BEFORE THE IDAHO PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF A GENERAL RATE INCREASE OF	))))))))	DOCKET NO. ID PAC-E-10-07

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UTILITIES COMMISSION

DIRECT TESTIMONY OF

MARK T. WIDMER

ON BEHALF OF

MONSANTO

November 1, 2010

TABLE OF CONTENTS **PAGE**

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark T. Widmer and my business address is 27388 S.W. Ladd Hill Road, Sherwood, Oregon 97140.

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

A. I am a utility regulatory consultant and Principal of Northwest Energy Consulting, LLC ("NWEC"). I am appearing on behalf of Monsanto.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. With NWEC, I provide consulting services related to electric utility system operations, energy cost recovery issues, revenue requirements, and avoided cost pricing for qualifying facilities. Since forming NWEC, I have provided testimony in dockets regarding recovery of net power costs through general rate cases and power cost adjustment mechanisms and avoided cost methodologies in Wyoming and net power costs and the prudence of resource acquisitions in Washington. Prior to forming NWEC, I was employed by PacifiCorp. While employed by PacifiCorp, I participated in and filed testimony on power cost issues in numerous dockets in Wyoming, Oregon, Utah, Washington, Idaho, and California jurisdictions over a 10 plus year period. At the time of my departure from PacifiCorp, I was the Director of Net Power Costs. My full qualifications and appearances are provided in Exhibit Monsanto 228 (MW-1).

II. PURPOSE OF TESTIMONY AND SUMMARY OF ADJUSTMENTS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses PacifiCorp's Generation and Regulation Initiatives Decision ("GRID") model which was used to calculate normalized Net Power Costs ("NPC") for the forecast test period ending December 31, 2010.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony presents fifteen NPC adjustments totaling $47.02 million total Company and $2.55 million Idaho. As discussed in my following testimony, those adjustments are made to reflect realistic operation of PacifiCorp's system, match costs with benefits, make corrections and reflect reasonable results. My adjustments are summarized on Table 1 below and subsequently explained in more detail in the remainder of my testimony.

Table 1
Summary of Recommended Adjustments - $

		Total Company	Primary Recommendation Idaho Est.	Secondary Recommendations Idaho Est.
GRID (Net Variable Power Cost Issues)				
	PacifiCorp Request NPC	1,069,701,315	63,465,379	
ADJUSTMENTS				
1	APS Supplemental (Coal +Other)	-1,942,838	-115,269	
2	Wind Integration Costs	-34,187,931	-1,883,242	
	2a OATT Wind integration Costs	-6,361,994		-350,450
	2b Balancing Wind Integration Costs	-2,629,076		-144,823
3	Non-Firm Transmission	-2,432,988	-144,349	
4	Dunlap Reserve Requirement	127,222	7,548	
5	Reserve Shutdowns	-807,546	-47,912	
6	Top of World Wind	1,550,033	91,963	
	6a Top of World Incremental Wind Integration	285,266		15,714
7	Cal ISO	-3,713,698	-204,569	
8	Colstrip Planned Outages	-258,678	-15,347	
9	Energy Gateway Transmission	3,291,265	195,271	
10	Cholla 4 Capacity	-1,113,498	-66,064	
11	Morgan Stanley Call Premiums	-3,057,000	-168,395	
12	Bear River Hydro Normalization	-2,181,474	-129,427	
13	Black Hills Shaping	-1,293,489	-76,743	
14	Mona Market	-438,529	-26,018	
15	Naughton 3 Outage	-559,329	-33,185	
	Allocation True-UP		69,851	
Total Adjustments Primary Recommendation		-47,018,478	-2,545,886	
Est. Allowed - NPC Primary Recommendation		1,022,682,837	60,919,493	
Est. Idaho Jurisdiction				
SE: 6.3575%				
SG: 5.5085%				

Adjustment 1. **APS SUPPLEMENTAL OPTION**

The Company has an option to purchase supplemental energy offered pursuant to the Long Term Power Transaction Agreement with Arizona Public Service ("APS"). While the option is continually exercised during actual operations, it is uneconomic as modeled in GRID. Since the purchase is optional and uneconomic it should be excluded from NPC. This adjustment reduces NPC by $0.12 million on an Idaho basis.

