TAM Update
November 7, 2007

All numbers are on a total company basis

CY2008 NPC, July 2007 Filing $979,465,225

CY2008 NPC, Final Updates

Update		
0	July Filing Prior to Adopted Adjustments 1, 4 and 5	12,761,801
1	Commission Ordered EFOR	(390,241)
2	City of Hurricane Sale and Purchase	(254,499)
3	UAMPS Sale	129,252
4	Updated PSCo Sales Prices	646,276
5	Updated ExxonMobil QF	269,878
6	Updated Mountain Wind QF	108,909
7	Updated Schwendimen QF	(335,763)
8	Kennecott QF	(520,023)
9	Exclude Goodnoe	16,614,707
10	Exclude Pioneer Ridge QF	(2,458,275)
11	Clay Basin Gas Storage	(1,250,350)
12	Lake Side Pipeline Charges	299,513
13	Short Term Firm Transactions	(5,938,085)
14	Official Forward Price Curve	(5,435,880)
15	Gas Swaps	(4,615,798)
16	Re-shaped Hydro, plus Douglas Wells Lands Right	142,943
17	Fuel Costs	2,730,310
18	System balancing impact of all adjustments =	1,770,639
19	Short Term Trading Margin	(3,079,647)
	Total Adjustments from July Filing =	**$11,195,668**
	CY2008 NPC, prior to adopted adjustments 1, 4 and 5	**$990,660,893**
Adopted		
1	Uneconomic CT Operation	(1,147,205)
4	Call Options	(5,128,355)
5	Carbon at 80% C.F.	(3,684,949)
	Total Adjustments from updated =	**($9,960,509)**
	CY2008 Final NPC =	**$980,700,383**

CONFIDENTIAL:
Exhibit ICNU/103
Analysis of Currant Creek Uneconomic Generation

[redacted]

CONFIDENTIAL:
Exhibit ICNU/103
Analysis of Currant Creek Uneconomic Generation

[redacted]

CONFIDENTIAL:
Exhibit ICNU/103

[redacted]ek Uneconomic Generation

[redacted]

Confidential Exhibit 104
Development of Night Time Shutdown Screen - Currant Creek
Monthly Total Hourly Cost Difference with and without Currant Creek

[redacted]

Source: Docket: 07-035-93 / Utah GRC 2007
CCS Data Request 2.63

Exhibit ICNU/105
PacifiCorp Hermiston Loss Workpaper
and ICNU Corrections

Actual Hermiston Generation

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2002	1,477,254	149,818	160,269	151,440	125,894	58,949	3,314	34,048	157,998	159,741	168,522	161,471	145,790
2003	1,762,710	170,356	154,901	133,127	132,418	109,181	156,155	162,431	96,092	160,575	168,326	164,243	154,905
2004	1,867,144	158,529	147,496	148,506	162,825	130,541	132,013	163,180	160,466	160,815	168,126	166,643	168,004
2005	1,857,143	169,767	155,725	146,045	160,962	74,130	157,826	162,494	165,894	157,300	169,505	166,837	170,658
2006	1,553,240	165,300	134,977	167,592	37,961	15,965	53,373	162,127	159,268	163,666	161,510	162,775	168,726
2007	848,689	162,855	156,345	132,082	141,818	103,736	151,853	-	-	-	-	-	-
Average	1,531,554	164,113	148,636	148,556	125,892	81,093	123,766	162,558	145,430	160,589	166,867	165,125	165,573

48 Month BPA Hermiston Losses (1)

	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	70,679	6,597	5,975	5,972	5,061	3,260	4,975	6,535	5,846	6,456	6,708	6,638	6,656

BPA Hermiston Losses 2.01% (Based on on estimated losses annual losses as shown below)

Note: Hermiston Losses are doubled to account for the Hermiston Purchase

PacifiCorp
Input range to Demand File

1	**Jan**	6597
2	**Feb**	5975
3	**Mar**	5972
4	**Apr**	5061
5	**May**	3260
6	**Jun**	4975
7	**Jul**	6535
8	**Aug**	5846
9	**Sep**	6456
10	**Oct**	6708
11	**Nov**	6638
12	**Dec**	6656
		70679

ICNU
Input range to Demand File

1	Jan	4825
2	Feb	4370
3	Mar	4368
4	Apr	3701
5	May	2384
6	Jun	3639
7	Jul	4779
8	Aug	4276
9	Sep	4721
10	Oct	4906
11	Nov	4855
12	Dec	4868
		51692

PacifiCorp Assumptions
BPA Hermiston Losses - calc
Oct. 1999 through Jan 2005 **75,000** = E[Annual Losses]
Hermiston Gen (MWh)
Per EX 10 Attachements

Corrected Assumptions

April 99-Dec 31 04		324,570
1,999	April	6,232
	May	5,680
	Jun	5,559
	July	6,171
	August	6,543
	Septemberg	5,824
Oct 1 99 - Dec 31 04		288,561
Start	10/1/1999	
End	12/31/2004	
Days	1,918	
Years	5.25	
Annual Avearge		54,914

PACIFICORP

PACIFIC POWER UTAH POWER

INTERNAL CORRESPONDENCE

DATE: March 3, 2005

TO: Records Management
1050 LCT

FROM: Kristie Sharp
600 LCT

SUBJECT: BPA Correspondence received re: Contract No. DE-MS79-94BP94316 (Hermiston)

Enclosed for vault files please find correspondence from Mark Miller and Dennis Oster of Bonneville Power Administration regarding return of transmission losses under Contract No. DE-MS79-94BP94316 (Hermiston).

cc: C&T Contract Notice Distribution

File: BPA - Correspondence

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

POWER BUSINESS LINE

February 22, 2005

In reply refer to: PT-5

Mr. Colin Persichetti, Director, Contract Administration
PacifiCorp
825 NE Multnomah
Portland, OR 97232

Dear Mr. Persichetti:

On January 13, 2005, the Bonneville Power Administration's (BPA) Transmission Business Line (TBL) discovered that since April 16, 1999, PacifiCorp had not been returning losses under PacifiCorp's FPT Transmission Agreement serving the Hermiston Generation Project, BPA Contract No. DE-MS79-94BP94316 (Hermiston). Therefore, BPA's Power Business Line (PBL) supplied the energy for the losses. The accumulated amount of energy provided by the PBL and used by PacifiCorp is 324,570 MW hours. Although discussions have been initiated between BPA and PacifiCorp on this topic, this letter is to officially notify PacifiCorp of the problem, and to request appropriate compensation for the value of the energy provided by BPA. The basis for the request is described below, and is supported by Attachment A, which provides the calculation for the value of the losses not returned.

I. Background

PacifiCorp's transmission contract requires that losses be returned 168 hours after the scheduled energy deliveries, in amounts calculated from the energy schedules. However, from April 16, 1999, through January 18, 2005, PacifiCorp did not return losses for Hermiston. As a result, the BPA PBL provided the power for the losses without receiving any energy or monetary payment.

II. Compensation for Losses

BPA has used the monthly average Mid-Columbia index prices for the months in which the energy was supplied by the PBL. This method of valuing these losses is the most appropriate because it accurately reflects the cost to the PBL. This cost is $21,023,279.

III. Resolution

Representatives of the TBL and PBL would be happy to meet with you to answer any questions you may have. If PacifiCorp does not respond by March 4, 2005, the TBL will include the $21,023,279 amount on PacifiCorp's next Transmission bill. As an alternative to a financial payment, the PBL is willing to discuss payment in the form of energy deliveries valued at the above amount.

Sincerely,

Mark Miller, Account Executive
Power Business Line

Dennis Oster, Account Executive
Transmission Business Line

ENC: Attachment A

Attachment A

1/19/2005

Hermiston PacifiCorp FPT Loss MWhr Totals

		DJ Mid-C Flat	
1999 April	6,231.751	20.44	127,378
1999 May	5,680.225	22.43	127,389
1999 June	5,558.850	16.94	94,146
1999 July	6,170.957	20.13	124,210
1999 August	6,542.692	24.37	159,467
1999 September	5,283.946	29.40	155,371
1999 October	5,074.676	42.24	214,369
1999 November	5,516.388	28.79	158,816
1999 December	7,125.861	23.73	169,092
1999 Total	53,185.346		**1,330,238**
2000 January	8,194.295	25.59	209,725
2000 February	6,399.495	26.17	167,477
2000 March	5,127.225	27.27	139,800
2000 April	7,031.437	22.83	160,546
2000 May	5,991.076	49.27	295,193
2000 June	5,378.522	127.70	686,854
2000 July	5,484.858	98.08	537,936
2000 August	4,945.984	166.06	821,348
2000 September	4,319.436	114.73	495,553
2000 October	4,184.820	96.71	404,720
2000 November	4,686.104	161.29	755,810
2000 December	5,760.417	524.64	3,022,167
2000 Total	67,503.669		**7,697,129**
2001 January	5,032.416	261.17	1,314,339
2001 February	4,470.726	275.21	1,230,408
2001 March	3,732.881	260.71	973,212
2001 April	3,873.632	289.74	1,122,336
2001 May	3,685.531	223.45	823,530
2001 June	4,368.918	62.00	270,874
2001 July	3,292.735	53.04	174,641
2001 August	3,698.438	39.71	146,859
2001 September	3,133.472	22.72	71,204
2001 October	3,911.309	24.49	95,774
2001 November	4,315.885	22.36	96,484
2001 December	4,774.930	24.24	115,740
2001 Total	48,290.873		**6,435,402**
2002 January	4,928.319	18.79	92,627
2002 February	5,245.813	20.30	106,498

