Witness CCS -6

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In The Matter Of The Application	**:**	**Docket No. 04-035-42**
Of PacifiCorp For Approval Of Its	**:**	**Direct Testimony Of**
Proposed Electric Rate Schedules	**:**	**Randall J. Falkenberg**
& Electric Service Regulations	**:**	**For The Committee of**
	:	**Consumer Services**

REDACTED

3 December 2004

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 Committee of Consumer Services.

Q. WHAT CONSULTING SERVICES ARE PROVIDED BY RFI?

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

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in CCS Exhibit 6.1 attached to my testimony.

I. INTRODUCTION AND SUMMARY.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. My testimony addresses PacifiCorp’s GRID[1/] model study of normalized net power costs for the projected test period, April 2005 to March 2006. I identify a number of problems in the GRID study that overstate the Company’s Utah revenue requirement.

1/ Generation and Regulation Initiatives Decision Tool

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have included Table 1 at the end of my summary, which illustrates my recommended test year net power cost and other revenue requirement adjustments. My major findings are as follows:

1. PacifiCorp's request for $745.2 million in (Total Company) net power costs is substantially overstated. I recommend a number of net power cost adjustments, resulting in a reduction to Utah's allocated net power costs. Table 1 shows the dollar impact of each of my proposed adjustments and the approximate Utah allocation.

<u>West Valley Lease and Gadsby CT Fixed Costs</u>

2. In its evaluation of the West Valley lease, PacifiCorp used Black-Scholes modeling and ascribed a substantial "option value" to the project. However, this benefit cannot be reflected in GRID. Without this assumed benefit, West Valley would have been an uneconomic resource for the Company.

3. While the West Valley lease contains an early termination clause, the Company failed to make a prudent effort to take advantage of it. RFP 2003-A provided the best opportunity to obtain the least cost replacement for West Valley. However, the Company only exercised the early termination option after pressure from regulators and ratepayer representatives in May 2004. Consequently, the Company missed the best opportunity to replace the West Valley lease. Even the RFP 2004-X solicitation for a West Valley replacement was biased in favor of continuing the lease. As a result, I include an imprudence disallowance in the West Valley adjustment shown in line 1 of Table 1.

4. PacifiCorp obtained a $7.5 million concession from General Electric ("GE") when it negotiated the Gadsby combustion turbine purchase. This credit was realized as a waiver of combustion turbine rental fees, but not as a reduction to the cost of the project. By structuring the credit in this manner, the Company retained the benefit for shareholders instead of customers. I recommend a rate base offset in this amount because the Company had a conflict of interest in its negotiation for this concession and customers are entitled to the credit for this high cost resource. This adjustment is shown in line 2 of Table 1.

Short-Term Firm Transaction Adjustments

5. PacifiCorp excludes more than 80% of its typical short-term firm transaction volume in GRID because it uses only transactions arranged before the filing date, rather than projected transactions. This results in an overstatement of net power costs. I recommend the Commission direct the Company to convene a task force to develop a more reasonable method for projecting short-term firm transactions in the next case.

6. The limited sample of short-term firm transactions included in GRID has a preponderance of below market trades. This occurred because market prices increased after the trades were made. This increases net power costs. One would not expect the Company to consistently make below market sales under normalized conditions. I have adjusted the price of all transactions to conform to the Company's March 31, 2004 forward price curve used in preparation of the test year. This adjustment is shown on Table 1, line 3.

Long Term Contract Adjustments

7. The Company only models the costs of the System Integrity curtailment clause for the P4 contract, but none of the capacity or curtailments. To provide a balanced treatment, I propose an adjustment matching the costs and benefits of this contract. This adjustment is shown on line 4 of Table 1.

8. PacifiCorp has entered into a multi-year Aquila hydro hedge. However, GRID includes only the premium cost of the hedge while ignoring the benefits. The Company proposes to address this problem via a balancing account. To date, no state has adopted this type of ratemaking treatment. I recommend removal of this Aquila hedge from GRID and rejection of PacifiCorp's proposed balancing account. This reduces net power costs by the amount shown on line 5 of Table 1.

9. PacifiCorp overstates generation from the Fort James cogeneration facility compared to recent actual levels. Correcting this error reduces net power costs by the amount shown on line 6 of Table 1.

10. The Commission should also reduce the estimated payments for an incentive contract with the Kennecott on-site generator to correct an error in the Company's filing. This reduces net power costs by the amount shown on line 7 of Table 1.

11. Committee witness Hayet testifies that PacifiCorp has used outdated assumptions related to the US Magnesium and Desert Power contracts, which increase net power costs. He also recommends that two new QF contracts should be included in

GRID. His adjustments are reflected on lines 8, 9, and 10 of Table 1.

Modeling Adjustments

12. GRID produces an unrealistic dispatch of gas-fired peaking units. The model limits the gas units to operate at minimum loading levels. This unrealistic operation does not occur in actual practice. This problem stems from an incorrect modeling of operating reserves on the system. Correcting this problem reduces net power costs by the amount shown on line 11 of Table 1.

13. The Vista hydro modeling methodology overstates the likelihood of extreme hydro conditions while understating the chances of more typical conditions. Correcting this problem reduces net power costs by the amount shown on line 12 of Table 1.

Outage Adjustments

14. The Company uses actual outages over the most recent 48-month period to develop outage rate estimates in GRID. Over the past five years, outage rates for PacifiCorp units have substantially increased, resulting in much higher net power costs. I recommend a series of outage rate adjustments to correct errors, remove imprudent outages and to provide more representative net power cost estimates.

15. While PacifiCorp claims to have removed the impact of the Hunter outage from net power costs, it did not do so completely. The Company erroneously deducts Hunter outage hours from the service hours used in computing the outage rates for the unit. Correcting this problem reduces net power costs by the amount shown on line 13 of Table 1.

16. The Company assumes Swift Unit 2 will be out of service for the entire test period owing to the collapse of its diversion canal in April 2002. This was a very unusual event that is unlikely to ever reoccur. The Company expects the unit to begin generation prior to the start of the test year and to resume a normal operating level by January 1, 2006. To date the Company has not reflected this known and measurable change in net power cost studies in any other state. I recommend net power costs be computed assuming full operation of Swift Unit 2 in the test year, resulting in the adjustment shown on line 14 of Table 1.

17. GRID uses overstated outage rates for its new Gadsby and West Valley Combustion Turbine Units ("CTs"). The Company included numerous outages that occurred during their initial operation and testing. Such outages should not be expected to reoccur in the

future. I recommend use of a mature forced outage rate for these units, reducing net power costs by the amount shown on line 15 of Table 1.

18. The Company also included inappropriate outages for other plants in its historical data. For example, PacifiCorp included an outage at Bridger Unit 4 (line 16 Table 1) that the Company has already admitted was due to a mistake of its own making. It also included other outages and derations relate (line 17 Table 1) and Blundell generating stations (line 18 Table 1). The impact of these outages should be reversed as well, which reduces net power costs by the amounts shown on lines 16-18 in Table 1.

19. I further recommend the Commission reverse two abnormal or "catastrophic" outages at Hayden Unit1 and Colstrip Unit 4 to provide a better representation of normalized net power costs. The Company previously proposed excluding these two outages in prior cases in Oregon and Wyoming. Reversing these outages reduces net power costs by the amount shown on lines 19 and 20 of Table 1.

20. The Company also includes many minor outages that it reported to NERC as being caused by errors of Company personnel or contractors. I recommend the Commission remove the impact of these events. This reduces net power costs by the amount shown on line 21 of Table 1.

<u>Other Related Adjustments</u>

21. I recommend a more realistic shaping of the Foote Creek wind resource, resulting in an adjustment in the amount shown on line 22 of Table 1.

22. Committee witness Hayet also recommends a loss factor adjustment in the amount shown on line 23 of Table 1.

23. PacifiCorp overstates wheeling expense by including charges related to the Southern-California Edison (SCE) ISO fees that far exceed current expectations. This adjustment reduces net power costs as shown on line 24 of Table 1.

Table 1
Summary of Recommended Adjustments
$1000

	Total Company		Est. Utah Jurisdiction
		SE	41.167%
Reference:		SG	41.908%
I. Gadsby and West Valley CT Fixed Costs	-$8,065,891		-$3,384,973
1 West Valley Lease	-$7,093,000		-$2,972,542
2 Gadsby CT Rate Base	-$972,891		-$412,431
II. GRID (Net Power Cost Issues)			
PacifiCorp Request	$745,201,205		$309,537,660
A. Short Term Transactions	-$13,386,125		-$5,609,872
3 STF Normalizing Adjustment	-$13,386,125		-$5,609,872
B. Long Term Contract Adjustments	-$6,357,709		-$2,664,395
7 P4 Production	-$486,000		-$203,673
5 Aquila hydro hedge	-$1,750,000		-$733,392
6 Fort James	-$617,132		-$258,628
7 Kennecott Reimbursement	-$280,000		-$117,343
8 US Magnesium (Hayet)	-$2,712,696		-$1,136,840
9 Desert Power (Hayet)	-$1,692,187		-$709,164
10 Kennecott/Tesoro (Hayet)	$1,180,306		$494,644
C. Modeling Adjustments	-$36,703,936		-$12,961,323
11 Reserve Modeling	-$4,824,540		(2,003,991)
12 Hydro Modeling (Vista) Adj.	-$1,346,688		(559,380)
13 Hunter Outage (Error Correct)	-$1,302,306		(540,945)
14 Swift Failure	-$5,954,265		(2,473,251)
15 CT Outage Rates	-$844,458		(350,766)
16 Jim Bridger 4 Outage	-$656,594		(272,732)
17 Hunter Transformer Outages	-$2,461,229		(1,022,332)
18 Blundell Deration	-$158,982		(66,037)
19 HDN - 1 Catastrophic Outage	-$396,757		(164,803)
20 Colstrip 4 Catastrophic Outage	-$635,847		(264,115)
21 Other Company Error Outages	-$448,426		(186,265)
22 Wind Shape Modeling	-$31,910		(13,255)
23 Loss Modeling (PMH)	-$12,141,934		(5,043,451)
24 SCE ISO Fees	-$5,500,000		-$2,304,946
Total Power Cost Adjustments -	-$56,447,771		-$21,235,590
Allowed - Final GRID Result	$688,753,434		$288,302,070
Total All Adjustments	-$64,513,661		-$24,620,563

II. NET POWER COST ISSUES

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

A**.** Net power costs are the variable production costs related to fuel and purchased power expenses and net of power sales revenue. Net power costs comprise a substantial portion of overall revenue requirement and therefore are a significant component of PacifiCorp's proposed base rates. In Docket No.03-2035-02, the Company requested $534 million (total Company basis) in net power costs. In the Stipulation in that case, the Company agreed to final net power costs of no more than $512 million.[2/] In this case, the Company is requesting $745 million.

Short-Term Transaction Modeling

Q. DESCRIBE THE SHORT-TERM TRANSACTIONS MODELED IN GRID.

A. There are two types of short-term transactions modeled in GRID. Short-term firm transactions are firm purchased sales contracts with a term less than one year. GRID does not forecast or simulate such transactions. They are just a fixed input with pre-determined energy volumes and prices.[3/]

System balancing transactions (hour-to-hour trades) are simulated in GRID. The model either sells or purchases these products at prices based on its forward market price curve as needed to balance the system.

[2/] This was the amount estimated by Mr. Widmer in a data response in the recent Washington proceeding. Based on the Committee's analysis from the prior case, the amount of net power costs embedded in the Stipulation is even less.

Q. DO YOU AGREE WITH THE GRID MODELING METHODOLOGY?

A. No. There are some serious problems with PacifiCorp's modeling approach. In this case, the Company included only the trades that it had arranged as of May 5, 2004.[4/] The Company ignores the fact that many additional transactions will be arranged after the filing date. Indeed, many will occur during the FY 2006 test year, days or only hours ahead of their actual delivery. Because the Company attempts to minimize its costs, it will naturally attempt to make profits on short-term trades wherever possible and reduce costs by achieving a better system balance. As a result, the volumes of short-term firm transactions will be understated in GRID and net power costs will likely be overstated.