Adjustment 2. **<u>WIND INTEGRATION COSTS</u>**

The Company used the wind integration rate of $6.50 per MWh that was adopted by the Commission for avoided cost rates for qualifying facility contracts to calculate wind integration costs. This rate has no basis on the Company's actual wind integration costs and the Company has therefore, not met its burden of proof regarding recovery of wind integration costs. Consequently, I recommend that the Commission reject recovery of wind integration costs using the $6.50 per MWh rate and recommend that wind integration costs be recovered through the Company's ECAM as it is the best solution to recovering actual wind integration costs. This adjustment reduces NPC by $1.88 million on an Idaho basis. I also recommend that the Commission adopt the premise of my secondary adjustment 2a OATT Wind Integrations Costs, so that the Company not be allowed to recover wholesale wheeling customer wind integration costs from retail customers through the ECAM. If the Commission does not adopt my proposed recommendation, my secondary recommendation is to adopt the following adjustments 2a OATT Customer Wind Integration Costs and 2b Balancing Wind Integration Costs.

Adjustment 2a. **<u>OATT CUSTOMER WIND INTEGRATION COST</u>**

The Company included wholesale wheeling customer wind integration costs in NPC because the Company has failed to request an adjustment to their OATT so that these costs can be recovered from wholesale wheeling customers. These costs are not the responsibility of Idaho customers and should be removed from NPC. This adjustment reduces NPC by $0.35 million on an Idaho basis.

Adjustment 2b. **BALANCING WIND INTEGRATION COSTS**

The Company double counted wind integration balancing costs during the period January 2010 through April 2010. This adjustment removes the double count and lowers NPC by $0.14 million on an Idaho basis.

Adjustment 3. **NON-FIRM TRANSMISSION**

In actual operations the Company utilizes a significant amount of non-firm transmission to use of assets included in rates more efficiently in the system balancing and optimization process. However, non-firm transmission was excluded from NPC, thereby producing a suboptimal dispatch of the system and higher net power costs. I recommend that non-firm transmission be included in GRID to match costs and benefits. This adjustment reduces NPC by $0.14 million on an Idaho basis.

Adjustment 4. **DUNLAP RESERVE REQUIREMENT**

This adjustment incorporates the costs of carrying operating reserves for Dunlap, which were omitted from the original filing and increases NPC by $0.01 million on an Idaho basis.

Adjustment 5. **RESERVE SHUTDOWN EFOR COMPONENT**

The Company's inclusion of reserve shutdowns in the GRID forced outage rate calculation input causes an overstatement of generation lost due to forced outages because the calculation is inconsistent with how GRID calculates generation lost due to forced outages. I recommend exclusion of reserve shutdowns from the forced outage rate calculation for all plants except for natural gas peaker units. This adjustment reduces NPC by $0.05 million on an Idaho basis.

Adjustment 6. **<u>TOP OF WORLD WIND</u>**

During the discovery process the Company informed Monsanto that the expected online date for the Top of the World wind project had been moved forward from November 1, 2010 to October 1, 2010. This adjustment includes the new online date and increases NPC by $0.09 million on an Idaho basis.

Adjustment 6a. **<u>TOP OF WORLD INCREMENTAL WIND INTEGRATION</u>**

If the Commission does not adopt my primary recommendation to recover wind integration costs through the ECAM, this adjustment includes incremental integration costs associated with moving the expected in service date from November 1, 2010 to October 1, 2010.

Adjustment 7. **<u>CAL ISO EXPENSES</u>**

The filing includes a full year estimate of Cal ISO wheeling and service fees. However, the filing does not include any transactions that would incur CAL ISO fees beyond May 3, 2010. Accordingly, I recommend disallowance of all Cal ISO fees for the period May 4, 2010 through December 31, 2010. I also recommend that actual Cal ISO fees be included for the period prior to May 4, 2010 to match costs with the actual wholesale transactions included in the filing. This adjustment reduces NPC by $.20 million on an Idaho basis.

Adjustment 8. **COLSTRIP PLANNED OUTAGES**

This adjustment moves the planned outage starting dates for Colstrip 3 and Colstrip 4 from September to May to better optimize the Company's system.