2002 March	4,025.549	34.32	138,151
2002 April	4,443.344	19.44	86,369
2002 May	2,167.263	19.02	41,217
2002 June	189.290	7.51	1,422
2002 July	1,348.113	9.91	13,361
2002 August	5,153.384	17.90	92,269
2002 September	3,872.951	24.59	95,254
2002 October	4,059.979	28.52	115,791
2002 November	4,625.936	30.99	143,350
2002 December	4,225.930	37.29	157,578
2002 Total	44,285.871		**1,083,888**
2003 January	4,614.798	36.55	168,672
2003 February	4,336.866	49.99	216,787
2003 March	4,359.434	45.81	199,698
2003 April	4,881.816	31.75	154,980
2003 May	4,466.269	28.84	128,808
2003 June	6,676.924	31.89	212,916
2003 July	5,112.012	44.50	227,505
2003 August	2,719.735	39.79	108,210
2003 September	3,504.078	38.95	136,482
2003 October	3,898.997	34.82	135,769
2003 November	4,480.907	35.30	158,175
2003 December	5,183.123	39.19	203,123
2003 Total	54,234.959		**2,051,124**
2004 January	4,960.862	44.58	221,159
2004 February	4,273.041	40.90	174,756
2004 March	4,225.078	36.94	156,054
2004 April	4,673.723	40.16	187,707
2004 May	4,711.587	43.97	207,166
2004 June	5,373.705	31.64	170,033
2004 July	5,037.475	47.76	240,576
2004 August	4,503.483	47.65	214,589
2004 September	4,168.204	37.25	155,261
2004 October	4,202.497	43.02	180,773
2004 November	4,907.984	46.31	227,274
2004 December	6,031.668	48.10	290,150
2004 Total	57,069.307		**2,425,498**

Grand Total 1999 Through 2004	324,570.025
	$21,023,279

*Numerical Example of Ramping Losses on Gadsby 3 unit for March

Unit ID	Startup time from Off-line Period	Hour Ending (MT)	Declared Available MW	Actual Hourly Generation	Hour Number from startup	Actual Difference between Avail & Hrly Generation	Cumulative Total of Differences	Comments		Reserve Allocation
GAD-3	03/28/2007 12:14	03/28/2007 13:00	100	4	1			Hour 1 never qualifes because it is usually a patial hour and can never be at full load	(Hour Start PST)	
		03/28/2007 14:00	100	30	2	70	70	Calculates as long as there is a 10% difference between Avail & Generated MW	28-Mar-07 12:00:00	11
		03/28/2007 15:00	100	62	3	38	108	Calculates as long as there is a 10% difference between Avail & Generated MW	28-Mar-07 13:00:00	30
		03/28/2007 16:00	100	64	4	36	144	Calculates as long as there is a 10% difference between Avail & Generated MW	28-Mar-07 14:00:00	30
		03/28/2007 17:00	100	64	5	36	180	Calculates as long as there is a 10% difference between Avail & Generated MW	28-Mar-07 15:00:00	30
		03/28/2007 18:00	100	64	6	36	216	Calculates as long as there is a 10% difference between Avail & Generated MW	28-Mar-07 16:00:00	30
		03/28/2007 19:00	100	63	7	37	253	Calculates as long as there is a 10% difference between Avail & Generated MW	28-Mar-07 17:00:00	30
		03/28/2007 20:00	100	48	8	52	305	Calculates as long as there is a 10% difference between Avail & Generated MW	28-Mar-07 18:00:00	30
		03/28/2007 21:00	100	45	9	55	360	Calculates as long as there is a 10% difference between Avail & Generated MW	28-Mar-07 19:00:00	30
		03/28/2007 22:00	100	39	10	61	421	Calculates as long as there is a 10% difference between Avail & Generated MW	28-Mar-07 20:00:00	30
		03/28/2007 23:00	100	5	11	95	**516**	Partial Hour on-line, heading into Reserve Shutdown status	28-Mar-07 21:00:00	10
GAD-3	03/29/2007 13:12	03/29/2007 14:00	100	6	1			Hour 1 never qualifes because it is usually a patial hour and can never be at full load	3/29/07 12:00 PM	4
		03/29/2007 15:00	100	48	2	52	52	Calculates as long as there is a 10% difference between Avail & Generated MW	3/29/07 1:00 PM	11
		03/29/2007 16:00	100	58	3	42	94	Calculates as long as there is a 10% difference between Avail & Generated MW	3/29/07 2:00 PM	21
		03/29/2007 17:00	100	59	4	41	135	Calculates as long as there is a 10% difference between Avail & Generated MW	3/29/07 3:00 PM	30
		03/29/2007 18:00	100	59	5	41	176	Calculates as long as there is a 10% difference between Avail & Generated MW	3/29/07 4:00 PM	30
		03/29/2007 19:00	100	58	6	42	218	Calculates as long as there is a 10% difference between Avail & Generated MW	3/29/07 5:00 PM	30
		03/29/2007 20:00	100	42	7	58	276	Calculates as long as there is a 10% difference between Avail & Generated MW	3/29/07 6:00 PM	30
		03/29/2007 21:00	100	47	8	53	329	Calculates as long as there is a 10% difference between Avail & Generated MW	3/29/07 7:00 PM	30
		03/29/2007 22:00	100	46	9	54	383	Calculates as long as there is a 10% difference between Avail & Generated MW	3/29/07 8:00 PM	30
		03/29/2007 23:00	100	5	10	95	**478**	Partial Hour on-line, heading into Reserve Shutdown status	3/29/07 9:00 PM	11
					Total MWH Lost =		**994**			
										487

*The 48 months under consideration ended in June 2007. Therefore, the March periods contained within that 48 months were in years 2004, 2005, 2006 & 2007.
All of the years prior to 2007 had Gadsby 3 unit on Reserve Shutdown during those complete months and therefore were not subjected to ramping losses.

April 30, 2008

TO: Brad Van Cleve
Industrial Customers of NW Utilities

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to ICNU Data Request 3.207
Dated April 16, 2008
Question No. 207

Request:

It appears that the Company applies the same deration factor to unit minimum capacities as it does to the maximum capacities (generally 1-EFOR in months w/o planned outages) in Monet. Please confirm whether this is correct, please explain the purpose of this adjustment, and please explain why it is proper.

Response:

This is correct. Monet is in effect modeling a 100 MW plant with a 50 MW minimum level of operation as if plant operation at 50 MW is not available 5% of the time.

April 30, 2008

TO: Brad Van Cleve
Industrial Customers of NW Utilities

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to ICNU Data Request 3.208
Dated April 16, 2008
Question No. 208

Request:

It appears that the Company uses the same heat rates at maximum capacity irrespective of the level of capacity deration applied for outages in Monet. For example, if Monet included a 100 mW unit with a 5% EFOR, it would be modeled as a 95 mW unit in Monet. The heat rate for the unit when derated to 95 mW would be equal to that of the unit at full load (100 mW) without any deration. Please confirm if this is correct, and please explain why.

Response:

This is correct. Monet is in effect modeling a 100 MW plant operating at a heat rate appropriate to 100 MW operation with the plant (operating at 100 MW) not available 5% of the time.

April 30, 2008

TO: Brad Van Cleve
Industrial Customers of NW Utilities

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to ICNU Data Request 3.209
Dated April 16, 2008
Question No. 209

Request:

It appears that the Company uses the same heat rates at minimum capacity irrespective of the level of capacity deration applied for outages in monet. For example, if Monet included a 100 mW unit with a 5% EFOR and a 50 mW minimum, it would be modeled in the program as a unit with a minimum of 47.5 mW. However, the heat rate for the unit when derated to 47.5 mW would be equal to that of the unit at minimum load (50 mW) without deration. Please confirm if this is correct, and please explain why.

Response:

This is correct. Monet is in effect modeling a 100 MW plant operating at a heat rate appropriate to 50 MW operation with the plant (operating at 50 MW) not available 5% of the time.

EX ICNU/111

Example Illustrating Need to Derate Minimum Capacity and Adjust Heat Rates

Scenario 1 - No Minimum Loading Constraint

Probabilistic Example

Case	Comb. Prob.	Prob Hunter	Prob Gadsby	State Hunter	mW Hunter	Avg Cost Hunter	Total Cost Hunter	State Gadsby	mW Gadsby	Inc. Cost Gadsby	Avg Cost Gadsby	Total Cost Gadsby	Purchase or Sale mW	Cost/mWh	Total Cost Purchase	Load = Combined mW	Tot. Cost	$/mWh	Error
1	78.2609%	86.9565%	90.0000%	Up	460	11.85	5449	Up	70	67.99	75.88	5311	-30	67.99	(2,039.75)	500	8,721	17.44	
2	8.6957%	86.9565%	10.0000%	Up	460	11.85	5449	Down	0	0	0	0	40	67.99	2,719.66	500	8,169	16.34	
3	11.7391%	13.0435%	90.0000%	Down	0	0	0	Up	70	67.99	75.88	5311	430	67.99	29,236.37	500	34,548	69.10	
4	1.3043%	13.0435%	10.0000%	Down	0	0	0	Down	0	0	0	0	500	67.99	33,995.78	500	33,996	67.99	
Probablity Wtd.	100.0000%				400.0		4,738		63.0		75.88	4,780	37.0		2,516	500	12,034	24.07	0
Derate Method - Unadjusted Heat Rates				Up	400	11.87	4749	Up	70	67.99	75.88	5311	30	67.99	2,039.75	500	12,100	24.20	66
Derate Method - Correct Heat Rates				**UP**	**400**	**11.85**	**4738**	**Up**	**63**	**67.99**	**75.88**	**4780**	**37**	**67.99**	**2,515.69**	**500**	**12,034**	**24.07**	**0**