Finally, because GRID does not model all short-term firm sales, it tends to overstate (non-firm) balancing transactions. In GRID it is impossible to make a profit on balancing transactions because purchase and sales prices are assumed to be equal in hourly markets. In actual practice, however, the Company will attempt to make a profit on all short-term transactions.

Q. HOW SUBSTANTIAL IS THIS PROBLEM?

A. The current filing assumes an average transaction balance (the average volume of purchases and sales) of 3.3 million mWh. In contrast, for FY 2004, the actual average short-term transaction volume balance was 17.5 million mWh. Thus, GRID excludes more than 80% of recent actual short-term firm transactions from the test year. The PacifiCorp method is

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[3/] The model *accounts* for such transactions rather than *simulates* them. No matter what else changes in the model, the short-term firm transactions will remain constant in GRID.

[4/] See CCS 8.16

systematically flawed because the Company continues to make trades as time passes, and it is safe to assume the objective of these trades is to reduce, rather than to increase net power costs. Unless one assumes all the additional activity is merely a series of "wash trades" for no real economic purpose, the net effect should be to better balance the system and lower net power costs.

Q. IS THIS A PROBLEM THAT IS INHERENT IN USE OF A FULLY PROJECTED TEST YEAR?

A. Yes. The Company's approach was obviously unrealistic from the start because it was clear that the great majority of trades would be excluded. In effect, the Company has presented what amounts to little more than a limited sample of the trades it will actually make during the test year. As I will show shortly, it is a very biased sample as well.

Q. WILL THIS PROBLEM BE SOLVED IF THE COMPANY UPDATES ITS FILING?

A. No. It is not possible in this case to include all short-term firm transactions because the test year extends well beyond the date when parties are required to file testimony. A partial update would not be an equitable solution because it will still be incomplete and any additional trades included will not be available to parties in sufficient time for analysis prior to the hearings in this case.

In addition, a complete update would require use of new forward price curves for both gas and electricity, and possibly new load forecasts and many other inputs as well. However, the Company has possession of all pertinent information and there is little to stop the Company from selectively choosing to update items that it finds to be advantageous, while ignoring all others.

Q. WHY DO YOU CONTEND THAT THE SHORT-TERM FIRM TRANSACTIONS INCLUDED IN GRID ARE A BIASED SAMPLE?

A. The Company based its filing on the March 31, 2004 forward price curve. Based on the data provided in the Company's response to CCS data request 8.32, prior to May 5, 2004 the Company entered into 33 purchase transactions and 120 sales transactions for delivery in FY 2006. These transactions were all arranged after March 2003, and most were many months *prior* to the date of the forward price curve used for balancing transactions in the preparation of the GRID study.

During the year prior to the filing date, market prices for power increased. As a result, many of the transactions executed by the Company were below market as measured by the Company's March 31, 2004 forward price curve. In fact, 65% of the purchase and 74% of the sales transactions were below market. There were only a few purchase or sales transactions that were actually above market. Most of the remaining transactions that were not below market were made around March 31, 2004. Overall, there are very few "above market" trades to balance the many below market trades made by the Company.

Q. HOW DO THESE BELOW MARKET TRANSACTIONS IMPACT NET POWER COSTS?

A. Making below market sales reduces revenues and increases net power costs. Making below market purchases reduces expense and decreases power costs.[5/] The number and volume of below market sales included by the Company in the test year far outweighs the number of below market purchases, which results in a substantial increase to net power costs.

Q. WHY IS THIS A PROBLEM?

A. First, it will not be possible to reflect all of the short-term firm transactions in the test year. This means that the additional benefits of a better balancing of the system and the numerous profit opportunities that the Company's traders will strive to exploit in the months ahead will not be reflected in rates. Consequently, the test year is biased against ratepayers.

Second, for purposes of establishing normalized rates it is unrealistic to assume that unanticipated market fluctuations will always work against the Company. In normal conditions the Company will likely make as many (if not more) above market sales, as it does below market ones. Likewise, under normal conditions, the Company will make as many below market purchases as it does above market purchases. Over time the forward price curves will move in various directions and the Company will likely find as many circumstances where it is above market as below. This being the case, it is unrealistic to assume that normalized rates should reflect a preponderance of below market transactions. Indeed, in cases prior to 2000, the Company assumed it would make a small positive margin on all short-tem firm sales transactions. For these

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5/ The reverse is true for above market transactions. However, there are very few in the test year.

reasons, use of a skewed sample of the actual short-term firm transactions will not provide a reasonable estimate of net power costs.

Finally, the Company gets to choose when to file rate cases. If it finds itself in a very profitable trading environment, it may retain the profits. If it accumulates or expects substantial trading losses, it may file a rate case. In either case, the Company may propose a test year that it finds to be the most advantageous. Consequently, to assure a proper balancing of ratepayer and shareholder interests, the Commission should insist that the costs built into rates do not reflect out of market trades.

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

A. If the Commission continues to use a fully projected test year, a better approach to address short-term firm transactions must be developed. To accomplish this end, I recommend the Commission convene a task force to develop a more accurate methodology for estimating a normalized level of short-term firm purchase and sales transactions.

In addition, I recommend the Commission require the prices of all short-term firm purchase and sales transactions be conformed to the March 31, 2004 forward price curve. In Confidential CCS Exhibit 6.2, I have repriced all above and below market short-term firm purchase and sales transactions, based on the March 31, 2004 forward price curve. This will provide a better representation of normalized net power costs and mitigate the inequity of PacifiCorp using only a small (and biased) sample of the actual short-term firm transactions. This adjustment reduces net power costs by the amount shown on line 3 of Table 1.

Q. DOES THE COMMITTEE HAVE AN ALTERNATE ADJUSTMENT RELATING TO THE SHORT-TERM FIRM TRANSACTIONS?

A. Yes. Committee witness Tony Yankel sponsors an alternative short-term firm adjustment.

Q. WHICH OF THE TWO SHORT-TERM FIRM ADJUSTMENTS IS REFLECTED IN THE NET POWER COSTS USED IN COMMITTEE WITNESS DERONNE'S SUMMARY EXHIBIT?

A. My recommended short-tem firm adjustment (shown on line 3 in table 1) is reflected in the net power costs used in Ms. DeRonne's summary exhibit.

<u>Long-Term Contract Modeling In GRID</u>

Q. DOES GRID MODEL LONG-TERM POWER CONTRACTS?

A. Yes. The Company includes the costs and energy produced by all of its long-term contracts in GRID along with its thermal generation resources in order to project normalized net power costs. For certain types of contracts, however, the Company typically does not (and for the most part cannot) reflect all the benefits of these transactions in GRID. These include the West Valley lease, certain kinds of contract options, hedges, and certain types of interruptible contracts. I will discuss these issues in the following sections of my testimony.

<u>West Valley Lease</u>

Q. BRIEFLY DESCRIBE THE WEST VALLEY LEASE.

A. The West Valley project consists of five 40 mW LM6000 CT units. The lease is a fifteen-year contract that obligates PacifiCorp to pay Pacific Power Marketing ("PPM"), a non-regulated affiliate, approximately $14.7 million per year to obtain the output from the West Valley CTs.

Q. IS WEST VALLEY A RELATIVELY HIGH COST RESOURCE FOR THE PACIFICORP SYSTEM?

A. Yes. The test year annual revenue requirement exceeds $100/kW year, excluding fuel.[6/] In addition to the lease payment, the Company is responsible for O&M expenses and property taxes on the facility. Based on the lease purchase option, the investment cost underlying the project is $765/kW. On a $/kW basis, the West Valley lease costs more than the Gadsby CTs or combined cycle plant additions such as the Currant Creek or Lakeside projects.

Q. PLEASE REVIEW THE CIRCUMSTANCES SURROUNDING THE COMPANY'S DECISION TO SIGN THE WEST VALLEY LEASE.

A. The West Valley lease provides a case study as to why such transactions demand a special level of attention. This lease is a long-term, high-cost transaction that PacifiCorp entered into with its affiliate, PPM. It was justified using questionable assumptions and entered into under questionable circumstances.

PPM began developing the West Valley Project as a "merchant plant" during the height of the Western power crisis in January 2001. At that time, there was a shortage of CT equipment in the West resulting in a very high cost for the turbines. However, the state of the market in early 2001 was such that even a very high cost project such as West Valley could have been quite profitable, so long as prices remained high. At the time, the FERC appeared reluctant to address the problems in the Western power market, suggesting prices would remain high indefinitely.

6/ According to the Company's response to CCS Data Request 8.2, total TY revenue requirements of $20,134,656 divided by 200 MW = $100.67/kW.

West Valley could have been a very attractive investment for PPM under those circumstances.

As project development progressed, however, the power crisis abated. Once the FERC set its price cap in June 2001, the high cost power from West Valley was much less attractive and PPM was caught with the West Valley project underway, but with limited prospects for finding buyers willing to purchase such expensive power. At some point during this period, PPM suspended construction of the Project until it could secure a buyer for West Valley's output. Construction was not underway when PacifiCorp issued a Request for Proposals ("RFP") in September 2001.

By the summer of 2001, PacifiCorp was convinced that it needed additional capacity to serve rapidly growing loads in its eastern control area. To address this problem it issued an RFP in September 2001 for resources capable of delivery by Summer 2002. West Valley was one of the resources selected in the RFP process. The lease was negotiated in early 2002, and finalized on March 5, 2002. The project became operational later that year.

Given PacifiCorp's pressing need for new capacity in Summer 2002, it was not possible in late 2001 to develop a larger and more economical project than West Valley. Thus, the short lead-time available for development of the project led to PacifiCorp's perceived need to sign the West Valley lease. These circumstances parallel those surrounding the Gadsby CTs, another relatively high cost 2002 capacity addition, necessitated by the pressing need for power at the time.

Q. HAS THE COMMISSION MADE ANY COMMENTS ON THE WEST VALLEY LEASE?

A. Yes. In the recent hearing in Docket No. 03-035-14, Chairman Campbell stated that the Commission was "extra interested" in transactions involving affiliated companies.[7]

Q. IN YOUR OPINION, WAS THE WEST VALLEY LEASE A PRUDENT RESOURCE ADDITION FOR PACIFICORP?

A. No. When one looks at the totality of the Company's participation in the project, particularly in light of the fact that it was a transaction with an affiliated Company, I have concluded it was imprudent. This is based on my analysis of the project starting from the initial decision to sign the West Valley lease, to the recent evaluation of the early termination option contained in the lease. Further, whether PacifiCorp's decision to enter into West Valley lease was prudent or not, certain costs associated with the lease are not reasonable ratemaking expenses, which should be disallowed.

Q. AS A PRELIMINARY MATTER, SHOULD PACIFICORP HAVE BEEN CAUGHT IN THE SUMMER OF 2001 FACING AN UNANTICIPATED AND PRESSING NEED FOR POWER THE VERY NEXT YEAR?

A. That is highly questionable. The Company has never really adequately addressed that issue. Normally, utilities strive through Integrated Resource Planning (IRP) to match resource needs with resource acquisition. Being caught "short" is quite uncommon in the industry, and raises questions of prudence, which the Company has an obligation to justify.

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[7] Reporters' Transcript of Proceedings, May 20, 2004, page 60

Q. HOW DID PACIFICORP EVALUATE ITS INITIAL DECISION TO ENTER INTO THE WEST VALLEY LEASE?

A. The Company evaluated its decision to sign the West Valley lease using the Black-Scholes methodology, which is also known as option theory.

Q. IS THIS AN ACCEPTED METHOD FOR VALUING ENERGY RESOURCES?

A. Black-Scholes modeling was originally applied to applications in securities trading for valuation of stock options. While the underlying assumptions of the method may be applicable for evaluation of financial instruments, there is no proof that they apply in the case of energy derivatives or physical energy resources. In my view, Black-Scholes modeling is a novel approach for resource selection for a regulated utility.