The revised planned outage dates reduce NPC on an Idaho basis by $0.02 million.

Adjustment 9. **ENERGY GATEWAY TRANSMISSION**

This adjustment removes the Energy Gateway transmission project from NPC to be consistent with Mr. Peseau' Energy Gateway transmission adjustment and increases NPC by $0.20 million on an Idaho basis.

Adjustment 10. **CHOLLA 4 CAPACITY**

The Company's modeling understates Cholla 4 capacity. My adjustment corrects the capacity and reduces NPC by $0.07 million on an Idaho basis.

Adjustment 11. **MORGAN STANLEY CALL PREMIUMS**

The Company's filing includes two call option purchase power contracts that are uneconomic. This adjustment removes both contracts and lowers NPC by $0.17 million on an Idaho basis.

Adjustment 12. **BEAR RIVER HYDRO NORMALIZATION**

The Bear River historical record was adjusted by the Company to remove flood control years, which are years when surplus water was released from Bear Lake. The Company believes the adjustment is reasonable because the region is currently impacted by a long-term drought and a low water level at Bear Lake. This is one-sided because it is different than the normalized methodology used to normalize all other hydro resources and is not appropriate for normalized ratemaking. I recommend that the flood control years excluded from NPC be included in NPC to be consistent with the modeling of other hydro resources. My recommendation reduces the NPC by $0.13 million on an Idaho basis.

Adjustment 13. **Black Hills Sales Shaping**

The Company bases its modeling of the Black Hills wholesale sales on the faulty assumption that Black Hills will dispatch the contract during the highest costs hours. Historical dispatch of the contract demonstrates that this is not the case. I recommend that the contract be dispatched based on a four-year average of historical results. This adjustment reduces NPC by $0.08 million on an Idaho basis.

Adjustment 14. **MONA MARKET**

The Company limited the size of the Mona wholesale market, allegedly based on trading experience of their Front Office. Historical information shows that the Mona market was significantly undersized. I recommend that the size of the Mona market be corrected based on a four-year average of actual information. This adjustment reduces NPC by $0.03 million on an Idaho basis.

Adjustment 15. NAUGHTON 3 OUTAGE

The Company collected liquidated damage payments from its contractor Siemens for failure to complete a contract on schedule due to poor performance. The Company seeks to recover the cost of this outage again by including it in GRID planned outage inputs. Accordingly, I recommend that the planned outage be removed from GRID. This adjustment removes the outage and reduces NPC by $0.03 million on an Idaho basis.

Finally, in response to Monsanto data request 2.33 the Company stated:

> Prior to its rebuttal the Company anticipates additional changes to various components of the net power costs, including but not limited to the new Official Forward Price Curve and new short-term firm electricity and natural gas transactions.

This very late update does not provide the Parties adequate time to review the significant amount of data tied to the stated update. Therefore, I recommend that the Commission reject all Company proposed rebuttal updates to NPC except corrections related to the original filing so that the Parties other than the Company are not disadvantaged by the late update.

III. DETAILED ADJUSTMENTS

Q. BEFORE YOU DISCUSS YOUR ADJUSTMENTS IN DETAIL, PLEASE EXPLAIN NPC AND ITS IMPORTANCE.

A. NPC is defined as the sum of purchased power expense, wheeling expense and fuel expense less wholesale sales revenues. Review and determination of the appropriate NPC is very important because it represents one of the Company's single largest revenue requirement components and establishes the ECAM baseline. NPC is calculated by the Company's GRID production dispatch model.

Adjustment 1. **ARIZONA PUBLIC SERVICE ("APS") SUPPLEMENTAL ENERGY**

Q. PLEASE EXPLAIN THE APS SUPPLEMENTAL ADJUSTMENT.

A. Pursuant to the terms of the Long-Term Power Transactions Agreement between APS and PacifiCorp, APS is required to offer PacifiCorp 219 GWH of Supplemental Coal Energy and 876 GWH of Other Supplemental Energy through October 31, 2020, when the contract expires. The Company has the option but not the requirement to purchase either the Supplemental coal or Other Supplemental energy or both at prices offered by APS for each product.