Scenario 1 - Minimum Loading Constraint is Binding

Probabilistic Example

Case	Comb. Prob.	Prob Hunter	Prob Gadsby	State Hunter	mW Hunter	Avg Cost Hunter	Total Cost Hunter	State Gadsby	mW Gadsby	Inc. Cost Gadsby	Avg Cost Gadsby	Total Cost Gadsby	Purchase or Sale mW	Cost/mWh	Total Cost Purchase	Load = Combined mW	Tot. Cost	$/mWh	Error
1	90.0000%	100.0000%	90.0000%	Up	360	11.91	4288	Up	40	67.44	82.00	3280	0	67.99	-	400	7,568	18.92	
2	10.0000%	100.0000%	10.0000%	Up	400	11.87	4749	Down	0	0	0	0	0	67.99	-	400	4,749	11.87	
3	0.0000%	0.0000%	90.0000%	Down	0	0	0	Up	40	67.44	82.00	3280	360	67.99	24,476.96	400	27,757	69.39	
4	0.0000%	0.0000%	10.0000%	Down	0	0	0	Down	0	0	0	0	400	67.99	27,196.62	400	27,197	67.99	
Probablity Wtd.	100.0000%				364.0	11.9	4,334.3		36.0		73.8	2,952.0	0.0	#DIV/0!	0.0	400.0	7,286.3	18.2	0
Derate Method - Unadjusted Heat Rates				Up	360	11.91	4288	Up	40	67.44	82.00	3280	0	67.99	-	400	7,568	18.92	282
Derate Method - Correct Heat Rates				UP	364.00	11.91	4334	Up	36.0	67.44	82.00	2952	0	67.99	-	400	7,286	18.22	(0)

WIEC Data Request 5.3

Reference WIEC 2.6h. Explain why retail customers should be charged costs for transmission imbalances caused by third party loads.

Response to WIEC Data Request 5.3

Transmission imbalances are the net difference between metered loads and scheduled resources by third party entities that have load within the Company's control area. For hours when a third party's metered loads exceed scheduled resources, the Company sells power to that third party at prices that is at or above the then current market price. For hours when a third party's scheduled resources exceed metered loads, the Company purchases power from that third party a price that is at or below the then current market price. For the 12-months ending November 30, 2007, the sum of the hourly transmission imbalance transactions resulted in a net purchase to meet load at prices favorable to buying from the market and therefore these costs should be included in the PCAM. If the costs were removed, the energy would have to be removed as well in order to provide a matching of the costs and energy associated with the transmission imbalance transactions leaving the PCAM with not enough resources to meet load.

Exhibit ICNU/113
Proposed Minimum Filing Requirements

1.1 Please identify the GRID the Four Year Period used to determine outage rates and other input items in GRID.

1.2 Please provide all documents, workpapers or other information relied upon by the Company in determining the market caps used in GRID for the Pro-Forma Period. Please provide this information electronically in excel spreadsheets with all formulas intact.

1.3 Please provide the current topology maps in GRID. Please explain all the differences that have been made to the topology since the last TAM case and explain why the changes were made. Provide supporting documentation, such as contracts resulting in changes to the transfer capabilities used in GRID.

1.4 Please list and explain all modeling or logic changes to the methodology used to compute data inputs or any other type of enhancement to the GRID model that have been implemented since the most recent Oregon TAM case. Please provide a statement of the direction of change in net power cost resulting from each such change and documentation describing each change.

1.5 Please provide all monthly compilations of actual net power costs produced by PacifiCorp for the past four years and year to date. To the extent readily available, please provide supporting transaction data in the format of PacifiCorp's response to ICNU data request 1.5 in UE 199.

1.6 Please provide workpapers showing the computation of the outage rates (planned and unplanned) used in GRID. Include all backup data showing each outage (planned or unplanned, etc.) and duration (planned or unplanned) considered in the four year period, including NERC cause code, type of event, duration, energy lost, etc. Please provide workpapers showing the derivation of any monthly outage rate assumptions used. Please provide this information electronically and in the case of excel spreadsheets with all formulas intact. Please provide in the same format as PacifiCorp's responses to ICNU data requests 1.6-1 and 1.6-2 from UE 199.

1.7 Please provide the date and a copy of the forward price curve, showing monthly heavy load hour and light load hour and hourly scalars, used in creating the Test Year GRID studies.

1.8 Please provide the loss factor data showing losses for the system and for each state for the most recent five calendar years and for the most recent five fiscal years. Compare those loss factors to those that were used in developing loads for the GRID study(ies) for the Pro-Forma period used in this case. Please provide workpapers and other supporting documentation underlying the figures electronically and in the case of excel spreadsheets with formulas intact.

1.9 Please provide the system level loss factors assumed in GRID in the most recent (or current) Utah, Oregon, Idaho, Wyoming and Washington rate cases.

1.10 Please provide workpapers showing all short-term firm transactions modeled in the test year GRID study. Please provide the information in the same format as that provided in PacifiCorp's responses to ICNU data requests 1.11 in UE 199. In addition include a designation for each contract as to its purpose (i.e., trading, arbitrage or balancing.)

1.11 For all contracts modeled in GRID that were not included in the most recent Oregon TAM case, please provide the following:

a. A copy of the contract (in pdf or electronic format, if available).

b. Any workpapers used to develop the GRID input assumptions related to the contract.

c. Any economic analysis, including options value studies or similar analyses, used to evaluate the contract prior to signing.

d. Please indicate whether cost/benefit analyses conducted on these contracts relied upon extrinsic value.

1.12 Please provide a compilation and supporting workpapers detailing arbitrage and trading profits from STF contracts (please use the format from PacifiCorp's response to ICNU data request 1.13 from UE 199):

a. Provide for the most recent four years of actual data.

b. Provide for the STF contracts included in GRID.

1.13 Please provide a table showing the actual generation of each PacifiCorp coal, gas, hydro and wind generating unit modeled in GRID for each month for the period 2003 to the present. Please provide this information electronically in excel spreadsheets with all formulas intact.

1.14 Please provide hourly generator logs for each wind, coal, gas and hydro unit modeled in GRID for the Four-Year Period as defined above. Please provide this information electronically in excel spreadsheets with all formulas intact.

1.15 For the Four-Year Period, please provide hourly logs for the following contracts/resources modeled in GRID. Please provide in excel format :

a. the Mid Columbia hydro contract;

b. all BPA contracts;

c. all wind resources; and

d. each long-term purchase or sale contract.

1.16 Please provide all documents concerning the development of test year wheeling expenses modeled in GRID. Provide supporting data including historical costs (including transaction level) used to develop test year projections, <u>and all information and analysis used to develop escalation rates used.</u>

1.17 Please provide the document Regulatory Fuel Budget filing used for the test year. Please provide the equivalent of PacifiCorp's response to ICNU data requests 14.3-2 Confidential from UE 191.

1.18 Please provide the heat rate curves for each resource modeled in GRID and workpapers used to develop the curves.

1.19 Please explain in detail the process used to compute the hourly shapes for wind Please provide the actual hourly breakdown of allocated spinning reserves, ready reserves, and regulating margins for the four year period. Provide in the same format as PacifiCorp provided in responses to OPUC 3 and OPUC 3 Supplemental from Oregon Docket No. UE 191.

1.20 Please identify all call option contracts included in GRID.

1.21 Please provide the actual most current schedule for thermal and hydro generator planned outages for 2009, 2010, 2011 and 2012. Note that the relevance of this request is tied to the fact that in recent cases the Company has used projected planned outages for purposes of computing planned outage requirements in GRID for certain resources.

1.22 Please provide workpapers and documentation supporting the "Other Cost" file used in GRID. Include all electronic spreadsheets used to compute any of the line items in the file.

1.23 Please provide workpapers and documentation supporting the "Energy Cost" file used in GRID. Include all electronic spreadsheets used to compute any of the line items in the file.

1.24 Please provide workpapers and documentation supporting the "Demand Cost" file used in GRID. Include all electronic spreadsheets used to compute any of the line items in the file

1.25 Please provide workpapers and documentation supporting the "Demand" file used in GRID. Include all electronic spreadsheets used to compute any of the line items in the file

1.26 Please identify all financial archetypes modeled in the GRID study(s) filed in this case. Please provide workpapers and documentation supporting the supporting data used in GRID. Include all electronic spreadsheets used to compute any of the associated inputs.

1.27 Please provide the real time thermal unit operating characteristics comparable to GRID inputs.

1.28 Please provide the same information as requested in the prior question but for hydro units.lease provide GRID hydro weekly input files based on 40 water years rather than wet, median, and dry hydro cases.

1.29 For all Call Option purchase contracts modeled in GRID, please provide any extrinsic value used in the economic evaluations of these projects for the CY 2009 test year.

1.30 Provide electronic copies of all purchase and sales contracts modeled in GRID.

1.31 Concerning the lines "Mark to Market", "Gas Swaps", "Clay Basin Gas Storage", and "Pipeline Reservation Fees" modeled in GRID, please describe what each one of these are, provide workpapers electronically detailing the basis for these costs, and showing the calculations performed to develop the projections of costs for the test year period.

1.32 Has the Company changed any maximum capacities, minimum up or down times or unit minimum capacities for thermal or hydro generators modeled in GRID since the last Oregon TAM case. If so, identify each such instance, explain why the change was made and provide supporting documentation.