Q. HAS THE BLACK-SCHOLES METHODOLOGY BEEN WIDELY ACCEPTED FOR SECURITIES TRADING APPLICATIONS?

A. Yes. Based on my review of the literature, it is a commonly applied technique. However, it has not always been successfully applied. The Black-Scholes equations were used extensively by the infamous hedge fund, Long Term Capital Management ("LTCM"). LTCM was the fund directed by two Nobel Laureates, Myron Scholes and Robert Merton, that threw the financial world into near calamity. CCS Exhibit 6.3 is an excerpt from the transcript of a February 8, 2000 episode of Nova on the Public Broadcasting Service, which summarizes the LTCM debacle. The excerpt indicates that even with the help of two of the Nobel Laureates who are credited with developing the Black-Scholes equations, the dynamic hedging methodology used by LTCM failed to predict market movements, and nearly resulted in an epic collapse of the financial system.

Q. ARE YOU SAYING USE OF BLACK-SCHOLES MODELING FOR RESOURCE SELECTION DECISIONS IS IMPRUDENT?

A. I'll leave that for the Commission to decide. The Commission could consider disallowing the costs of resources selected by the model on the basis of imprudence. However, there is also a fundamental problem of equity in that the benefits ascribed to resources by the Black-Scholes modeling are impossible to reflect in a rate case test year. Thus, PacifiCorp is in the situation of having selected resources on the basis of certain speculative benefits that will never be reflected in a rate case setting. The Company ultimately justified its decision to enter into the West Valley lease not on the basis of its fundamental economic value, but rather on the basis of this novel methodology. This approach was quite different from the analytical methods the Company used (and the Commission accepted) in the certification of the Gadsby CT Units or the Currant Creek project.

Q. EXPLAIN YOUR COMMENT THAT THE WEST VALLEY LEASE IS NOT JUSTIFIED ON THE BASIS OF ITS FUNDAMENTAL ECONOMIC VALUE, BUT RATHER RESTS ON THE METHOD USED BY THE COMPANY TO EVALUATE IT.

A. This is demonstrated in CCS Exhibit 6.4C (Confidential) taken from the Company's response to DPU 12.1(a). This document is a copy of the economic evaluation of West Valley used by the Company to support the decision to enter into the lease.[8/] Analysis of this document demonstrates that the decision to sign the lease was imprudent.

8/ The Company previously contended that this analysis was the basis for its evaluation of the West Valley project in Oregon Docket No. UE-134. That case was ultimately settled as part of the global settlement in UE-147, PacifiCorp's 2003 general rate case in Oregon. Thus, the Oregon Commission has never directly decided the issue of prudence of the West Valley lease.

With reference to the rebuttal testimony of Mr. Mark Klein in UE-134 [DPU12.1(b)], CCS Exhibit 6.4C demonstrates the value of the lease option was $ per year over its fifteen-year term. Because this exceeds the $14.71 million cost of the lease, Mr. Klein contended that signing the lease was beneficial to customers and by implication prudent.

Q. BASED ON THE ANALYSIS SHOWN IN CCS EXHIBIT 6.4C, DO YOU AGREE WITH PACIFICORP'S CONCLUSIONS?

A. No. The claimed net benefit margin of about . At best, the analysis demonstrates for the project, but only if *all* of the underlying assumptions prove out.

However, I believe there are substantial problems with the analysis. First, the Black-Scholes method selected by the Company is responsible for the majority of the assumed benefits. Given that this method was not even applied in the contemporaneous Gadsby certification proceeding, this is quite disturbing.

Instead of applying a conventional power system simulation, PacifiCorp applied options theory (the Black-Scholes techniques) to estimate the value of the physical assets underlying the lease. However, the Company provides no foundation to establish that the assumptions underlying the model apply in the case of energy resources, particularly physical assets.

Second, the Black-Scholes method used by the Company did not provide a detailed *simulation* of the impact of the West Valley project on the PacifiCorp system, such as might be derived from a production cost model like GRID. Indeed, the methodology really does not even consider whether PacifiCorp actually needs the power, or might even ever dispatch it for purposes of serving native load. Rather, the unit is dispatched in response to general market prices. The limited dispatch modeling shown in CCS Exhibit 6.4C completely ignores factors that impact the PacifiCorp system dispatch such as minimum run rates, or transmission constraints. In fact, there is very little in CCS Exhibit 6.4C that would make it specifically applicable to PacifiCorp's system. It is little more than a generic analysis of the project based on expected market conditions. While this might be the norm for evaluating a merchant project for purposes of energy trading, it is not typical of the kinds of detailed analyses performed in the industry to evaluate the economics of a capacity addition to a utility system.

Q. HAS PACIFICORP PROVIDED ANY FOUNDATION SUPPORTING APPLICATION OF BLACK-SCHOLES TO THE EVALUATION OF A NEW RESOURCE?

A. No. PacifiCorp has not provided any foundation for the application of Black-Scholes modeling to evaluate a generation resource such as West Valley. There is no basis for assuming Black-Scholes – a tool applicable to securities trading – is an appropriate method for evaluating energy resources. For example, unlike financial instruments, there is no efficient trading market for energy resources. Evaluating the option to purchase or lease a CT resource is a much different exercise than evaluating a stock option.

While PacifiCorp prefers to describe West Valley as a "spark-spread" with various options attached, the Company could not evaluate some of the attributes of the project that were considered most significant in terms of options theory because there is no trading market for those products. For example, there is no efficient market for the quick start capabilities modeled in CCS Exhibit 6.4C. This undermines confidence in the application of Black-Scholes to this resource selection problem.

Q. CAN YOU DECOMPOSE THE CLAIMED $ IN ANNUAL BENEFITS FROM WEST VALLEY INTO DIFFERENT CATEGORIES?

A. Yes. The project can be thought of a producing the following benefits, based on PacifiCorp's analysis shown in CCS Exhibit 6.4C:

(a) 200 mW firm on-peak capacity and energy based on its expected market value, less operating costs ($);
(b) The "extrinsic" or "option value" of the lease associated with uncertainty related to future spark spreads ($) based on the Black-Scholes equation;
(c) Avoidance of the shoulder-sell off ($);
(d) Quick start capacity ($; and)
(e) Value of the early termination and project buy-out clauses ($).

These benefits add up to $ per year, or only $ million (about) more than the actual annual cost of the lease ($14.7 million.)

It should first be noticed that without any single one of the assumed benefits, the West Valley project is not economic. Moreover, a reduction of the quick start benefit ( ), ancillary services ( ) or the lease option value ( ) would eliminate any economic advantage of the project. If the "Black-Scholes" option value (item a.) above is overstated by just , then the project is uneconomic.

Of the claimed benefits, only (a) [capacity and energy], (c) [the shoulder sell-off value] and (d) [quick start capability] are based on what might be called the "fundamental value" of the resource such as one would expect to find in a traditional resource evaluation. Given that by

March 2002 PacifiCorp had already undertaken the certification of Gadsby CT Units, it is quite questionable whether PacifiCorp required the benefits provided by additional ancillary services.

Two of the most significant benefits ascribed to the West Valley project (the option value and the value of the purchase and early lease termination option) were estimated using Black-Scholes modeling. Without either one of the benefits, the project would be uneconomic.

In the contemporaneous Gadsby certification proceedings, the Company did not use Black-Scholes modeling. The same is true of the more recent Currant Creek and Lakeside certification proceedings. Thus, Black-Scholes modeling seems to have been an “ad-hoc” methodology applied only at the time when the Company was evaluating the West Valley lease.

An obvious question then is why did the Company use a much different approach in evaluating West Valley than it did in its decision to certify the Gadsby CT units and other recent projects. Given the [redacted]) for West Valley portrayed in CCS Exhibit 6.4C, and the close affiliate relationship with PPM, one might assume that the Company simply “shopped” for an evaluation method that would support the overall benefit of signing the lease.

Q. PLEASE ELABORATE ON THE BLACK-SCHOLES BENEFIT SHOWN ABOVE.

A. The second benefit [(b) the extrinsic or spark spread option value] derived by the Company reflects the benefits associated with application of the Black-Scholes equations and is related to the spread in the forward price curve; specifically, the chance that the "spark spread" could change over time. Thus, we should think of the West valley lease as having a "Black-Scholes spark spread benefit" of $. In other words, this is the amount of the project benefit that would disappear completely if we simply used PacifiCorp's forward price curve and long-term market price forecast to determine the value of the West Valley lease (as was done in the case of the Gadsby and Currant Creek projects.) This is the assumed value of the West Valley lease stemming from its ability to provide protection against unexpected increases in the spread between gas and electric prices. This type of benefit cannot be reflected in GRID, and was not considered in any of the recent certification cases.

Q. WERE THE ADDITIONAL BENEFITS CLAIMED BY THE COMPANY CRUCIAL TO THE ECONOMIC EVALUATION OF THE WEST VALLEY LEASE?

A. Yes. Assuming PacifiCorp's forward price curve analysis was perfectly sound, the annual capacity and energy benefits are only $ million compared to an annual expense of $14.7 million. Stated differently, the capacity and energy benefits were only of the annual lease payment. Had PacifiCorp stopped at this point, it should have never signed the West Valley lease in the first place. PacifiCorp *needed* to claim these additional benefits in order to show that the West Valley lease was economic. Without any one of the five claimed benefits, the project is clearly uneconomic on the basis of market fundamentals and PacifiCorp's own analysis as of the signing date of the lease.

Q. WERE ANY COSTS CONSIDERED IN THE GADSBY CERTIFICATION PROCEEDING THAT WERE IGNORED IN THE WEST VALLEY ANALYSIS?

A. Yes. In the Gadsby certification proceedings, the Company imputed additional reserve costs to Gadsby to cover forced outages. Such reserve costs were not included in the analysis of West Valley.

Q. WERE OTHER ASSUMPTIONS BIASED IN FAVOR OF WEST VALLEY IN CCS EXHIBIT 6.4C?

A. Yes. It was assumed the units would operate at their design (full load) heat rate (10,000 BTU/kWh) on an annual average basis. This would be impossible if the units were going to cycle and provide substantial operating reserves as assumed by the Company. Further, the PacifiCorp GRID modeling shows much higher heat rates for these units. Finally, the Company significantly understated staffing and O&M expenses associated with the facility in its cost estimates.

Q. EXPLAIN THE SIGNIFICANCE OF ALL THIS IN THE CONTEXT OF THE FACT THAT WEST VALLEY WAS LEASED FROM AN AFFILIATE, PPM?

A. The West Valley lease exemplifies why regulators have traditionally been extremely concerned about transactions between affiliates. Despite all protests to the contrary about prudence, the Company cannot change the fact that its lease from an affiliated Company is one of the highest cost resources on the system. Ironically, many QF project developers have recently argued for high-avoided cost rates based on the high costs of the West Valley lease.

In my view, good regulatory policy would require that an exceptionally high standard of proof be met when dealing with affiliate transactions. Indeed, the FERC has adopted a standard that requires a bidding process must be "*above suspicion*" when it results in award to an affiliate. For this reason alone, it would be wise to assign no value to highly speculative and subjective benefits, such as the options value. Further, all other costs and benefits should be conservatively estimated when considering the project.

Q. DID THE PURCHASE OPTIONS HAVE ANY VALUE IN 2002?

A. The purchase options were of very little value, even in 2002. The option purchase price is based on the original cost of West Valley ($765/kW) as depreciated in 2005 ($690/kW) and 2008 ($615/kW). This substantially exceeded the cost of a new, conventional, CT unit even in 2002. PacifiCorp's most recent IRP indicates that a new CT unit could be installed for approximately $500/kW. Further, the market for these CTs has declined sharply in the past few years, rendering the purchase option completely worthless at the present time.

Q. WAS THE EARLY TERMINATION OPTION OF THE LEASE OF ANY VALUE?

A. The option only had value because of the high cost of West Valley. If West Valley were an economical resource, an early termination option would have been without any significant value. However, given its high cost, had the Company made a good faith effort to take advantage of the early termination option, it could have provided value by undoing the original mistake. However, this value only exists to the extent the Company actually terminates the lease at the end of the third or sixth year and replaces it with a lower cost resource. Unfortunately, the Company never made a prudent effort to take advantage of the third year termination option.

