6. PacifiCorp uses loss factors that overstate energy losses for Washington as compared to other WCA states. This problem overstates the fixed costs allocated to Washington, as well as the total WCA production costs. More realistic loss factor assumptions (based on five years of actual data) results in a reduction to revenue requirements in the amount shown on Table 1.

Net Power Cost (GRID Adjustments)

Short-Term Firm Transaction Adjustments

1. The short-term firm transactions modeled in GRID show a disproportionate number of below-market sales. The Company has not demonstrated these transactions are prudent or necessary to provide service to Washington, and they fail the Commission's used and useful test. Removal of these transactions results in a reduction to net power costs in the amount shown on Table 1.

Long-Term Contract Adjustments

2. PacifiCorp imputes a price to the Sacramento Municipal Utility District ("SMUD") contract of $37/megawatthour ("MWh") based on a previous Southern California Edison ("SCE") contract price. This treatment was first used by the Utah Public Service Commission ("UPSC") because it found the SCE contract to be a prudent, contemporaneous contract that established a benchmark price for SMUD. Because the SCE contract has expired it is no longer an appropriate benchmark and the WUTC should develop its own policies regarding this contract. I recommend the SMUD contract be removed from GRID, reducing power costs by the amount shown on Table 1.

3. PacifiCorp failed to replace all of the capacity of the Centralia plant when the resource was sold. The TransAlta contract replaces only 74% of the plant's energy. Because the Company retained 50% of the ~~gain~~ appreciation on the Centralia sale, it should assume 50% of the risk associated with its failure to replace all of the associated capacity and energy. This adjustment reduces net power costs by the amount shown on Table 1

4. PacifiCorp overstates the likely generation from the Georgia-Pacific ("GP") Camas cogeneration facility compared to recent actual data and current trends. Correcting this problem reduces net power costs as shown on Table 1.

Modeling Adjustments

5. PacifiCorp's Vista modeling of 40 water years of data should be modified to exclude water years resulting in power costs that are more than one standard deviation from the mean. This treatment was proposed by the WUTC Staff in Docket No. UE-032065 and accepted by the Company and Commission in

Table 1 quantifies the impact on net power costs associated with implementing each of my proposed adjustments.

$1000	Total PACW	Washington Jurisdiction CAEW 22.5244%
I. Jurisdictional Allocation Issues		
WCA Model Corrections	N/A	-$23,482,877
1 Interconnection Benefits	N/A	-$8,567,749
2 Johnson/Wyodak Part 1 (Actual Flow)	N/A	-$3,842,443
3 Johnson Wyodak Part 2 (Include E WY)	N/A	-$8,243,613
4 CAGW Allocation Factor	N/A	-$2,192,439
5 Historical Loss Factors	N/A	-$636,633
II. GRID (Net Power Cost Issues)		
A. Short-Term Firm Adjustments	-$35,235,790	-$7,936,636
6 Remove Short-term firm	-$35,235,790	-$7,936,636
B. Long Term Contract Adjustments	-$20,361,095	-$4,586,206
7 SMUD Contract	-$12,299,225	-$2,770,322
8 TransAlta/Centralia Risk Sharing	-$7,924,453	-$1,784,932
9 GP Camus	-$137,417	-$30,952
B. Modeling Issues	-$8,306,219	-$1,870,923
10 Hydro Water Year Modeling	-6,966,525	-$1,569,165
11 Monthly Outages	655,539	$147,656
12 Ramping	-$1,149,401	-$258,895
13 Regulating Margin Modeling	-$845,832	-$190,518
Total Power Cost Adjustments -	-$63,903,104	-$14,393,765
PacifiCorp GRID Request	$417,037,230	$93,934,968
Adjusted GRID Result	$353,134,126	$79,541,203
Total Adjustments	N/A	-$37,876,642

Q. HOW IS THE REMAINDER OF THIS TESTIMONY ORGANIZED?

A. In Section II, I address the jurisdictional allocation (WCA model) issues. In Section III, I address net power cost (GRID model) issues. In Section IV, I am testifying on behalf of only ICNU and I address PacifiCorp's proposed PCAM.