1.33 Please provide all workpapers explaining the development of each line of load adjustments presented on the Company's Grid output reports. These include but are not limited to:

BPA Hermiston Losses
DSM (Irrigation)
MagCorp Curtailment
Monsanto Curtailment
Station Service

1.34 Provide data for the four year period 2004-2007 for all 3rd party transmission imbalance transactions that have been included in STF or secondary transactions in the Actual Power Cost reports during that period.

1.35 Provide data for the four year period 2004-2007 for all non firm transmission transactions that have been included in the Actual Power Cost reports during that period.

1.36 Please provide access to the GRID model and supporting input data.

Exhibit ICNU/114
Minimum Filing Requirements for GRID Updates and Rebuttal or Surrebuttal

1. Provide access to the final updated, or rebuttal GRID model and supporting input data.

2. For each adjustment made to GRID in updating (if applicable) the NVPC study or in preparing rebuttal or surrebuttal runs, please provide the following:

   a. GRID scenario description
   b. GRID annual power cost report and energy reports, and hourly diagnostic reports.
   c. Same reports as above for the comparison scenario
   d. Calculation of the adjustment amount
   e. For each change in inputs that have been made from Company's filed inputs, please identify the specific entries in the input
   f. For each change in inputs that have been made from the comparison scenario, please identify the specific entries in the input
   g. All workpapers and supporting for the adjustment and changes to inputs.

UE-199/PacifiCorp
June 4, 2008
ICNU 6th Set Data Request 6.6

ICNU Data Request 6.6

Please refer to ICNU DR 4.26. Please reconcile the TY 2009 NPC forecast with the figures provided in the response to ICNU DR 4.26.

Response to ICNU Data Request 6.6

The Company's response to ICNU Data Request 4.26 incorporated objections from ICNU Data Request 2.8 and ICNU Data Request 4.25. The Company incorporates these objections into this response to the extent applicable. Specifically, the Company objects to this request to the extent it seeks information or materials covered by the attorney-client privilege or work-product privilege. The Company's net power cost budget reflects the Company's assessment of pending and anticipated regulatory litigation. For this reason, assumptions underlying the budget may implicate privileged information.

Without waiving these objections, the Company responds that, in light of the market conditions that the Company has experienced in 2008 and now expects to experience in the summer of 2008, the 2009 budgeted power costs from November 2007 are understated by a significant amount.

UE-199/PacifiCorp
June 4, 2008
ICNU 6th Set Data Request 6.1

ICNU Data Request 6.1

Please refer to PPL/201. Please explain why the Company is using year 2007 forecasted sales for development of Schedule 200 rather than Year 2009 projected sales.

Response to ICNU Data Request 6.1

The Company used the billing determinants from its most recently approved general rate case, Docket UE-179, to develop the proposed TAM adjustment in this case. This is consistent with the prior TAM filing approved in UE-191. The Company did not consider it appropriate to use billing determinants from a test period that has not been reviewed or approved under the context of a general rate case.

UE-199/PacifiCorp
April 21, 2008
ICNU 1st Set Data Request 1.46

ICNU Data Request 1.46

Refer to PPL/102, page 2. Does the Company agree that, to be consistent with the call option treatment adopted in UE 191, it should remove the June 2009 demand charge from the Morgan Stanley call option contract (P272158) because it does not dispatch in that month. If not, please explain why not.

Response to ICNU Data Request 1.46

See Response to ICNU Data Request 1.43. If and when ICNU or another party proposes an adjustment to the Morgan Stanley call option contract, PacifiCorp will need to evaluate the specific adjustment proposed and determine whether it is reasonable in light of the facts and circumstances of this case.

07-035-93/Rocky Mountain Power
March 11, 2008
CCS 15th Set Data Request 15.2

CCS Data Request 15.2

NPC GRID Modeling. Reference CCS 2.63-1. Please explain how the figure 75,000 (cell V4) was derived.

Response to CCS Data Request 15.2

The 75,000 value was estimated based upon information available at the time between how much was delivered and how much was metered.

07-035-93/Rocky Mountain Power
January 31, 2008
CCS 5th Set Data Request 5.1

CCS Data Request 5.1

NPC GRID Modeling. MDR-2.57 contains a worksheet that lists considerations related to planned outage scheduling. It states the cold weather/high load months are to be avoided for planned outages for Hunter, Wyodak and other plants, and that the period late November through mid February are to be avoided. However, the GRID data base shows planned outages for Cholla, Craig, Hayden, Hunter and Naughton in the months of January and February 2009. Further, during the four-year period ended June 2007 none of these units actually had outages scheduled in January or February. Given the criteria delineated in the worksheet provided as part of MDR-2.57, does the Company believe that the normalized outage schedule included in the GRID database is reasonable?

Response to CCS Data Request 5.1

Yes. For normalized ratemaking purposes, GRID is required to schedule planned outages for all plants during a one year period. To do otherwise would result in planned outages at certain generating units being ignored in the determination of normalized power costs. In actual practice, planned outages can be staggered across multiple years; however this cannot be reflected in GRID without skewing normalized power costs.

In developing the normalized outage schedule for GRID, the Company ensures that (1) the months of July and August have no scheduled maintenance; (2) the overlapping of unit outages is minimized; and, (3) outage periods include as much time over the weekend as is possible given the length of the outages defined by the 48-month period.

UE-199/PacifiCorp
May 16, 2008
ICNU 4th Set Data Request 4.6

ICNU Data Request 4.6

In the response to ICNU 2.1, the Company confirmed that it changed the methodology for computing the Currant Creek outage rate. The Company discussed use of the outage rate for the Steam Generator for the entire plant in that answer.

a. Please confirm that there were actually two changes to the methodology used to compute Currant Creek unplanned outage rates.

b. Please confirm that the Company has now abandoned its long-standing practice of using "generic" outage rates to fill in missing months for units when less than a full 48 months of outage data is available. For example, in the past, if only 24 months of history was available the Company normally used a weighted average between the actual 24 month EFOR and the generic EFOR.

c. Please explain the reasoning behind this change in approach, and why the Company now considers it to be reasonable.

Response to ICNU Data Request 4.6

The calculation of Currant Creek's outage rates inadvertently missed the weighting of "generic" and actual outage rates.

UE-199/PacifiCorp
May 16, 2008
ICNU 4th Set Data Request 4.7

ICNU Data Request 4.7

Please confirm that the prior PacifiCorp methodology for dealing with plants having less than 48 months of actual data discussed in ICNU 4.6 was employed for Currant Creek in Docket No. UE 191.

Response to ICNU Data Request 4.7

Yes.

UE-199/PacifiCorp
June 17, 2008
ICNU 8th Set Data Request 8.1

ICNU Data Request 8.1

In GRID the Company assumes the weekend outage rate applies for a period of 56 hours, starting at 10 pm on Friday nights. However, review of the data provided in ICNU DRs 1.6-1 and 1.6-2 appears to show that the weekend outage rate is computed on the basis of a 48 hour period. Attached to this data request ("DR") is a file with information provided by PacifiCorp that includes calculations supporting this contention. If correct, this would mean that GRID uses an incorrect modeling of weekend outages. Please confirm whether the weekend outage rate is computed on the basis of a 48 hour period.

Response to ICNU Data Request 8.1

The Company is not clear about the calculations in the attachment to the request. However, upon review of the source data, the setting for 56 hours beginning on Fridays should be 48 hours beginning on Saturdays. The Company will make the correction in its update.

UE-199/PacifiCorp
April 21, 2008
ICNU 1st Set Data Request 1.42

ICNU Data Request 1.42

(a) Does GRID model any non-firm transmission flows? If not, please explain why not. (b) Also, please explain any prior requirement from avoided cost proceedings in which the Company was required to include non-firm transmission flows in GRID modeling. (c) Provide any studies the Company has filed in conjunction with these requirements and supporting workpapers.

Response to ICNU Data Request 1.42

(a) No, non-firm transmission is not known-and-measurable under normalized rate-making.

(b) The Oregon Commission has not made any prior requirement to include non-firm transmission flows in GRID modeling for any purpose. In Docket 03-035-14, the Utah Commission ordered the Company to include non-firm transmission in avoided cost modeling. Please refer to Attachment ICNU 1.42 for a copy of the Commission's order.

(c) Please refer to the Company's response to ICNU Data Request 1.69.

ICNU Data Request 2.2

GRID shows substantially more STF sales than purchases for SP15. This results in the Company purchasing balancing energy in order to cover STF sales. Please explain why this is a prudent practice.

Response to ICNU Data Request 2.2

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 but the Four Corners market is illiquid. 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 were available and it is more economical to do so.

UE-199/PacifiCorp
May 16, 2008
ICNU 4th Set Data Request 4.16

ICNU Data Request 4.16

Please refer to the answers to ICNU 2.2, does the Company use such transactions in real time operations in order to fully utilize the benefits afforded through its transaction in the SP 15 market? If so, please explain why it is reasonable to exclude non-firm transmission from Four Corners to SP 15 (or vice-versa).

Response to ICNU Data Request 4.16

Yes. The decision to balance the SP15 position utilizing transmission from Four Corners versus transacting at SP15 is made on a day-ahead basis. Non-firm transmission is not guaranteed to be available, so wheeling is not always an option and its availability is not known until the day before delivery of the power. The Company does not include non-firm transmission from Four Corners to SP15 because it is not assured to be available on a normal basis.