Q. PLEASE EXPLAIN.

A. Section 12.1 (a) of the lease states as follows:

> a) The Lessee may terminate the Lease Term by giving the Lessor notice in writing of such termination on or before December 1, 2006; provided, however, that (i) if such notice is given on or before June 1, 2004 and not rescinded by notice in writing on or before September 30, 2004, this Lease shall terminate effective May 31, 2005; and (ii) if such notice is given after June 1, 2004 and not rescinded by notice in writing on or before June 30, 2007, this Lease shall terminate effective May 31, 2008;

The plain language of this section of the contract provided PacifiCorp an opportunity to escape from the lease in June 2005, by giving notice prior to June 1, 2004. Because the original lease was evaluated and negotiated in the aftermath of the Western power crisis, and at a time when CT capacity was very scarce, a prudent utility would have taken a very serious look at terminating the lease and replacing it with a lower cost resource.

Q. HOW WOULD A PRUDENT UTILITY HAVE RESPONDED TO THIS EARLY TERMINATION OPTION?

A. The early termination option would have been useful as a tool to obtain lower prices from other suppliers, or as negotiating leverage with PPM. To take full advantage of the option, PacifiCorp should have given its notice well in advance of June 1, 2004 and evaluated the most economical options available at an earlier time. Since this was a long-term resource, it would have been sensible to consider an RFP timed to provide replacement capacity starting on June 1, 2005.

Q. DID PACIFICORP HAVE AN OPPORTUNITY TO ISSUE SUCH AN RFP?

A. Absolutely. PacifiCorp issued RFP 2003-A on June 6, 2003. This RFP was issued in ample time to have provided a permanent replacement for West

Valley by June 1, 2005. RFP 2003-A even requested 200 mW of east side peaking capacity, an amount identical to the capacity of West Valley. The Company could have easily requested 400 mW of east side peaking capacity for the summer of 2005. There was simply no reason why PacifiCorp could not have used the RFP 2003-A process to seek out the most economical replacement available for West Valley. However, the Company never even considered replacement of West Valley in conjunction with RFP 2003-A.

Q. WHEN DID PACIFICORP GIVE ITS TERMINATION NOTICE ON THE WEST VALLEY LEASE?

A. The Company gave its termination notice in late May 2004. This termination notice was provided only *after* inquiries were made on the issue by the CCS and DPU, as well as ratepayer representatives in Oregon and the Oregon PUC staff. CCS Exhibit 6.5 is a copy of certain letters discussing this issue. My interpretation of these events is that the Company simply “dragged its feet” on the matter until pressure from regulators and customer representatives forced the issue. Again, this is clear evidence of a utility more interested in supporting its affiliate than minimizing costs for its ratepayers.

Q. IS IT REASONABLE TO ASSUME THE COMPANY COULD HAVE OBTAINED A LOWER COST REPLACEMENT FOR WEST VALLEY HAD IT SOUGHT A REPLACEMENT IN RFP 2003-A?

A. Yes. In Docket No. 03-035-29 (Currant Creek), the Company’s bid evaluation model demonstrated that traditional peaking units were much less economic than combined cycle generators. Further, given the high cost of West Valley relative to more conventional types of CTs, it is quite likely West Valley would have been a very unattractive option for the Company. Finally,

(Confidential)

(Docket No. 03-035-29, Data Response CCS4.21 Confidential) One can easily infer that a West Valley "Next Best Alternative" would have never made the short list had it been examined in RFP 2003-A. Clearly the Company failed to avail itself of the best opportunity to obtain resources at a much lower cost than West Valley.

Q. DID THE UTAH COMMISSION ALSO MAKE INQUIRIES REGARDING THE EARLY TERMINATION OF THE WEST VALLEY LEASE?

A. Yes. In the hearing in Docket No. 03-035-14 on May 20, 2004 the Commission inquired as to the status of the West Valley lease:

> CHAIRMAN CAMPBELL: Let me ask about – I guess some of that was based on testimony related to West Valley, whether that was in or out or a deferrable resource contract. I guess I'd like to ask the Company, and it's my understanding that you had a major party in Oregon ask you to give notice on June 1st related to that contract. Can you just based on the testimony of that now is on the record related to West Valley, would you please let us know what you intend to do if you've made a decision?
>
> MR. TALLMAN: Well, like most decisions we're -- we're looking at it pretty closely*. **One of the things that we're looking at that we're very concerned about is that we make sure we fully understand the option language that's in the agreement as far as how we understand it versus how our counter party understands it. And one of the things -- so we're having a legal analysis done on that right now***. The obvious concern with that is if we don't see it eye to eye, that if we were to go ahead and exercise an option and then change our mind and that somehow affected our ability with the next option period, which, of course, is a longer term decision, but the decision now is a three-year decision, it basically affects the 2005 through 2008 timeframe, which is really the summers of 2005, six, and seven. And those review the '05, '06 summers as being pretty important, at least I do, in terms of resource needs. So I'm very -- I want to be very cautious, judicious,

> prudent before we make the election to issue a termination notice even if we think we might have to unwind that termination notice. So that's where we are at right now. And certainly before June 4th or June 1st we'll get that sorted out.
>
> * * *
>
> CHAIRMAN CAMPBELL: I'm trying to be as subtle as I can to send signals that the Commission is interested in that contract in that the past rate case things were stipulated. And so this is the first case before this Commission we've fully seen numbers and discussion related to that contract. Clearly, we're concerned, but we are interested and ***extra interested in contracts related with affiliates*. *And so maybe my expectation of the Division would audit this and other parties would take a serious look at this as far as any future rate case*.** (Reporters' Transcript of Proceedings, May 20, 2004, pages 55-60, emphasis added)

PLEASE COMMENT ON MR. TALLMAN'S ANSWER TO THE COMMISSION.

A. His answer seems rather strange in light of PacifiCorp's prior testimony in Oregon Docket No. UE-134 (2002) and Washington Docket No. UE-032065 (2003):

> **Q. Does the lease give PacifiCorp an option to purchase the Project or terminate the lease?**
>
> A. Yes. PacifiCorp has two options (vesting in years three and six) to either terminate the lease or purchase the Project. If PacifiCorp elects to exercise either purchase option, the fixed purchase prices ($138 million and $123 million, respectively) are estimated to be near the then-depreciated book cost for the Project at the time of the purchase. These options allow PacifiCorp to hedge against changes in market prices and load forecasts in the coming years and then decide which of three paths—continuation of the lease, termination of the lease or outright purchase of the Project—is the best economic choice. (Attachment to DPU12.1, Supplemental Direct Testimony of Mark Tallman Oregon Docket No. UE-134.)
>
> *** * ***
>
> **Q. What specific risks are mitigated through the additional options in the lease structure?**
>
> A. There is higher uncertainty over the value of the spark spread associated with a longer time horizon, therefore, it is prudent and valuable for PacifiCorp to make provisions to cut losses if the spark

spread collapsed and to capture additional value if the spread widened. The lease termination and the plant purchase provisions in year 3 and year 6 of the lease serve this risk mitigating purpose.

Q. How were the values for termination of the lease and plant purchase determined?

A. Option theory was used to value the special contract provisions. The option to abandon the lease was valued as a put option with the strike equal to the NPV of the remaining lease payments against the underlying asset price (i.e., NPV of free cash flows for the remaining lease period).

The option to purchase the plant is a call option with the strike at the net book value against the underlying asset price (i.e., NPV of free cash flows until the end of the thirty-year assumed book life plus the liquidation of remaining assets). To value this option, the Company explicitly calculated the residual value of the plant based on the best market information available. The cumulative value of the put and call options in year 3 of the lease is in excess of $28,568,000. The value of this premium is included in the annual lease payment; it is not paid up-front, but instead spread across the whole duration of the lease as an annuity discounted at 2.5 percent. Therefore, if PacifiCorp exercises the lease termination option, PPM will not receive full payment for the options it granted. The annualized contract option premium is $2,110,000. (Attachment to DPU12.1, Supplemental Direct Testimony of Mark Klein Oregon Docket No. UE-134.)

*** * ***

Q. Does the lease give PacifiCorp an option to purchase the West Valley Project or terminate the lease?

A. ***Yes, the lease is very flexible. PacifiCorp has two options (vesting in years three and six) to either terminate the lease or purchase the West Valley Project.*** If PacifiCorp elects to exercise either purchase option, the fixed purchase price ($138 million or $123 million, respectively) were, at the time, estimated to be near the then-depreciated book cost for the West Valley Project at the time of the purchase. These options allow PacifiCorp to hedge against changes in market prices and load forecasts in the coming years and then decide which of three paths-continuation of the lease, termination of the lease or outright purchase of the West Valley Project-is the best economic choice. (Direct Testimony of Mark Tallman, Washington Docket No. UE-032065, Page 7 December 2003, emphasis added)

These passages show the Company was very quick to point out the lease termination options to the Oregon and Washington Commissions, and even ascribed a substantial dollar value to those options. However, when it came time to actually exercise the option, the Company determined that it suddenly needed a “legal analysis” of the lease to verify these same terms and conditions.

Q. IS THIS EVIDENCE OF IMPRUDENCE?

A. Certainly. The Company should have performed a detailed legal analysis of the lease when it was being negotiated, not two years later. They should not have required any further legal analysis in order to confirm what the lease itself plainly states in Section 12.1 and what the Company told the Oregon and Washington Commissions in 2002 and 2003. It appears the Company simply used the need for a legal analysis as an excuse for failing to conduct a fair evaluation of the lease through a reasonable RFP process much earlier. In any case, were a legal analysis needed at all, there is simply no prudent reason why it could not have been performed long before May of 2004.

Q. WAS RFP 2004-X A REASONABLE AND PRUDENT EFFORT TO FIND A LOWER COST REPLACEMENT FOR WEST VALLEY?

A. No. The Company biased its selection process in favor of West Valley by soliciting only bids for resources that had similar contract terms and options as West Valley:

> This solicitation seeks resources that may replace the leased resource, as more fully described below, with a resource capable of delivering electricity to PacifiCorp's network transmission system at a location that can, utilizing firm transmission rights, deliver the electricity to a point electrically North of Camp Williams and South of Ben Lomond substations. The replacement resource must be available as of June I , 2005 for terms of: a) three (3) years, or b) three (3) years with a nine (9) year extension option to be exercised at PacifiCorp's option prior to June 30, 2007, or 3) up to twelve (12) years with a three (3) year minimum. (RFP 2004-X, issued July 19, 2004, page 3).

By issuing the RFP so late (less than 11 months prior to the date power was needed, and insisting on a minimum three-year term), the Company virtually eliminated any realistic option for the construction of new capacity.

Q. WAS THIS REASONABLE?

A. No. In effect, the Company assigned an infinite value to the early termination option, as it refused to consider options other than those with a minimum three-year term. This is strange considering that when the Company first evaluated the lease it believed it had a methodology that could fairly monetize the value of the early termination option. If PacifiCorp still believed in Black-Scholes modeling, it would have ascribed some fraction of the previously determined lease option value to West Valley because there was only one remaining termination option. I also find this quite ironic given that the Company argued in the Currant Creek proceedings that differences in the contract terms and lives of resource options can be reasonably addressed through the use of real levelization.

Q. DO YOU DISPUTE THAT THERE IS SOME VALUE IN HAVING AN EARLY TERMINATION OPTION?

A. In theory there is, but only due to the high cost of West Valley. However, PacifiCorp clearly needs long-term resources. There is little reason to expect that it will suddenly become long on capacity and avoid the need for 200 mW of capacity in 2008. Further, for the option to have any real value, it must be evaluated in a manner that is timely, reasonable and prudent. PacifiCorp failed on all three counts. Given that this is a lease with an affiliated Company, there is ample reason to be suspicious of the entire arrangement. Were this case being heard by the FERC, I fail to see how it would survive the FERC's "*above suspicion*" standard.