Q. IS THE CONTRACT ECONOMIC AS MODELED IN GRID?

A. No. Both the Other Supplemental and the Supplemental Coal components are modeled uneconomically in GRID.

Q. HOW DID YOU DETERMINE THE CONTRACT WAS UNECONOMIC?

A. I ran the GRID model without the Supplemental Coal and Other Supplemental energy. The runs reduced NPC by approximately $1.95 million total Company. The contract is therefore uneconomic for customers as modeled by the Company and should be excluded from NPC. This adjustment reduces the NPC by $0.12 million on an Idaho basis.

Q. HAS THE COMPANY AGREED TO THIS METHODOLOGY IN OTHER JURISDICTIONS?

A. Yes. In the stipulation for Oregon Docket UE 216, the Company agreed to model the APS Supplemental Coal and Other option contract only when economic for future filings.

Adjustment 2. <u>**WIND INTEGRATION COSTS**</u>

Q. HAS THE COMPANY MET ITS BURDEN OF PROOF ON WIND INTEGRATION COSTS?

A. No. While the Company has done numerous forecasts of wind integration costs over the last several years, which have varied from a little over $1 per MWH to approximately $9 per MWh for 2011 in a recent draft study, they still cannot tell us what their actual wind integration costs are. In WIEC Data Request 5.6 from Wyoming Docket No. 20000-352-EP-09 the Company was asked to provide the actual reserve intra-hour reserve requirement for wind generation located within their control area. In response, the Company stated:

> The Company objects to this question on the basis that it is overly burdensome and would require the Company to perform analysis not previously performed. Notwithstanding this objection, the Company states as follows.
>
> The Company holds reserves to maintain reliability of its system in accordance with standards set by the Western Electricity Coordinating Council. Reserves held are not differentiated such that the Company can identify the intra-hour reserve requirement isolated for wind generation.

Without knowing what the Company's actual costs are it is very difficult to determine the reasonableness of Company's requested recovery of $34.2 million for wind integration costs.

Q. IS THE COMPANY'S PROPOSED USE OF THE $6.50 PER MWH COST OF WIND INTEGRATION RATE APPROVED BY THE IDAHO COMMISSION IN CASE NO. PAC NO.-E-09-07, A REASONABLE SOLUTION TO THE COMPANY'S LACK OF VERIFIABLE INFORMATION?

A. It is a solution, but it is not the best solution, because the adopted wind integration rate is not based on the Company's system costs. The rate was adopted specifically to be used in the determination of avoided cost rates. To date the Company has not entered any Idaho based wind qualifying facility contracts, so the adoption of the rate for avoided costs has not placed customers at risk of paying too much. However, requesting recovery of over $34 million for wind integration costs in this case based on the $6.50 per MWh rate is a different matter as it places customers at risk of paying too much.

Q. WHAT IS YOUR RECOMMENDATION?

A. The Commission should reject the Company's request for recovery of wind integration costs using the $6.50 per MWh rate approved for avoided cost rates because their burden of proof has not been met. Due to the significant size of these costs, recovery should occur through the ECAM. Only this way can we be assured that actual wind integration costs is recovered. This adjustment reduces NPC by $1.88 million on an Idaho basis. I also recommend that the Commission adopt the premise of my secondary adjustment 2a OATT Wind Integrations Costs, so that the Company not be allowed to recover wholesale wheeling customer wind integration costs from retail customers through the ECAM.

Q. DO YOU HAVE A SECONDARY RECOMMENDATION?

A. Yes. If the Commission rejects my recommendation for this adjustment I recommend that the Commission accept my secondary proposed adjustments 2a OATT Wind Integration Costs and 2b. Balancing Wind Integration Costs, which are discussed in my following testimony.

Adjustment 2a. <u>OPEN ACCESS TRANSMISSION TARIFF (OATT) - WIND INTEGRATION</u>

Q. DOES THE COMPANY'S OATT TARIFF INCLUDE A CHARGE FOR WIND INTEGRATION EXPENSES FOR WHOLESALE TRANSMISSION CUSTOMERS?

A. No. Despite being aware of wind integration expenses for over six years, based on the inclusion of such expenses in its 2004 IRP, the Company has not made a filing with the Federal Energy Regulatory Commission requesting inclusion of such expenses in its OATT. So, the Company is attempting to recover these costs from retail customers.