UE-199/PacifiCorp
May 16, 2008
ICNU 4th Set Data Request 4.10

ICNU Data Request 4.10

Does the Company agree that hedging does not reduce future costs, and instead reduces the uncertainty of future cost levels? Please elaborate.

Response to ICNU Data Request 4.10

Hedging is not intended to reduce future costs, but in execution may or may not reduce future costs. Hedging reduces the uncertainty of future costs.

Assuring a bright future for our customers





2007

Integrated Resource Plan

Appendices

PACIFICORP
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Pacific Power | Rocky Mountain Power | PacifiCorp Energy

APPENDIX J – WIND RESOURCE METHODOLOGY

This appendix summarizes the wind resource analyses used to help characterize wind resources included in PacifiCorp's IRP models. Specifically, the appendix covers (1) the expected cost of integrating various amounts of wind generation with other portfolio resources—reflecting a refinement and update of previous analysis conducted for PacifiCorp's integrated resource planning, (2) a resource screening effort to determine a base amount of wind resources to include in portfolios subjected to stochastic production cost simulation, and (3) the calculation of capacity planning contribution of wind resources, accounting for generation variability.

In addition to summarizing the results of its wind resource studies, this appendix briefly describes current efforts by organizations in the Pacific Northwest to assess wind integration implications. Finally, the last section of this appendix discusses the role of resource fuel type on the company's strategy for integrating wind resources. This discussion addresses an Oregon Public Utility Commission requirement to investigate this topic for the 2007 IRP.

A new methodology was developed to explicitly calculate the load following reserve requirement based on the uncertainty in load for the next hour on an operational basis, which allowed PacifiCorp to apply the same analytical approach to estimating the incremental reserve requirements for wind. The availability of hourly wind data for resources distributed across PacifiCorp service territories over comparable historical time horizons enabled analysts to include proxy wind resources with realistic operating characteristics into the analysis. Further, a development in techniques for estimating load carrying capability allowed analysts to estimate the capacity contributions of various wind combinations of wind developments that restricted interactions due to correlated generation from nearby plants. Analysts were able to improve the characterization of wind operations and interactions with the power system in the present analysis.

WIND INTEGRATION COSTS

Across all analyses, wind integration costs have generally been divided into two categories – incremental reserve requirements and system balancing costs. The former is related to the need for dynamic resources to be held in reserve, able to respond on a roughly ten minute basis to rapidly changing load/resource balance conditions. Since wind resource generation can be quite variable over time periods from about ten minutes to several hours, it will be necessary to increase the amount of reserves as the quantity of wind resources on the system increases. System balancing costs represent the difference in value between the energy delivered from wind resources compared to that delivered from less volatile resources. Consistent with previous studies, PacifiCorp reviewed both categories of wind integration costs: the incremental reserve requirement and the system balancing cost.

Incremental Reserve Requirements

Operating reserves are divided into categories based on purpose and on characteristics. Naming conventions for categorizing reserves by their intended purpose are not standard in the industry. Reserves held for responding to the sudden failure of generation or transmission equipment are usually called "contingency reserves". Reserves held to respond to changes in system frequency over a period of a few seconds will be referred to as "regulating reserves". Generation that can be brought on over a multiple-minute time period will be termed "load following reserves."

Wind projects are not expected to affect the need to hold contingency reserves, as there is no significant difference between wind generation and other types of generation with respect to sudden equipment failures, or other outages. The multiplicity of individual generators within a typical wind farm inherently makes them less susceptible to losing the entire output of the farm due to generator or turbine failures (but not transmission-related outages). Wind projects are subject to relatively rapid shutdown when wind speeds reach the cutout level. However, this has not been a significant problem in practice, as individual wind turbines do not tend to shut down simultaneously.

Similarly, regulating reserve requirements do not appear to be significantly affected by wind turbines[4]. The second-by-second variations in wind project output are found to be not significantly different from other generating units and the ambient fluctuations of the load. They are also not correlated with either load fluctuations, or distant wind projects.

Wind variations over periods of ten minutes to an hour are significant, and can cause operators to rapidly start up units on short notice within an hour. Fluctuations of the combined output of a collection of wind projects increases with the amount of total wind generation connected to the system.

For the 2007 IRP, a new methodology was developed to explicitly calculate the load following reserve requirement based on the uncertainty in load for the next hour on an operational basis. Operators have estimates of the behavior of loads for the next hour and move to bring on or back off resources as necessary to accommodate the expected change. Knowing that the actual load of the next hour will likely be different than the forecast and that there will be deviations within the hour, operators hold additional resources ready to respond should they underestimate the need for resources. (Generally, overestimates are not a problem, though it is an additional concern). Reserve levels are established to ensure that the shortfall can be met a minimum percentage of the time—generally around 95 percent. The methodology is graphically illustrated in Figure J.1, which shows how the load forecast changes from one hour to the next. Assuming that the range of actual outcomes for the next hour can be approximated by a normal distribution, the amount of additional reserve capability that is necessary to provide assurance of having adequate resources available at least 95 percent of the time can be calculated.

This methodology can be applied first to the system load alone and then again to the system load net of wind generation. The difference between the two results is the estimated incremental reserve requirement due to the wind resources.

[4] DeMeo, Grant, Milligan, and Schuerger, "Wind Plant Integration: Costs, Status, and Issues", IEEE Power & Energy Magazine, Vol 3 Number 6, Nov/Dec 2005, p. 41.

Figure J.1 – Load Following Reserve Requirement Illustration

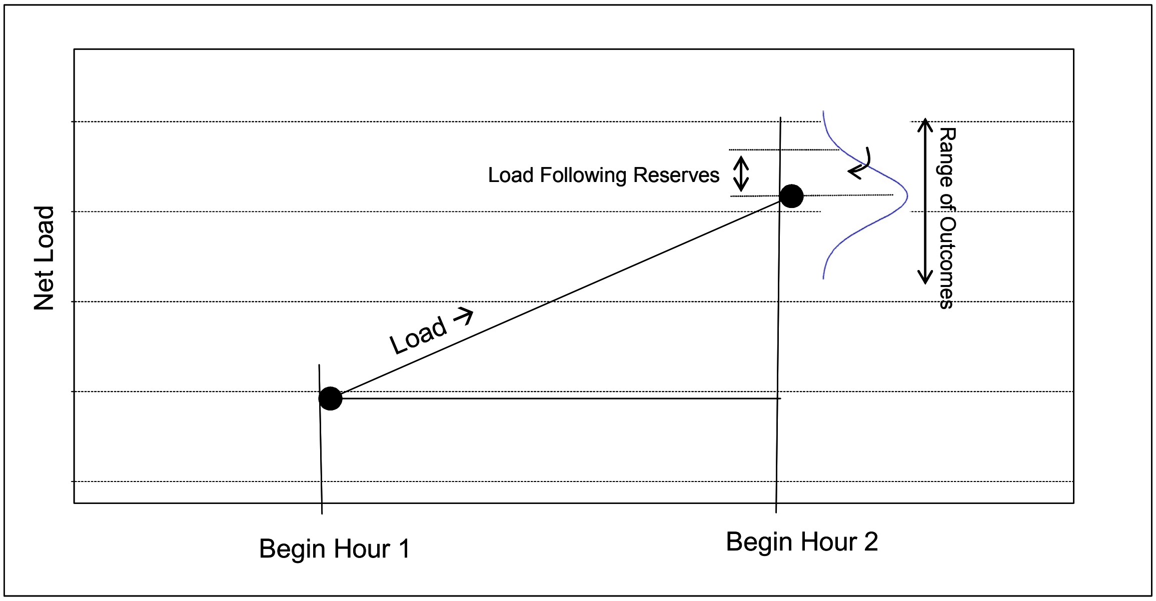
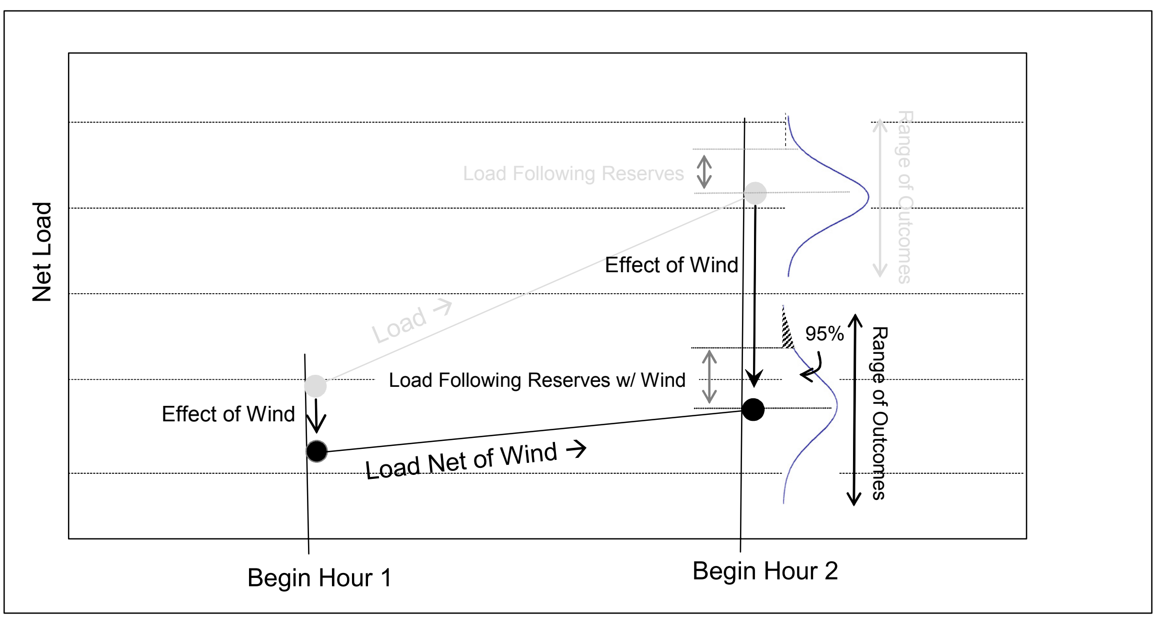


Figure J.2 shows the variability of the load forecast and the variability of the wind energy rolled together by performing the same analysis on the forecast of load net of wind energy. The expected value of load net of wind will be less than or equal to the load forecast for any given hour. However, the variability of load net of wind is greater than that of load alone. It is the difference of between the variability of load and the variability of load net of wind for a given hour that described the incremental reserves that should be attributed to wind resources.