Q. REGARDING THE ACTUAL BID EVALUATION IN RFP 2004-X, DO YOU BELIEVE THAT PACIFICORP'S ANALYSIS IS SOUND?

A. I am very skeptical of PacifiCorp's bid evaluation. The Company has refused to make its bid evaluation available for review outside of its corporate offices, owing to its designation as "Highly Sensitive." Considering this material is no different from that provided directly to parties in the Currant Creek proceeding, I believe this was nothing less than an effort to minimize the opportunity for parties to review and challenge the assumptions and methods used in the bid evaluation.

I did have an opportunity to review the workpapers underlying the RFP 2004-X bid evaluation on November 10, 2004. While my review was limited in scope, it was apparent that a substantial portion of the advantage assumed for West Valley was due to modeling of its ancillary service benefits (principally spinning reserve and quick start). My discussions with personnel from the PacifiCorp dispatch center (on the same day) and review of West Valley's generator logs calls this assumption into question. Owing to the presence of substantial resources on PacifiCorp's system that are able to provide quick start and operating reserves, West Valley is seldom needed for purposes of carrying reserves. This is substantiated by the Company's response to DPU9.7a, which demonstrates that on average, West Valley has only had 10 mW of capacity available for spinning reserve per month in 2004.

Further I have learned that any quick start benefits of West Valley are limited to the capacity of one unit.[9/]

Q. HOW DID PACIFICORP DETERMINE THE ANCILLARY SERVICES BENEFITS OF WEST VALLEY?

A. I understand this was based on a GRID run where the ancillary services characteristics of West Valley were “turned off”. However, there are many issues surrounding the modeling of CTs in GRID. For example, I demonstrate later in my testimony that the model is operating the CTs in a very unrealistic manner, owing to inaccurate assumptions concerning operating reserve and regulation modeling. Thus, these ancillary services benefits derived from GRID runs are highly questionable.

Q. HOW DO YOU PROPOSE TO DEAL WITH THE ISSUES SURROUNDING THE EARLY TERMINATION OPTION?

A. Irrespective of the prudence or imprudence of the original West Valley lease decision, the Company failed to avail itself of a reasonable opportunity to obtain the best alternatives to replace West Valley in 2005. Instead, the Company made a late “half-hearted” effort primarily due to the prodding of regulators and consumers groups.

Consequently, I recommend the Commission adopt a disallowance based on the cost of replacing West Valley in RFP 2003-A. Based on (Confidential) a replacement unit would have cost no more than $(Confidential). This is a conservative estimate of the level of this disallowance because the proxy bid was not even on the short list in RFP 2003-A. This results in a

[9] The current staffing at the West Valley control room is limited so that only one unit can be started in ten minutes. This was pointed out by PacifiCorp dispatch center personnel on November 10, 2004.

reduction to the West Valley lease in the amount shown on line 1 of Table 1.

Q. DO YOU HAVE AN ALTERNATIVE WEST VALLEY ADJUSTMENT FOR THE COMMISSION TO CONSIDER?

A. Putting aside the rather serious prudence questions surrounding the original decision to sign the West Valley lease and the evaluation of the early termination option, the Company's proposed treatment of the resource is asymmetric. PacifiCorp includes 100% of the West Valley lease in rates, but does not reflect any of the Black-Scholes benefits that led the Company to select the West Valley lease in the first place.

As I previously discussed, the options theory modeling was the *primary* driver behind the decision to sign the West Valley lease. Based on the figures presented in PacifiCorp's bid evaluation model, without the assumed option value, the West Valley lease was not an economic choice for the Company. In fact, the option value pushed the West Valley lease "over the top" in PacifiCorp's evaluation.

These benefits were derived in PacifiCorp's bid evaluation model by quantifying the value of mitigating unexpected variations in the spark spread. While the Black-Scholes methodology facilitates such an analysis, it does not exist in GRID. GRID uses a "point estimate" for its forward price curve. Thus, there is no way the option value benefit of West Valley can be reflected in GRID. Therefore, even if the Commission were to decide the initial decision to sign the West Valley lease was prudent, the Black-Scholes (or spark spread option) value of West Valley is not a reasonable ratemaking expense and should be disallowed.

The same is true of the early termination option value assumed in the original evaluation models. This value, also based on Black-Scholes modeling, was never realized because of the lack of a prudent and timely lease termination evaluation. It cannot be reflected in test-year revenue requirements in any meaningful way. As in the case of the spark spread options value, this benefit by itself was necessary to show an economic advantage to the project.

As an alternative to an outright imprudence disallowance, the Commission should disallow an amount of the West Valley lease payment equal to the spark spread option value and early termination option value included in CCS Exhibit 6.4C. The total amount of the alternative West Valley disallowance is $5.015 million in the test year.

P4 Production Company Contract

Q. DESCRIBE THE P4 CONTRACT.

A. The P4 contract has three components: System Integrity, Operating Reserve and Economic Curtailment. The System Integrity ("SI") clause allows the Company to interrupt 62 megawatts ("MW") for only twelve hours per year. GRID models the operational impacts of the first two elements of the contract, but not the capacity from the SI clause. PacifiCorp valued the SI clause at the (then effective) Federal Energy Regulatory Commission's ("FERC") price cap value of $250/mWh. This resulted in a cost of $40,500 per month, or $486,000 per year. The Company ignores the SI capacity in GRID, because it assumes that under normalized conditions a qualifying event would never occur.[10/] In GRID, the contract is modeled as a "no-energy archetype."[11/] This is a situation where use of a point estimate for hourly market prices (and failure to model outages in a probabilistic manner) fails to capture all of the benefits the Company believes will exist in actual operation.

Q. WHO WOULD BENEFIT IF A QUALIFYING EVENT WERE TO OCCUR, PACIFICORP OR ITS CUSTOMERS?

A. The Company would avoid the necessity of purchasing what might be very costly replacement power. The Company clearly benefits from this contract. However, it expects customers to bear the full cost of this "insurance policy."

Q. HOW DO YOU RECOMMEND THE P4 TRANSACTION BE MODELED?

A. To achieve proper matching of costs and benefits, I impute additional power cost savings in the amount necessary to equalize the costs and benefits of this transaction. This adjustment reduces net power costs by the amount shown on line 4 of Table 1.

<u>Aquila Hydro Hedge</u>

Q. ARE THERE OTHER TRANSACTION BENEFITS THAT ARE NOT REFLECTED IN GRID?

A. Yes. PacifiCorp includes the cost associated with the Aquila hydro hedge. This contract is also modeled as "no-energy archetype." The primary benefit of this transaction is to reduce financial risk for PacifiCorp. However, there is no reflection of the hedge benefits in GRID. It is not proper to reflect only the costs of hedges in setting normalized rates.

10/ PacifiCorp's response to CCS DR 8.5b.

Under "normalized conditions" hedges are not really a necessary ratemaking cost because only "normal" conditions apply.

For the hydro hedge, the Company makes payments to Aquila when actual hydro energy exceeds a certain level. In the case of poor water conditions, the Company receives a payment from Aquila. The Company pays Aquila $1.75 million per year, as the fixed cost of the hedge. Only this cost is included in GRID, with no reflection of the payments from Aquila.

Q. WOULD IT BE POSSIBLE TO MODEL THIS TRANSACTION IN GRID?

A. With some modifications it might be possible because GRID already simulates 19 different water availability scenarios. This logic could probably be modified to reflect the payments and credits under the contract. However, I do not recommend attempting to model this transaction in GRID because the contract was never expected by PacifiCorp to produce a positive net present value. In fact, as structured, the contract was originally expected to result in PacifiCorp making payments in excess of receipts of $10 million[12/] over the five-year term of the deal, based on the Company's Monte Carlo simulation of the contract.

Q. WOULD DISALLOWING HEDGE COSTS DISCOURAGE PACIFICORP FROM UNDERTAKING PRUDENT RISK MANAGEMENT?

A. I believe that is unlikely. CCS Exhibit 6.6C (Confidential) is a copy of a PacifiCorp presentation regarding evaluation of the hydro hedge. This evaluation did not address cost recovery, but instead measured the earnings impact of the hedge. The primary benefit of the hedge shown in

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11/ Which is just a clever way of saying it does nothing.

12/ On an expected value basis.

the analysis was to reduce the volatility in PacifiCorp's earnings. Based on this analysis it certainly appears that PacifiCorp undertook the hedge without any consideration of passing the contract costs and benefits through to ratepayers. Had the Company done so, there would be no earnings impact resulting from the hedge. For this reason, I believe it is safe to assume that the Company would undertake such hedging strategies independent of rate treatment considerations. Ironically, if all costs and benefits of hedges were passed through to ratepayers, there would be no beneficial reduction in earnings volatility for the Company.

The primary benefit of this contract is not that it reduces *costs* for PacifiCorp, but rather that it reduces PacifiCorp's *risk* (i.e., exposure to higher than expected power costs when poor hydro conditions exist). However, there is no way in which the benefit of reduced risk can be monetized and factored into the ordinary ratemaking process. As modeled in GRID, the Aquila hydro hedge is just a "one-way street" where ratepayers pay the costs, while PacifiCorp stands to reap the benefits.

Q. COMMISSIONS TYPICALLY ALLOW INSURANCE PREMIUMS AS AN ORDINARY RATEMAKING EXPENSE. ISN'T THIS JUST LIKE AN INSURANCE POLICY?

A. No, there are some important differences. First, PacifiCorp not only pays a premium, it also makes payments to Aquila when hydro conditions are good. This would be like paying extra for storm damage insurance when less than the normally expected amount of storm damage occurred.[13/]

Second, in the case of other kinds of insurance (for example property insurance) the benefits flow through to ratepayers in a variety of ways. For example, I understand that in the case of the Hunter Unit 1 outage, much of the repair cost was covered by insurance and, therefore, was not borne by ratepayers. While ratepayers may pay the cost of ordinary insurance, they also receive benefits that actually occur. In the case of the hydro hedge, there is no way in which ratepayers can obtain the benefits in the current GRID model, *and* the contract also produces expected costs in excess of the expected benefits.

Finally, hedging is a higher risk endeavor than purchasing an insurance policy. Under the hydro hedge, for example, the Company could end up making very high payments to Aquila, with no revenues in return. Further, these kinds of hedges are a new product without a long history behind them. This makes it difficult for the Commission to answer such questions as to whether the amount of the premium is reasonable compared to the benefits. For example, there is no evidence to demonstrate that the premium of $1.75 million is a reasonable price.

Q. DO YOU AGREE WITH PACIFICORP'S PROPOSAL TO USE A BALANCING ACCOUNT TO DEAL WITH THE HYDRO HEDGE PAYMENTS OR RECEIPTS?

A. No. Mr. Widmer recommends a balancing account to pass through the hydro hedge costs and revenues. This proposal is an unnecessary complication in the ratemaking process and given the uneconomic nature of the Aquila hedge would likely result in a loss for ratepayers. Because the payments under the hydro hedge could be substantial, implementing this type of balancing account seems unwise. The Company has made similar balancing account proposals in prior cases in Utah, Washington

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13/ This would seem like a very perverse form of a "good driver discount" if applied to car insurance.

and Wyoming. So far, no state has approved recovery of the hydro hedge premium or implemented a balancing account of any kind. When faced with the hydro hedge issue, the Wyoming Commission simply rejected recovery of the hedge premiums in their 2003 rate case.[14/] Likewise, in the most recent Washington case, the Company stipulated not to seek recovery of the Aquila hedge and cancelled a proposed temporary rider. While the most recent Oregon and Utah cases were settled in a manner that does not fully reveal the outcome of this issue, the topic was certainly an item discussed during the proceedings *and no temporary rider or balancing account was applied in either state.*

Fort James Cogeneration Project

Q. DO YOU AGREE WITH PACIFICORP'S MODELING OF THE FORT JAMES COGENERATION PROJECT?

A. No. The Company has overstated the generation purchased from this project compared to recent actual data. It is apparent the output from this project has declined for the past three years. Because this reduction appears to be continuing, I recommend use of an actual data from the 2004 Fiscal Year to estimate generation from the project.[15/] Thus, PacifiCorp has overstated net power costs by the amount shown on line 6 of Table 1.