> ***market risks***, and additionally bear the regulatory burden of prudently managing their resources, which multiple ownership can make difficult. As both shareholders and ratepayers have incurred risks and burdens, both should also share in the benefits of the sale. The remaining gain is thus *one* of the benefits, which, when considered with other benefits and burdens, must be fairly allocated.[27]
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> * * *
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> Given the risks and burdens borne by the ratepayers and shareholders, and given the other benefits they stand to gain from the sale, we find that it is fair in this case to allocate the appreciation between ratepayers and shareholders. When we apply the principles of *Democratic Central* to the facts of this case, we conclude that one half of the appreciation should go to shareholders, and one half to ratepayers.[28]

In reaching this decision, the Commission enunciated a policy that would share the ~~gain~~ appreciation on the sale equally between customers and shareholders, while at the same time sharing the risks (most notably market risk.) In the case at hand, the Company has conveniently ignored this fact, and instead proposes to place the entire risk of higher power market prices on the customer. Since the Company retained half of the ~~gain~~ appreciation from the sale, under the principle that *risk should follow reward*, it should bear half of the risk. Under these circumstances it is not reasonable to shield the Company from all of the risks of its controversial decision to sell the plant.

Q. DID THE COMPANY OBTAIN SUFFICIENT ENERGY FROM THE TRANSALTA BUYBACKS TO REPLACE CENTRALIA?

A. No. The Company obtained only enough energy from the buybacks to replace 74% of the Centralia generation for the test year. Given that the Company was well aware at the time of the sale that there was certainly substantial market risk

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[27] Id. at ¶ 84 (emphasis added).
[28] Id. at ¶ 86.

associated with the transaction, its decision to replace only part of the generation for the plant was questionable to say the least. This shortfall resulted in an increase in purchased power costs of nearly $16 million on a PACW basis and approximately $3.6 million for Washington under the WCA model. Even more significant is the fact that after June 2007, the TransAlta buybacks terminate and the Company will be left without any permanent supply to replace the Centralia generation. This contract termination will result in additional costs per year of $45 million for PACW, and, under the WCA method, added costs of $10 million per year for Washington. The Company assumes customers should bear 100% of these added costs. This is not a reasonable rate treatment in light of the Commission's principle that risk should follow reward.

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

A. As discussed above, the Commission decided to give the Company the opportunity to make the sale, and also apportioned 50% of any associated ~~gain~~ appreciation to the Company. Under these circumstances, it is unreasonable to saddle ratepayers with all of the risks that have resulted from the sale. Unless the Commission apportions some of the costs of the unreplaced power to the Company, the ratepayers will have been given 50% of the ~~gain~~ appreciation on the sale, but bear 100% of the risks. As a result, I recommend that 50% of the cost associated with additional replacement power costs for Centralia be allocated to the Company. This adjustment reduces the requested claim by the amount shown on Table 1. Unless this adjustment is made, an unreasonable shifting of the risks of the Centralia sale between the Company and ratepayers will occur.

and similar designs, one would expect that if the monthly outage rate modeling made sense, there should be some correlation between their monthly outage rates. In other words, if there are causal factors that result in a definite monthly pattern of outages, it should affect all units at the station in a comparable manner. However, the exhibit shows there really is no discernable pattern in the monthly outages of these units. Indeed, there is no statistically significant correlation between the monthly outage rates of these units. It is apparent from the figure that the monthly variations about the mean amount to nothing more than "statistical noise" or "random chance." This strongly suggests there is no basis, other than superstition, underlying the Company's proposal to apply this novel monthly outage rate modeling technique.

Q. DOES THE MONTHLY OUTAGE RATE MODELING INCREASE NET POWER COSTS IN GRID?

A. Yes. Given the lack of a sound engineering basis or common sense argument underlying this approach and the lack of any statistical support for it, I am forced to conclude this is little more than "numerology." ~~It certainly appears this is a one-sided adjustment proposed by the Company for no purpose other than to increase power cost estimates.~~ I recommend that the Commission reject the monthly modeling of outage rates and reduce net power costs by the amount shown on Table 1.