Figure J.2 – Load Following Reserve Requirement for Load Net of Wind

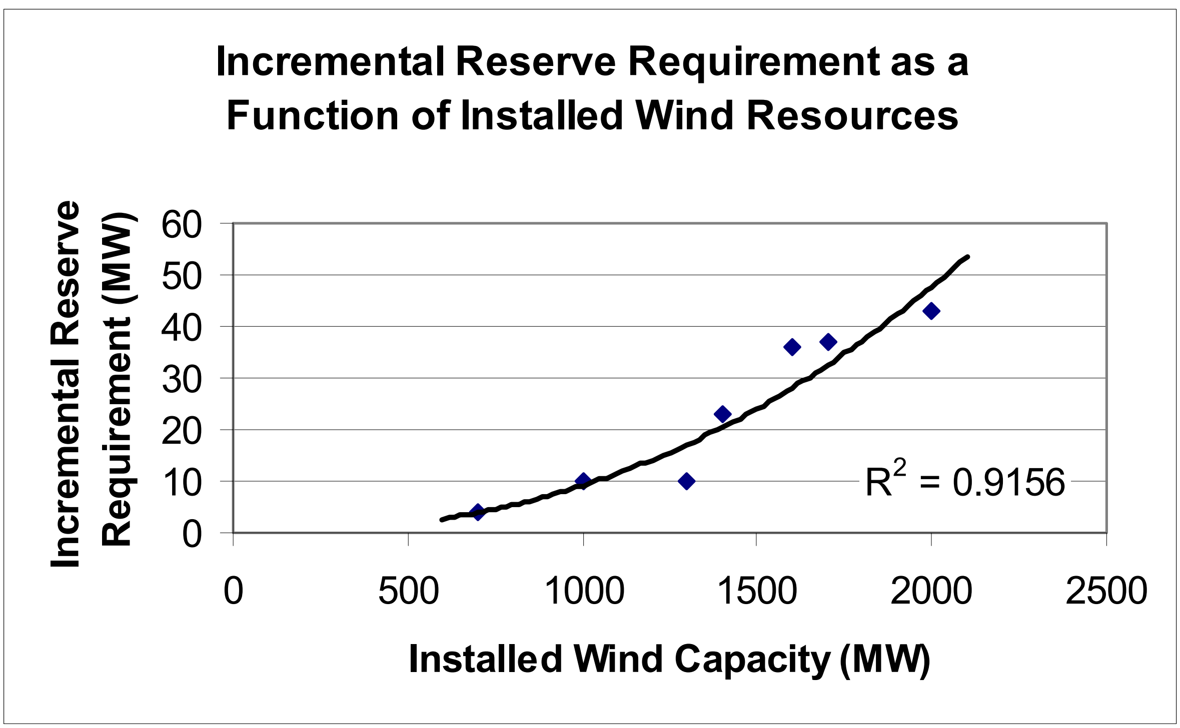


Early in the 2007 IRP process, the result of applying this methodology to the PacifiCorp system with an additional 1,400 megawatts of wind resources was an estimated 30 megawatts of additional reserve requirements. That amount of spinning reserve was added to the stochastic PaR model runs to simulate the additional cost.

In follow up analyses of the preferred portfolio, the company confirmed that using even the simplest forecast techniques greatly reduced the forecast error of both load and wind and consequently reduced the anticipated need for load following reserves. Figure J.3 displays the estimated incremental load following requirement calculated using PacifiCorp's updated load forecast and varying the level of wind resources following the build pattern of the preferred portfolio. For the 1,400 megawatt level of wind installation, the estimated need for incremental reserves is approximately 22 megawatts. For the preferred portfolio with 2,000 megawatts of wind resources, Figure J.4 shows an estimated need for 43 megawatts of additional load following reserves due to wind resources.

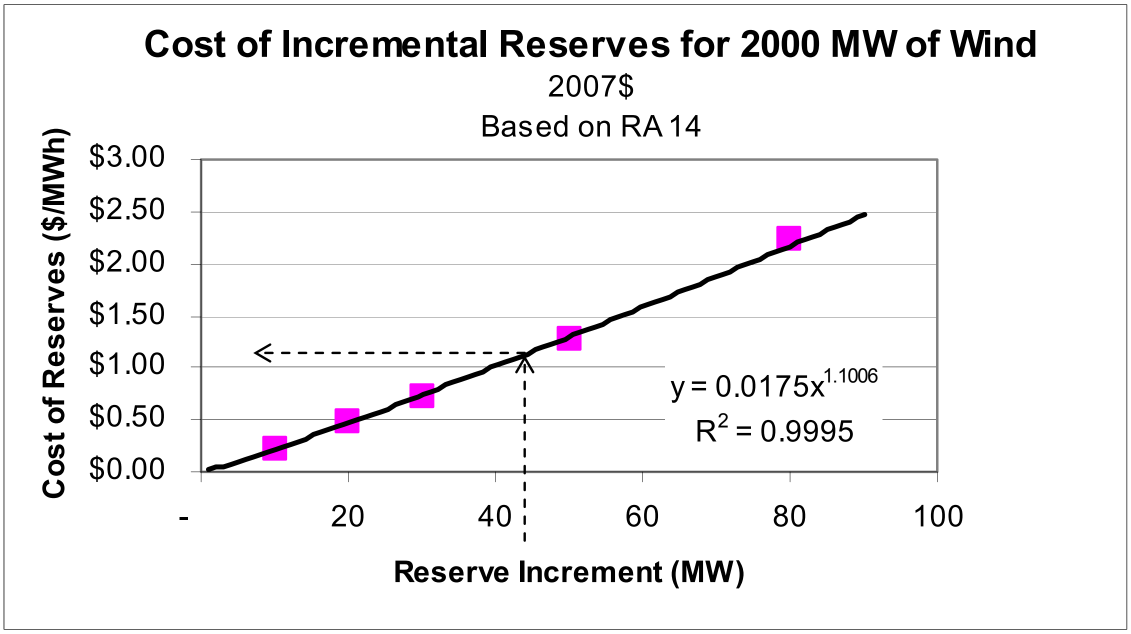
This analysis represents a reduction in the estimate of needed reserves compared with previous estimates. The major difference from prior studies is the development of a systematic method for estimating load following reserve requirements. The 2003 IRP study was based on the hourly variability of wind resources, whereas the current analysis is based on the hourly uncertainty in generation. It is further benefited by the more extensive operating data available since the 2003 study.

Figure J.3 – Incremental Reserve Cost Associated with Various Wind Capacity Amounts



By running the PaR model studies with and without the incremental load following reserves, the company can estimate the cost of the incremental reserves at varying levels. This can be converted to a unit cost by dividing the cost by the total amount of wind energy. Figure J.4 shows the results of those studies.

Figure J.4 – Operating Cost of Incremental Load Following Reserves



From Figure J.4, the unit cost of 43 megawatts of incremental reserves attributed to the 2,000 megawatts of wind capacity in the preferred portfolio is estimated to be $1.10 per megawatt hour of wind energy.

System Balancing Costs

System balancing costs represent the additional operating costs incurred as a result of adding wind generation to PacifiCorp's system. For the 2003 IRP, the system balancing costs associated with wind resources were evaluated by comparing one model run with wind resources specified with an hourly energy pattern to another run where the hourly wind energy was replaced by an equal amount of energy expressed as a flat annual shape. This methodology was repeated for the 2007 IRP preferred portfolio with the following modifications.