Kennecott Reimbursement

Q. DOES GRID REFLECT THE BEST ESTIMATE OF THE KENNECOTT REIMBURSEMENT?

A. No. Based on the Company's response to CCS8.29, it is overstated by the amount shown on line 7 of Table 1.

14/ Re PacifiCorp, Wyoming Public Service Commission ("PSC"), Docket No. 20000-ER-03-198 (Feb. 28, 2004).

15 More recent actual data through September 2004 shows a continuing decline in generation from this plant.

Thermal Dispatch Adjustments

Q. DO YOU HAVE ANY CONCERNS REGARDING MODELING OF THERMAL DISPATCH IN GRID?

A. Yes. I am concerned that the simulated operation of gas-fired CT units in GRID is unrealistic. In reviewing the GRID hourly dispatch, I found that once dispatched, gas-fired CT units run almost exclusively at minimum loading levels. This operation of CT units is not representative of actual system operation, however.

CCS Exhibit RJF6.7 is a graph comparing the most recent actual and GRID (simulated) capacity duration curves for West Valley CT Unit No. 1. This unit is typical of PacifiCorp's CTs. Based on this analysis, once dispatched the CT unit normally operates at or near full loading. However, in GRID the unit runs almost exclusively at its minimum loading (20 mW). This unrealistic operation (in GRID) causes the Company to lose opportunities to make sales from CT units during periods with high market prices, and also results in higher than actual heat rates in GRID.

Q. WHAT IS THE CAUSE OF THIS PROBLEM?

A. There may be more than one cause. However, it appears a very important contributing factor is the reserve and regulation modeling in GRID. Based on discussions with operators from PacifiCorp's dispatch center at a November 10, 2004 technical conference that I requested, Gadsby and West Valley are not typically needed to supply operating reserves. It appears that one of the major reasons for this is that PacifiCorp ordinarily uses 100 MW of its Fixed Transmission Rights (FTR) between the PACW (west) and PACE (east) control areas for capacity purposes (including provision of operating reserves) rather than for energy purposes. This technique effectively increases the amount of operating reserves supplied by PACW to PACE (also called dynamic overlay) from 100 MW to 200 MW. This operational practice appears to subsequently reduce system costs.

In addition, it appears that the Company has overstated the regulation requirements on the system. While GRID models a maximum regulation requirement of 125 MW in PACE, in practice the requirement in PACE is limited to 50 MW. Further, GRID models a minimum regulation requirement of 50 MW. Based on my reading of NERC and WSCC standards, the minimum can be zero mW if load is declining.

Q HOW HAVE YOU ADDRESSED THIS PROBLEM?

A. I have reduced the FTR for the Idaho to East Main link in GRID by 100 MW, increased the dynamic overlay capacity to 200 MW, and adjusted the regulation requirements as well. I also limited the quick start capability at the Gadsby and West Valley CTs to one unit at each station for the reasons discussed earlier. This approach better approximates actual operations, and provides more realistic modeling of CT units as is shown in CCS Exhibit 6.8. This exhibit compares the mean, maximum and standard deviations of hourly loading of CTs in GRID to actual operations. Under PacifiCorp's assumptions, in GRID CTs almost never run above minimum loading in stark contrast to actual operations. My modeling changes result in a CT dispatch where average hourly loading, and the standard deviation in hourly loading, is much closer to actual statistics for FY 2004. This means that the distribution of loading across the daily "duty cycle" better matches actual operations. Implementing this change reduces net power costs by the amount shown on line 11 of Table No. 1.

VISTA Hydro Modeling

Q. ARE YOU FAMILIAR WITH THE VISTA HYDRO MODELING TECHNIQUES?

A. Yes. I participated in two workshops related to the VISTA modeling conducted by the Company in Oregon.

Q. HOW DOES VISTA DIFFER FROM THE HISTORICAL 50 WATER YEAR MODELING APPROACH?

A. VISTA does not use traditional water year modeling; it uses 19 excedence levels ranging from the 5th percentile to the 95th percentile. This data develops nineteen hydro generation scenarios for each resource based on historical stream flow data. Mr. Widmer's testimony describes this data in more detail.

Q. WHY IS IT NECESSARY FOR PACIFICORP TO CHANGE HYDRO MODELING TECHNIQUES AT THIS TIME?

A. Mr. Widmer testifies that the hydro data available from BPA is "becoming stale."[16] During the VISTA workshops the Company also indicated that the BPA was no longer sharing supporting information. Consequently, the Company can no longer document the fifty water years of data it traditionally used in its power cost modeling.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE VISTA MODELING?

A. Yes. There are two serious (and related) problems with the VISTA data. The first problem is that the data used by VISTA were not available for all

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16 Widmer direct testimony, page 16.

of the hydro resources for the same years or from the same sources. Mr. Widmer testifies as follows:

> For the Lewis and Klamath Rivers, the stream flows used as inputs to the VISTA model are the flows that have been recorded by the Company at each of the projects. In most cases the flows, using a very simple continuity of water equation where Inflow = Outflow + Change in Storage, are used to develop generation levels.
>
> For the Umpqua River, the inflow data was reconstructed by piecing together a variety of historical data sources. The USGS gauge data at Copeland (the outflow of the entire project) was used to true up the previously recorded flows developed using the continuity equation described above.
>
> The Company's Mid-Columbia energy is determined by using VISTA to optimize the operations of the of the six hydro electric facilities below Chief Joseph under 60 years of "modified" stream-flow conditions
>
> * * *
>
> The period of historical data varies by plant. As noted above, the Mid-Columbia projects are adjusted to water year 1928/29. The Company's large plant data begins in the 1958-1963 range. The Company's small plant data begins in the 1978-1989 range. (Widmer Direct Testimony, pages 18-19.)

It is apparent that there is no consistency in the data sources used for the various plants. While this may not necessarily be a serious problem by itself, it does reduce my confidence in the VISTA modeling. However, a more serious problem is the manner in which the Company used these disparate data sources to create the 19 scenarios used in GRID.

Q. PLEASE EXPLAIN.

A. PacifiCorp's hydro resources are located on several different river systems: the Columbia, Lewis, Klamath and Umpqua Rivers in the West and the Bear River in the East. While stream flows on a given river are such that there is a very high (though still imperfect) correlation between the output of generators on the same river for a single month or year, this is not the case for different river systems. Because the Company lacks a consistent set of data for all of its river systems, it is not possible (based on the VISTA data) to make a determination of the correlation between the level of generation of resources on different rivers. Therefore, the Company had to make an assumption as to the correlation between the flows on the different rivers. The Company assumed that generation from all of its hydro resources was perfectly correlated. This means that all of the hydro resources are assumed to experience their best and worst conditions simultaneously.

For example, the Company assumed that if the Western system hydro resources were having a 5% year, the same would be true for the Mid-Columbia and even the Eastern hydro resources. Thus, the VISTA 5% case assumes that all three major resource systems will experience a “one in twenty year” drought. The 10% case assumes a “one in ten year” drought for all three resource systems and so on.

Because the Company lacked a consistent set of data, it assumed perfect correlation of the data and created a set of 19 “equally likely” hydro scenarios for use in GRID, which it relates to the 5%, 10%, 15% percentiles, and so on.

Q. IS THIS A REALISTIC ASSUMPTION?

A, No. CCS Exhibit 6.9 shows a graph of the BPA 50 water year data for the Mid-Columbia system and other PacifiCorp river systems. The data show there is almost no correlation between generation from these resources over the period 1929-1978. Indeed, the correlation coefficient, *p*, between the two data series is only .2, implying only a very weak correlation. While this is a somewhat surprising result, it is supported by the 50-year BPA data used exclusively by the Company for many years.

For the Eastern (Utah Power and Light) hydro resources, there are no data to establish a correlation one way or the other. However, it stands to reason that given the large geographic distances between these river systems, any correlation that existed would be coincidental.

Q. COULD YOU PROVIDE A SIMPLE ANALOGY TO ILLUSTRATE THIS?

A. Consider a simple game involving six throws of a pair of dice. Assuming the dice are fair, one can easily compute the expected value outcome of a throw, by assuming each side of a single die would have chance of one in six of occurring. Thus, one could compute an excedence level of 16.66% for a score of one on a single die; 33.33% for a score of two; 50% for 3; 66.66% for four; 83.33% for five; and 100% for six.

In the VISTA method, for a roll of a pair of dice, the Company assumes that the two die (like two river systems) are perfectly correlated. This would mean an excedence level of 16.66% to roll a pair of ones; 33.33% for a pair of twos; 50% for a pair of threes and so on. It should be fairly obvious that excedence levels computed under the VISTA assumption are completely unrealistic. Indeed, simple probability theory shows that the chances of rolling a pair of any number is (1/6)*(1/6) or 1/36. If the river systems, like individual die are independent, the VISTA methodology systematically miscalculates the excedence levels, even if we assume the underlying data are perfectly accurate.

Q. IN A HYPOTHETICAL GAME INVOLVING THE ROLL OF A PAIR OF DICE, WOULD THE VISTA ASSUMPTION PRODUCE AN ACCURATE RESULT?

A. In general, no. Certainly in some "games" it might produce an acceptable approximation, but only in specific instances. For example, in a game where the sum of the two scores is added for six rolls of the dice, the VISTA assumption would produce a result with the same expected value as a proper analysis. Based on my analysis, the VISTA assumption appears to produce the correct expected value of hydro generation for this reason.

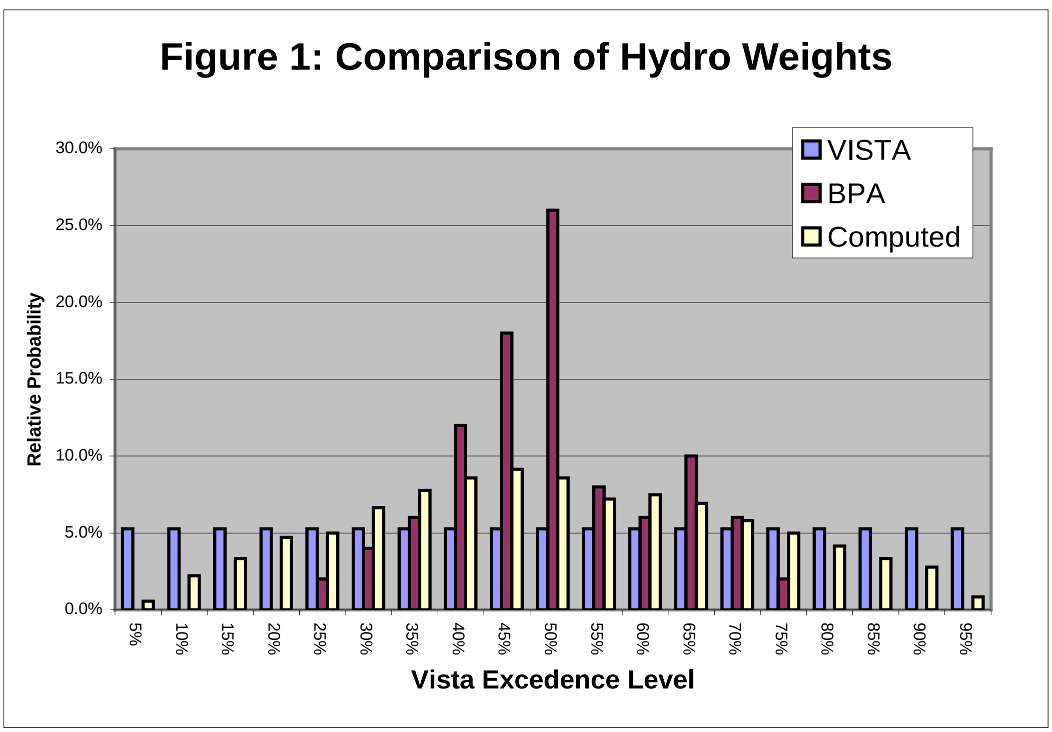
However, in a game where one computes the product of the outcomes for six rolls of the dice, the VISTA assumption will seriously overstate the expected value of the total score. CCS Exhibit 6.10 shows examples illustrating this point. Consequently, the VISTA assumption may produce accurate results for some variables, but not for net power costs as I will show later.

Q. WHAT IS THE FUNDAMENTAL PROBLEM WITH THE VISTA MODEL?

A. The most substantial problem is that VISTA overstates the likelihood of extreme events, whether they be drought or flood conditions. Returning to the dice example, the probability of a pair of ones (or a pair of sixes) is only 1 in 36. In VISTA it is assumed the probability is 1 in 6. However, VISTA ignores the many more likely scenarios where the two die have different face values (e.g. a one and a six.)

Q. IS THERE ANY EMPIRICAL EVIDENCE THAT DEMONSTRATES VISTA OVERESTIMATES THE LIKELIHOOD OF EXTREME CASES?

A. Yes. I have compared the 50-water year BPA data (with Mid-Columbia adjusted to current levels) with the VISTA data. The chart below shows that on an annual basis the extreme water conditions modeled in VISTA have never occurred in actual history. Further, the VISTA distribution is flat, while the actual distribution is closer to a “bell shaped curve” (though it probably is skewed). It shows that while VISTA would suggest the most extreme cases should be given a weight of about 5%, the BPA data suggest that those cases should be given a weight of zero. A more exact approximation (to be discussed shortly) indicates the proper weight should be less than 1%. Supporting data are shown on CCS Exhibit 6.11.



Q. IS THERE AN EXACT SOLUTION TO THIS PROBLEM?

A. It is not possible to completely correct this problem given the lack of data for overlapping years in VISTA for the various river systems.

To address this problem I have investigated two approaches. In the first approach, I used the 19 VISTA hydro scenarios, but weighted them with actual results from the BPA 50-water year data. In other words, I developed a histogram from the BPA data to determine how many times actual water years fell into each of the percentiles generated by VISTA. These weighting factors were then used in GRID. This data is shown in Figure 1 above.

In the second approach, I calculated a more realistic probability distribution based on the assumption that the Mid-Columbia and other Western hydro resources were independent, while the Eastern hydro moved in tandem with the Mid-Columbia hydro resources. While neither of these assumptions is perfectly accurate, they are much more realistic than the VISTA assumptions. This approach involved development of a matrix of 19-by-19 possible hydro scenarios, all with an equal likelihood of occurring.[17/] I then determined the hydro weights by developing a histogram to determine where each scenario fell into the respective VISTA scenarios. These results are also shown in Figure 1 above.

Results from both the BPA and calculated distributions produce average annual hydro generation that is virtually identical to that from

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[17] To develop an exact solution treating the Eastern resources as being independent would require a 19- by -19 by -19 tensor, which would greatly complicate these efforts. Given that the eastern hydro is much smaller than the other resources, the two dimensional approximation is not expected to be a major problem, though it will still tend to overstate the likelihood of extreme events and therefore power costs as well.

VISTA, but produces lower net power costs than the VISTA method. These results are shown in CCS Exhibit 6.11. The problem with VISTA is that it overstates the likelihood of extreme events. Extreme events produce asymmetric impacts on net power costs: extremely bad water years increase net power cost more than extremely good water years reduce it.

Q. WHICH OF YOUR TWO APPROACHES DO YOU RECOMMEND THE COMMISSION ADOPT?

A. I recommend use of the later approach as it builds upon the VISTA data. The GRID study based on the BPA data demonstrates, however, that the recommended method is conservative. For both methods the final results are quite close.

<u>Thermal Deration Factors</u>

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

A. In GRID, thermal deration factors (also called outage rates) control the amount generation available from thermal units. The more energy available, the lower net power costs. If a generator has an average 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 on outage. The Company uses a compilation of outages over the most recent forty-eight month historical period (April 2000 to March 2004) to compute the deration factors for its thermal plants. The purpose of using forty-eight months is to "normalize" or smooth out variations that might affect a single year.

Q. ARE THERMAL DERATION FACTORS AN IMPORTANT COMPONENT IN THE OVERALL LEVEL OF NET POWER COSTS?

A. Yes. PacifiCorp's thermal outage rates have increased substantially in the past five years. CCS Exhibit 6.12 shows that PacifiCorp's outage rates have increased by 30% compared to those used in the 1999 Utah rate case test year (Docket No. 99-035-10) for the same units. Because outage rates for larger units have increased more than outage rates for smaller units, this has resulted in an increase of 40% in capacity on outage (i.e., the average amount of capacity out of service due to forced outages) assumed in GRID. This is an increase of 287 mW, which is comparable to the expected capacity of the new Currant Creek CTs.

Q. HAS THE INCREASE IN OUTAGE RATES RESULTED IN INCREASED NET POWER COSTS?

A. Yes. To estimate the impact on the level of net power costs, I used GRID to compute the change in net power costs resulting from a 10 MW increase in coal capacity. I then applied this result to develop an annual average cost of the increased amount of capacity on outage. As shown in CCS Exhibit 6.12, the increase in net power costs is $38.4 million per year on a total Company basis or nearly $16 million per year on a Utah basis.

An associated problem is that the increase in outage rates has also led to a need for additional thermal capacity, further increasing system costs. The increase in capacity on outage (287 MW) is more capacity than the entire West Valley plant.[18/]

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

18/ Recall that the West Valley annual lease payment is $14.7 million.

A. The Commission should take a very careful look at the causes of these increased outage rates and make adjustments to remove outages that are imprudent, non-representative, or abnormal.

Q. HAVE YOU IDENTIFIED ANY OUTAGES THAT SHOULD BE EXCLUDED FROM THE FOUR-YEAR ROLLING AVERAGE?

A. Yes. I have identified several major outage events and a series of minor outages that should be excluded from net power costs. These are shown in CCS Exhibit 6.13. The most significant of these is the Hunter Unit 1 outage from November 2000 to May 2001.

Q. WHAT IS THE BASIS FOR REMOVING THE HUNTER OUTAGE?

A. This was clearly a catastrophic, one-time event and Utah ratepayers have paid for the cost of replacing the Hunter power as a result of the Stipulation in Docket No. 00-035-23.

Q. DID PACIFICORP REMOVE THE HUNTER OUTAGE FROM ITS COMPUTATION OF OUTAGE RATES USED IN GIRD?

A. PacifiCorp made an adjustment to exclude the Hunter outage from its calculation of the forced outage rates used in GRID. However, the Company did not fully reverse the impact of the outage.

Q. PLEASE EXPLAIN.

A. In making its adjustment, PacifiCorp deducted the number of hours the unit was on outage from the scheduled hours in the computation of the Operating Equivalent Availability Factor (OEAF). This calculation is supposed to compute outage rates by dividing the forced outage hours by scheduled outage hours. In effect, the Company treated the 3780-hour Hunter *forced outage* the same as a *planned outage* for this part of the calculation. This is simply incorrect as no planned outage was scheduled for Hunter Unit 1 during that time frame.

Q. ON WHAT BASIS DOES PACIFICORP JUSTIFY THIS TREATMENT?

A. In PacifiCorp's Response to CCS DR No. 27.1, the Company argued that it was correct to remove the Hunter outage period from the computation of the forty-eight month average. However, the Company proposes to use approximately a forty-two month rolling average for Hunter as compared to forty-eight months for all other units. In that case, the Company would assume outages in the missing six months would have been the same as the remaining forty-two months.

This is not a reasonable solution for ratepayers and seems opportunistic. The Company has long advocated use of a forty-eight month rolling average. The use of a truncated period should not be allowed as an arbitrary solution to benefit the Company.

Further, the outage rate in the remaining forty-eight months was quite high, and it is speculative to assume that Hunter 1 Unit would have had proportionally the same number of outage events during the long outage period from November 2000 to May 2001.

The selection of a period less than forty-eight months is also rather arbitrary. PacifiCorp could conceivably have selected a shorter or longer period and gotten different results, or simply used the forty-eight months prior to the November 2000 outage.

Hunter's OEAF for the remaining forty-two months was less than 85%. By contrast, the unit had an OEAF better than a 90% over the forty-eight months prior to the 2000 outage. Hunter Unit 1 is one of many units whose outage rates increased substantially (with or without the November 2000 outage) in the past five years. In effect, the Company seeks a reward due to its decline in performance.

Q. WHAT IS YOUR RECOMMENDATION?

A. The Commission should reject PacifiCorp's proposed treatment of the Hunter outage and remove <u>all</u> the costs associated with it from the test year. Reversing PacifiCorp's proposed adjustment to the scheduled service hours results in an OEAF of 88%. This is a more reasonable OEAF to use in this case, though it is still below historical levels for the unit prior to the 2000 outage. This results in a reduction to net power costs in the amount shown on line 13 of Table 1.

Q. ARE THERE OTHER QUESTIONABLE OUTAGE ASSUMPTIONS IN GRID?

A. Yes. In computing the forty-eight month average outage rate for the West Valley and Gadsby CTs, the Company used actual data for that period the units were in operation (June 2002 to March 2004) and a mature forced outage rate for remaining time.

During this period of testing and initial operation, these units experienced an extraordinary number of outages. As a result, their outage rates averaged nearly 20%, and individual units had outage rates of 30%-45%. It is typical for new plants to experience problems in the initial months of operation. The Company improperly assumes that these outages will continue to occur in the test year.

In the comparable case of the Hermiston plant in Utah rate case Docket Nos. 97-035-01, 99-035-10, and 01-035-01, the Company assumed that a mature forced outage rate would be more indicative of normal conditions until a reasonable period of historical data was obtained. The Company also assumes a mature outage rate for the Currant Creek plant in this proceeding, using a level consistent with the assumptions made in the certification proceedings.

If the poor performance of Gadsby and West Valley is representative of future conditions, the Company should not be rewarded for that either. I recommend using a mature outage rate that actually exceeds the figure PacifiCorp assumed for Current Creek, (Confidential) Use of a mature outage rate results in a reduction to power costs in the amount shown on line 15 of Table 1.

Q. EXPLAIN THE CIRCUMSTANCES SURROUNDING THE OUTAGE AT JIM BRIDGER UNIT 4 IN JUNE 2000.

A. This was a 315-hour outage resulting from a main transformer failure. This outage represents a case in which the Company has already admitted culpability. This is shown in the following excerpt from the cross-examination of PacifiCorp witness Barry Cunningham in Wyoming Docket No. 20000-ER-02-184.

> Q. (BY CHAIRMAN ELLENBECKER) Mr. Cunningham, have you ever been involved in a situation with PacifiCorp where there was an issue surrounding maintenance or testing or equipment integrity for a generation facility where the company did an examination *and acknowledged either human or equipment or testing failure of its own making as being the fault*?
>
> A. Yes, sir.

Q. Can you illustrate one of those?

A. The most recent one that comes to mind was a main transformer failure at the Jim Bridger Plant, and it would have been in the summer, I believe, of 2000. It was on, I believe, Jim Bridger 4 if I've got the units straight.

* * *

We had a spare transformer. It took us about two weeks, 13 days, as I recall, to replace it. This was again during the high-price power period, too. [Transcript Of Hearing Proceedings, Volume IV January 13, 2003, page 558. (emphasis added)]

CCS Exhibit 6.14 is a copy of the entire section of the transcript quoted above and it provides a more detailed description of the Bridger 4 outage event. Because this outage was the result of imprudence, it should be removed from net power costs as shown on line 16 of Table 1.

Swift Canal Failure

Q. DESCRIBE THE CAUSE AND IMPACT OF THE SWIFT DIVERSION CANAL FAILURE.

A. In April 2002 the diversion canal at Swift collapsed. According to a report by CH2M Hill (commissioned to study the event), this was due to a lava tube that filled with water and created a large sinkhole near the diversion canal, which ultimately collapsed[19/]. This was a catastrophic failure that rendered it impossible to operate Swift Units 21 and 22 until repairs had been made. The most substantial impact on net power costs was that it prevented the Swift Station 1 (which is upstream) from carrying operating reserves.