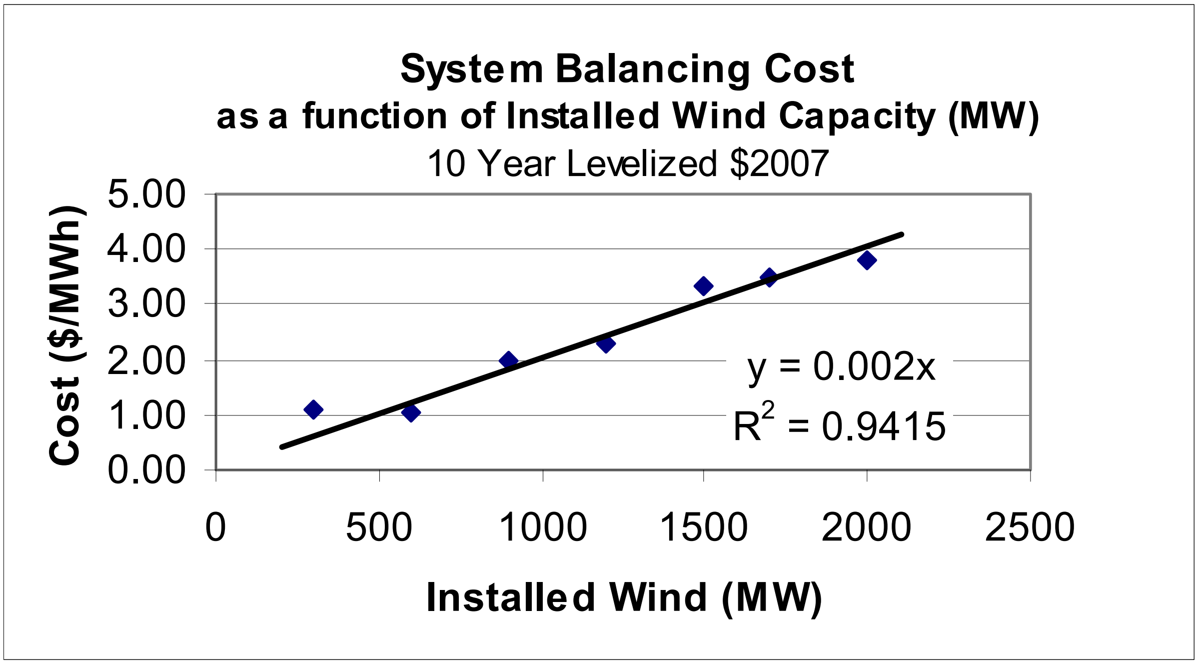
- First, the hourly wind patterns for the base study were substantially upgraded. Data from multiple Pacific Northwest sources, including PacifiCorp's actual wind energy, was modified for project size and mapped to the proxy wind resources by location. In the case of multiple "plants," some of the data was shifted by an hour or two to represent diversity within a wind area. The Wyoming projects were updated to a 40 percent capacity factor to be consistent with actual information coming from that area.

- The comparison to the annual block size was repeated for several sized accumulations of wind projects across PacifiCorp's system using the wind data and build patterns consistent with the preferred portfolio analysis.

Using the equivalent annual block against the hourly wind patterns confirmed earlier findings that as wind resources accumulate the system balancing costs also increase on a unit cost basis.

The 2007 IRP results are shown in Figure J.5. The results are similar to previous studies.

Figure J.5 – PacifiCorp System Balancing Cost



From Figure J.5 it can be seen that 2000 megawatts of wind capacity installed on PacifiCorp's system brings with it approximately $4.00 per megawatt-hour less than an equivalent amount of energy shaped as an annual base load resource

While some of the regional studies employed smaller sized energy blocks for similar comparisons, PacifiCorp continues to use the annual block-size approach. Equivalent energy generated at a constant rate for the entire year and priced at market is the competing resource that PacifiCorp uses in its resource economic evaluations.

<u>Use of Wind Integration Cost Estimates in the 2007 IRP Portfolio Analysis</u>

Wind integration costs for the purposes of the CEM runs were based on 2004 IRP results due to the timing of the needed analyses. In the PaR model, the system balancing costs are implicit as the wind resources are represented as hourly generation patterns from the quasi-historical data. The incremental load-following reserve requirement, calculated outside of the main IRP models, was added as a constraint in the stochastic PaR runs for the candidate and preferred portfolios in the 2007 IRP. (CEM does not model reserve requirements, and so was not affected by the analysis).

Because the hourly generation patterns of wind and the increased incremental reserves are modeled explicitly in the PaR model the PVRR includes both types of cost. The integration cost for the 2,000 megawatts of wind resources included in the preferred portfolio is estimated to be $5.10 per megawatt hour of wind energy.

PacifiCorp is continuing to explore methodologies to confirm and quantify wind variability with respect to the need for operating reserves. In particular, sub-hourly data is being captured to test the impact of deviations within the hour. Continued study of the impacts of integrating large quantities of wind in PacifiCorp's system is identified in the IRP action plan (See Chapter 8).

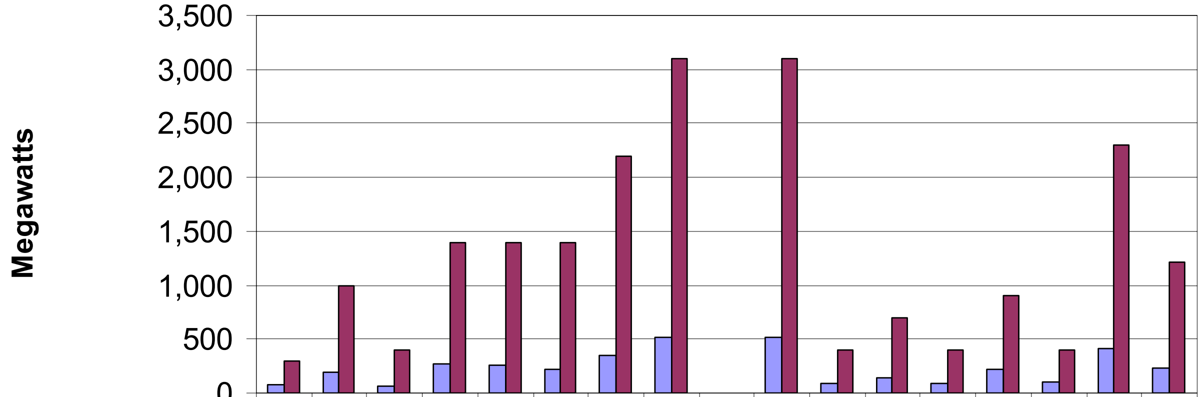
DETERMINATION OF COST-EFFECTIVE WIND RESOURCES

PacifiCorp used the CEM to help determine the quantity of wind considered reasonable given a range of alternative assumptions concerning future portfolio costs. The explicit costs of wind (capital and integration costs, less production tax credits and the value of renewable energy credits) were entered into the CEM. The results of the alternative future scenario CEM runs were examined to find a rough cost-effectiveness order for the proxy wind resource sites. Nearly all of the CEM runs found wind to be part of a cost-effective resource portfolio.

Fixed in each of the runs were the 400 megawatt MEHC acquisition commitments made to state commissions. In the "medium case" alternative future scenario (Alternative Future #11), the CEM added 700 nameplate megawatts of wind resources to the system, for a total of 1,100 megawatts of additional renewable resources by 2016.

Figure J.6 shows the cost-effective wind capacity amounts (both nameplate and capacity contribution) selected by the CEM for each of the 16 alternative future scenarios. The average for all the alternative future runs was over 1,200 megawatts (235 megawatt capacity contribution), or 1,600 megawatts including the 400 megawatt base assumption quantity. These results are consistent with the 1,400 megawatt determination for the level of cost-effective renewables reported in PacifiCorp's 2004 IRP.

Figure J.6 – Renewables Capacity Additions for Alternative Future Scenarios



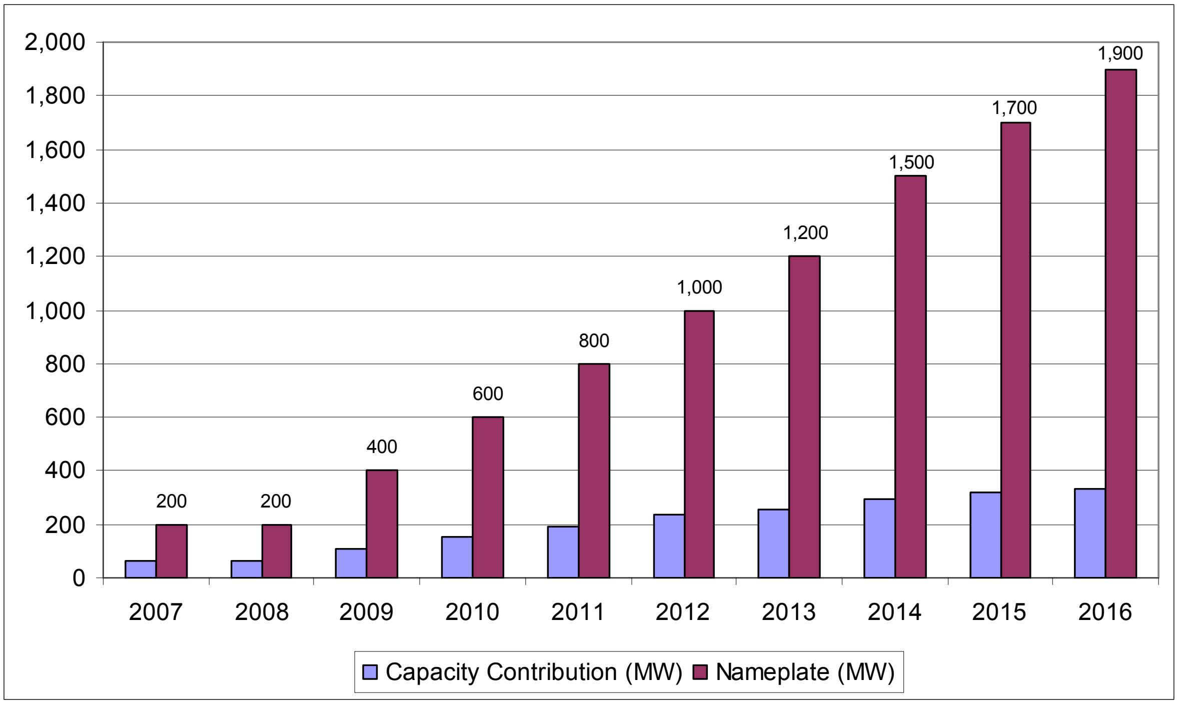
	CAF00	CAF01	CAF02	CAF03	CAF04	CAF05	CAF06	CAF07	CAF08	CAF09	CAF10	CAF11	CAF12	CAF13	CAF14	CAF15	Ave.
Wind Capacity Contribution	82	196	60	277	259	215	354	514	0	514	85	148	95	222	99	410	235
Renew ables Nameplate	300	1,000	400	1,400	1,400	1,400	2,200	3,100	-	3,100	400	700	400	900	400	2,300	1213

A CEM sensitivity run was performed to test the quantity of wind selected given the expiration of renewable production tax credits, but with otherwise favorable scenario conditions for wind development. These favorable conditions included a high CO_2 adder ($25/ton in 1990 dollars), high natural gas and electricity prices, and a high system-wide renewable sales percentage requirement attributable to renewable portfolio standards. See Chapter 6, Modeling and Risk Analysis Approach, for more details on scenario assumptions.

In this sensitivity, the CEM selected 1,900 megawatts of wind by 2016 (capacity contribution of 335 megawatts). Figure J.7 shows the cumulative annual resource addition pattern for 2008 through 2016. The sensitivity results indicate that given the assumed favorable scenario conditions, the expiration of the production tax credits results in 1,200 megawatts less wind capacity selected for the optimal portfolio.

Based on these results, PacifiCorp identified 1,000 to 1,600 megawatts of additional nameplate wind capacity for specifying proxy renewable resources to be included in portfolios subjected to stochastic production cost simulation.

Figure J.7 – Cumulative Capacity Contribution of Renewable Additions for the PTC Sensitivity Study



WIND CAPACITY PLANNING CONTRIBUTION

For planning purposes, most resources are assumed to contribute their nominal (or "nameplate") capacity to meeting the planning reserve margin level. It is recognized that wind resources cannot be depended on to contribute their full nameplate capacity to meeting planning reserve margin, since the probability of achieving that level on a peak hour is relatively low, and virtually zero for a large portfolio of diverse wind resources. Nevertheless, it was recognized that some level of capacity contribution attributed to wind projects is appropriate, and PacifiCorp has adopted the effective load carrying capability of wind projects as the standard. In short, the effective load carrying capability of a resource is the amount of incremental load the system can meet with the incremental resource without degrading the reliability of meeting load.

PacifiCorp used the stochastic PaR model to estimate the monthly load carrying capability of a wind resource using an analytical method based on the Z statistic.[5] The analytical method of estimating load carrying capability was necessary in order to compute the capacity contributions from a large number of wind projects and different combinations of projects. The result of this analysis as applied to the proxy (100-megawatt) wind resources is shown in Table J.1 below. Key observations from these results include the following.

[5] See, Dragoon, K., Dvortsov, V, "Z-method for power system resource adequacy applications" IEEE Transactions on Power Systems (Volume 21, Issue 2, May 2006), pp. 982 – 988.

- The incremental capacity contribution within an area declines due to correlations (lack of diversity) among wind projects in an area.
- The capacity contribution decline is greatest for projects with more variability of their on-peak contributions.
- The capacity contribution varies over the year, primarily due to expected on-peak generation.

Table J.1 – Incremental Capacity Contributions from Proxy Wind Resources

Regional Resource Additions (MW)		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NC OR	-100	1	18	28	17	25	35	37	27	22	14	5	5
	-200	0	8	16	7	14	24	28	18	12	5	0	0
	-300	0	0	3	0	3	14	19	10	2	0	0	0
	-400	0	0	0	0	0	3	10	1	0	0	0	0
SE WA	-100	19	14	33	13	13	10	12	7	10	14	16	16
	-200	8	2	20	2	1	0	2	0	0	3	5	4
	-300	0	0	8	0	0	0	0	0	0	0	0	0
	-400	0	0	0	0	0	0	0	0	0	0	0	0
EC NV	-100	18	20	32	32	23	28	27	23	21	23	19	28
	-200	15	17	29	26	20	24	23	20	17	20	17	24
	-300	13	14	25	20	16	20	20	18	13	16	14	21
	-400	10	12	21	14	13	17	16	15	9	13	12	17
SE ID	-100	26	37	59	35	31	32	25	32	22	32	38	32
	-200	20	31	53	29	26	27	21	28	17	26	32	26
	-300	14	24	47	24	22	22	17	24	13	21	25	20
	-400	8	17	41	18	17	17	13	20	8	16	18	14
WC UT	-100	13	10	25	31	35	27	20	26	26	24	20	19
	-200	10	9	21	27	31	24	18	22	22	20	17	16
	-300	7	7	17	22	26	20	15	18	18	16	14	13
	-400	4	6	13	17	21	17	12	15	13	13	11	10
SW WY	-100	33	27	36	33	30	30	23	24	25	31	24	34
	-200	27	24	29	27	26	25	20	21	22	26	21	28
	-300	21	20	22	21	21	21	18	18	19	21	18	22
	-400	16	16	15	16	16	16	15	16	16	16	15	16
	-500	10	12	8	10	11	11	13	13	13	11	13	10
	-600	5	8	1	4	6	7	10	10	9	6	10	4
	-700	0	5	0	0	2	2	7	7	6	1	7	0
SC MT	-100	42	34	35	24	26	26	27	26	28	32	42	33
	-200	34	27	26	19	23	21	24	23	24	28	33	26
	-300	26	20	18	14	19	16	21	20	21	23	25	18
	-400	18	14	10	9	15	11	18	18	18	19	17	11
SE WY	-100	35	26	30	25	22	19	13	15	18	23	44	37
	-200	30	21	24	21	18	16	11	13	15	18	43	32
	-300	25	16	19	17	14	12	9	10	11	13	43	27
	-400	20	12	13	13	10	9	7	8	7	9	42	23
	-500	15	7	7	9	6	6	5	6	3	4	41	18
	-600	9	2	2	5	2	3	3	3	0	0	40	13
	-700	4	0	0	1	0	0	1	1	0	0	39	8

REGIONAL STUDIES

Utilities are studying wind resources in order to quantify the full cost of integrating wind energy into existing systems. In March 2007, Northwest Power and Conservation Council released the Northwest Wind Integration Action Plan (the Action Plan). A joint product of the region's utility, regulatory, consumer and environmental organizations, the Action Plan addresses several major questions surrounding the growth of wind energy and suggests areas that need further consideration.

The Action Plan summarizes the results of wind integration cost studies performed by PacifiCorp (in its 2004 IRP), Avista, Idaho Power, Puget Sound Energy, and Bonneville Power. The report lists the key findings of these northwest studies. All of the studies find that the cost of integrating wind starts low as the variability of small quantities of wind generation is lost in the volatility of the system load, and grows as the amount of wind resource increases. Collectively the studies list the size of the control area in relation to the amount of wind, the geographic diversity of the wind locations, the amount of flexibility of the receiving utility, and the access to robust markets as key factors affecting the cost of integrating wind energy.

Table J.2 reproduces the data from the report. The Action Plan includes a summary of each of the study methodologies in its appendix B. PacifiCorp's estimate of wind integration costs ranked among the lowest of the wind integration costs. Only Bonneville Power ranked lower. PacifiCorp's low integration cost is likely the result of the opportunity to maximize the use of each of the key factors: a large system, wide geographic coverage allowing for dispersed wind sites, and a flexible system with multiple points of access to the energy markets.

Table J.2 – Wind Integration Costs from Northwest Utility Studies [6]

Utility	Peak Load (MW)	Wind Penetration ($/MWh of Wind Generation)			
		5%	10%	20%	30%
Avista	2,200	$ 2.75	$ 6.99	$ 6.65	$ 8.84
Idaho Power	3,100		$ 9.75	$11.72	$16.16
Puget Sound Energy	4,650	$ 3.73	$ 4.06		
PacifiCorp (2003-2004 IRP)	9,400	$ 1.86	$ 3.19	$ 5.94	
BPA (within-hour impacts only)	9,090	$ 1.90	$ 2.40	$ 3.70	$ 4.60

In the wake of the regional load peak of July 24, 2006, when wind turbines made only a small contribution to generating capacity at the time of the peak, the wind resource contribution to peak capacity is being reassessed by Northwest Resource Adequacy Forum (NWRA Forum) as Action #1 of the Action Plan.[7]

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[6] Source: NWRA Forum, Northwest Wind Integration Action Plan, (March 2007 pre-publication version), page 31.
[7] NWRA Forum, Northwest Wind Integration Action Plan (March 2007, pre-publication version). See Action 1, p.48,

EFFECT OF RESOURCE ADDITION FUEL TYPE ON THE COMPANY'S COST TO INTEGRATE WIND RESOURCES

As the company installs larger volumes of wind resource generation, the cost to integrate these intermittent resources is anticipated to increase. This is because more non-wind resources must be held back to allow flexibility to follow the intra-hour volatility of the wind generation. Resources with greatest the dispatch flexibility that are not already in use to serve load are typically used for integration.

The hour to hour dispatch of non-wind resources is not a trivial decision. The company's owned hydro plants with storage capability and the Mid-Columbia hydro contracts, all of which have the highest flexibility, can often provide the needed flexibility. However, these hydro resources do not have enough volume to integrate all of the anticipated wind variability. Partially loaded gas turbines can provide additional flexibility. Due to its low cost, coal is normally fully utilized to serve load rather than backed off to provide wind integration.

It is flexible resources that are operating on the margin that influence the cost of wind integration. When evaluating the effect of the fuel type of resource additions on PacifiCorp's cost to integrate wind resources, it is most likely that the IRP natural gas-fired additions will have the most effect on integration costs.