Q. WHEN WILL THE FACILITY BE RETURNED TO SERVICE?

[19] CCS **Exhibit 6.15 is the Report to the Federal Energy Regulatory Commission on Failure of the Swift No. 2 Power Canal Embankment CH2M Hill January, 2003, page 81-82.**

A. CCS Exhibit 6.16 shows the rehabilitation schedule summary. This document was obtained from discovery in the recent Washington general rate case (UE-032065, data request ICNU5.2). The document shows Unit 22 having an on line goal of March 2005, and Unit 21 having an on line goal in July 2005. The work was expected to be substantially complete by August 30, 2005 with only “punchlist” items needing completion before the final project acceptance on November 1, 2005. Based on PacifiCorp’s response to CCS15.1, there is a slight delay in this schedule, but the work will be fully complete by January 1, 2006. Based on the Company’s response to CCS 15.3, some costs related to the repair have been included in the test year.

Q. HOW SHOULD THE COMMISSION DEAL WITH THIS ISSUE?

A. The Commission must decide on what date to show the project as being fully in service during the test year. The work is expected to be completed by January 1, 2006, but the units are expected to begin generation long before that. Once generation begins, it will be possible to start carrying reserves on Swift again. Based on the rehabilitation schedule discussed above, work was expected to be substantially complete only a few months into the test year. Given the Swift units will be fully operational prior to the end of the test year, (and that the Station is expected to begin generating before the start of the test year), I recommend assuming the units to be in service for the entire test year.

The fact that this was such an unusual event further argues in favor of assuming (for the purposes of normalized rates) that the units should be treated as fully operational for the entire test year. In no case should it be reflected as being in full service any later than January 1, 2006. Table 1 shows the reduction to net power costs based on the Swift Station being on line the entire 2006 fiscal year.

Q. HOW HAS THIS ISSUE BEEN TREATED IN OTHER JURISDICTIONS?

A. To my knowledge, the Company has never reflected the inability of the Swift Station to carry reserves in rates in any state. While the event occurred in April 2002, it was not reflected in the GRID runs in either the 2003 Oregon (UE-147) or Utah (Docket No. 03-035-10) rate cases. The Company proposed to reflect this item in its most recent Wyoming rate case (Docket No. 20000-ER-03-198) as a late filed update, but the Commission rejected the proposal. Furthermore, the Company recently agreed in the Washington rate case to normalize out the event for the entire FY 2004 test year, even though the units were not expected to return to full service at the start of the rate effective period. For all these reasons, I recommend against including these additional costs on the cusp of the Swift units full return to service.

Q. WHAT IS YOUR RECOMMENDED ADJUSTMENT RELATING TO THE SWIFT CANAL FAILURE?

A. Since the Swift Units are expected to be operational in the test year, I recommend excluding the increase in reserve costs that are reflected in the Company's GRID results. My adjustment reduces net power costs as shown on line 14 of Table 1.

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THE SWIFT ISSUE?

A. All adjustments to GRID impact all other adjustments to the model. However, more than any other issue, the numerical value of this adjustment is quite dependent on its order in the series of adjustments to GRID. The level of this adjustment increases from $1.5 million to more than $5.6 million if it is included before or after the modification to spinning reserve modeling discussed above. The Commission should keep this in mind in when determining the overall level of net power costs in this case.

Q. HAVE YOU IDENTIFIED OTHER CIRCUMSTANCES REQUIRING AN ADJUSTMENT TO THE PACIFICORP OUTAGE RATES?

A. Yes. There are two more instances where circumstances surrounding outages appear highly unusual and clearly non-representative of future conditions.

In the <u>first</u> instance, I discovered an extremely high number (41) of main transformer incidents at Hunter Units 1 and 2. The Company apparently recognized that this was an excessive number of incidents and took steps to address it. The Company has now engaged in a program of acquiring additional spare transformers, improved monitoring and other new procedures, designed to resolve these problems.[20/] Further, the capital costs of such repairs have been reflected in the rate base. In the case of Hunter Unit 2, there was a replacement made of the 2-2 main transformer in September 2001. There were no additional reported forced outages due to this cause in the remainder of the historical period (ending March 31, 2004).

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THIS ISSUE?

A. Whatever the cause of these problems, the Commission should recognize three important points. First, this level of outages is high compared to other PacifiCorp plants. Second, the Company has taken steps to address the problem. Third, the Company seeks recovery of the costs of addressing the transformer problem in base rates. While there are always outages at generators and repair costs associated with addressing them, in this instance the problems were unusual and should not be expected to reoccur on a systematic basis. Thus, I recommend the associated outage events be reversed out of the GRID study, resulting in a reduction to net power costs in the amount shown on line 17 of Table 1.

Q. WHAT WAS THE SECOND ABNORMAL OUTAGE SITUATION YOU REFERENCED ABOVE?

A. The second example is less significant, but still requires an adjustment. The Blundell geothermal unit suffered a 3 MW deration from October 1998 to May 2001. This was due to turbine rotor stress corrosion cracking. This led to a one-month outage to install a new turbine. This problem has now been corrected and the Company has included $3.2 million in capital costs related to the new turbine in the test year.[21/]

However, PacifiCorp's normalization approach effectively assumes this problem was never addressed and will continue to occur indefinitely. I recommend removal of this problem, resulting in a decrease in test year net power costs as shown on line 18 of Table 1.

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[20] Data Response ICNU 1.71 (again from the recent Washington case, Docket No. UE-032065).

[21/] *See* the Company's response to CCS8.19.

Q. ARE THERE ANY CATASTROPHIC OUTAGES THAT SHOULD BE REMOVED FROM THE FOUR-YEAR ROLLING AVERAGE?

A. Yes. In July 2000, the Company experienced an 1815-hour outage at Hayden Unit 1 and in July 2001, the Company had a 389-hour outage at Colstrip Unit 4. PacifiCorp proposed a normalizing adjustment for both outages in its requested net power costs in an Oregon rate case, UE 134.[22/] The Company later proposed a similar adjustment in Wyoming Docket No. 20000-ER-02-184, but later withdrew it. The basis for my proposed adjustment is the Company's recognition that these events are non-recurring in nature.

The Company also included both outages on a list of catastrophic outages in the Utah Hunter/Excess Power Cost case.[23] This is significant because in that case the Company indicated that it did not make forward purchases to cover the possibility of such catastrophic outages. This argument was used by the Company to justify higher purchased power costs with the Hunter outage. Further, the cost of the Colstrip Unit 4 outage was previously reflected in the costs recovered during the excess power cost deferral period (from May to September 2001). Thus, failure to reverse this outage will lead to double recovery of costs for the same event.

Consequently, I recommend removal of these unusual and catastrophic outage events as well. These adjustments reduce net power costs by the amount shown on lines 19 and 20 of Table 1.

22/ While the Company did not propose any adjustment in Docket No. UE-147 (Oregon) and Docket No. 03-2035-02 (Utah), this issue was a factor during settlement discussions. As these cases settled, there is no evidence to prove these outages were included or excluded in those states.

Q. ARE THERE ANY ADDITIONAL ISSUES RELATED TO GENERATOR OUTAGES?

A. Yes. The Bridger Unit 4 outage previously discussed is not the only example of an imprudent outage reflected in the GRID study. During the four-year historical period, the Company reported numerous other outage incidents to the NERC under the categories of "Operator Errors," "Maintenance Errors," "Subcontractor Errors" or "Other Safety Problems." These incidents resulted in approximately 3.35 MW of lost generation on an average hourly basis in the four-year historical period. These are imprudent outages and customers should not bear the associated costs.

Mr. Widmer's cross-examination in the recent Wyoming case (in relation to the imprudent Jim Bridger Unit 4 main transformer outage) underscores the need to address the rate treatment of these kinds of problems.

> Q. And are you aware that's the outage that one of the company's witnesses earlier said was the company's fault in the testimony that we just had over the past few days?
>
> A. Yeah. I believe Mr. Cunningham indicated that that was something that was a result of company actions. And we still don't recommend that that type of outage should be removed from the company's calculation. As in any business, you know, accidents happen, errors happen and so forth, and so *it appears to us that it's more of a normal occurrence.*
>
> *If, in fact, the company had a history of an exorbitant number of human errors in relation to this, I would expect the Commission to take notice of that.*

CCS Exhibit 6.17 [Excerpt of Transcript Of Hearing Proceedings, Volume VII, January 16, 2003, page 1220) (emphasis added)].

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[23] See CCS 14.1, Docket No. 00-035-23.

As Mr. Widmer has testified, the Commission should *take notice* of the large number of outages due to these kind of errors.

Q. IS THIS JUST "BUSINESS AS USUAL" FOR PACIFICORP?

A. Unfortunately, it appears to be the case. However, it does not need to be so. It is quite telling that for the four-year period ending December 1997, the Company reported only 112 hours of lost generation due to these four error categories. For the four-year historical period ending March 31, 2004, the Company reported 318 hours of lost generation, an increase of 285%! Clearly, this represents an unacceptable decline in performance.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THIS ISSUE?

A. I recommend removing these costs from the test year. This results in a decrease to net power costs of in the amount shown on line 21 of Table 1 and CCS Exhibit 6.18.

<u>Wind Resource Modeling</u>

Q. DO YOU AGREE WITH PACIFICORP'S MODELING OF WIND RESOURCES?

A. No. The Company assumes that on a daily basis, wind resources follow a flat output curve. However, this ignores the fact that wind resources tend to provide more generation during the peak hours of the day. Based on analysis of hourly dispatch data for the Foote Creek wind unit, I developed a more representative hourly output shape resulting in the adjustment shown on Table 1. While this adjustment is not large, it should be reflected in the test year.

<u>Other Related Power Cost Adjustments</u>

Q. IS THE GRID ESTIMATE OF TRANSMISSION EXPENSE FOR FY 2006 REASONABLE?

A. No. The figures used in GRID are overstated. Based on the Company's response to DPU 3.38, the Company included $7.0 million for expected ISO activity. The response indicates that ISO activity will not be as substantial as previously expected. A more realistic assumption is that ISO expenses will be $1.5 million, resulting in a reduction to net power costs in the amount shown on line 24 of Table 1.

Q. ARE THERE OTHER POWER COST ADJUSTMENTS SHOWN ON TABLE 1?

A. Yes. Mr. Hayet testifies in support of long-term contract adjustments related to the US Magnesium, Desert Power, Tesoro and Kennecott contracts. He also proposes a loss factor adjustment. I have reflected these items on lines 8,9, 10 and 23 of Table 1.

Q. ARE THERE ANY ISSUES RELATED TO THE COST OF THE GADSBY COMBUSTION TURBINES?

A. Yes. The installed cost of the Gadsby CTs was exceptionally high (approximately $667/kW.) In the Gadsby Certification case (Utah Docket No. 00-035-37), the Company contended that one of the benefits of the Gadsby project was the fact that General Electric (GE) had agreed to an early termination of a rental agreement for some temporary CTs at the Gadsby site. This resulted in a savings of $7.5 million for PacifiCorp. This benefit flowed directly through to the Company and has not been reflected in Utah rates. Had the Company obtained a simple $7.5 million price concession on the cost of the peaking units from GE, the Gadsby rate base would be reduced. I am concerned that PacifiCorp had a conflict of interest in negotiating the purchase price of the Gadsby CTs, as it may have had to choose between a lower permanent cost for ratepayers versus a one-time $7.5 million cost savings for PacifiCorp.

Q, DO YOU WISH TO PRESENT ANY DOCUMENTS THAT SHED LIGHT ON THIS ISSUE?

A. Yes. CCS Exhibit 6.19C (Confidential) is a copy of a portion of a PacifiCorp exhibit (Morrison Exhibit 6) presented by the Company in the Gadsby Certification case, Docket No. 00-035-37. This document is a summary of information provided to the ScottishPower Board concerning the project. There are two interesting items contained in the Board presentation. First, the Board presentation states:

(Confidential)

(CCS Exhibit 6.19C)

I believe this establishes three important points. (Confidential)

This is a classic case of a conflict of interest that the Commission should resolve in favor of the ratepayers. I recommend the Commission decrease the level of the Gadsby CT plant investment by $7.5 million. The impact of this adjustment based on PacifiCorp's requested ROE is shown on line 2 of Table 1.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.