Q. SHOULD RETAIL CUSTOMERS BE REQUIRED TO PAY FOR THESE COSTS?

A. Of course not. Recovery of these costs from OATT customers is the Company's responsibility and they have had over six years to make a filing with FERC that would allow them to recover such costs. Retail customers should not be burdened with these costs due to the Company's failure to make such a filing.

Q. HAS THE COMPANY INDICATED IF AND WHEN THEY PLAN TO MAKE A FILING TO MODIFY ITS OATT TO INCLUDE CHARGES FOR WIND INTEGRATION SERVICES TO NON-OWNED WIND FACILITIES?

A. Yes. In the stipulation for Oregon Docket UE 216 the Company agreed to make a filing before the Federal Energy Regulatory Commission in June 2011. While the Company has finally decided to make this filing there is nothing that prevented them from making the filing at a much earlier date.

Q. ARE WIND INTEGRATION COSTS INCLUDED IN OTHER TRANSMISSION PROVIDERS OATT?

A. Yes. As a matter of fact, the Company pays Bonneville Power Administration (BPA) for wind integration costs associated with the Goodnoe and Leaning Juniper wind projects and has included those costs in the wheeling expense.

Q. HAS FERC PREVIOUSLY ADDRESSED MODIFICATION OF THE OATT?

A. Yes. In Docket No. ER09-1314-0000, the FERC ruled that applicant, Northwestern Energy's proposal related to this issue was not superior to its proforma OATT tariff. The FERC stated that:

> Rather than proposing a generator regulation charge to recover capacity costs of holding additional reserves necessary to meet generator imbalances, NorthWestern's proposal seeks to eliminate any obligation under its Tariff to offer such service in the first instance (at least with respect to intermittent renewable generators exporting energy out of Northwestern's balancing authority area). Accordingly, we find that Northwestern's proposal is neither consistent with nor superior to the proforma Tariff. Our determination is without prejudice to Northwestern proposing to remedy the cost allocation issues discussed in this proceeding, consistent with the guidance set forth above.

Order Rejecting Proposed Tariff Revisions, FERC Docket No. ER09-1314-0000, Order No. 20091110 at paragraph 27 (November 10, 2009). The FERC also stated:

> In its filing, NorthWestern describes a "gap" between its obligations as a balancing authority and its opportunity to recover the costs associated with these obligations under its Tariff. NorthWestern asserts that its Tariff does not contain a mechanism that allows it to recover generator regulation service costs associated with transmission used to export energy from NorthWestern's system, which NorthWestern must incur to meet reliability standards. Moreover, Northwestern contends that its native load customers should not be required to subsidize the costs of providing generator regulation service to those generators that export energy from NorthWestern's system. To the extent that NorthWestern is not currently recovering the costs of providing generator regulation service to exporting generators, we agree that a mechanism allowing it to recover those costs is appropriate.

FERC clearly does not believe that retail customers should pay for the costs of wholesale customers either and suggested a mechanism should be allowed to solve the problem. In the interim, retail customers should not be required to pay for these costs. Accordingly, I recommend that such wind integration costs be excluded from NPC because the Company has had ample opportunity to request modification of its OATT to recover these costs from the parties that caused the Company to incur these expenses and retail customers should not be burdened for the Company's failure to act. This adjustment reduces NPC by $0.35 million on an Idaho basis.

Adjustment 2b. **WIND INTEGRATION COSTS - BALANCING**

Q. PLEASE EXPLAIN THE COMPONENTS OF THE WIND INTEGRATION COSTS.

A. The wind integration cost is comprised of Inter-hour and Intra-hour costs. Inter-hour cost is the balancing component and consists of pre-scheduling and hour-ahead balancing.

Intra-hour costs are the costs carrying load following and regulation reserves for the variability of wind generation. This adjustment focuses on the balancing component.

Q PLEASE EXPLAIN HOW THE COMPANY BALANCES ITS SYSTEM FOR WIND INTEGRATION.

A. The Company has a variety of options for balancing. In order of most frequent use balancing is accomplished through hourly firm wholesale transactions, re-dispatch of wholesale contracts with hourly flexibility, re-dispatch of generation resources, hourly non-firm wholesale sales transactions and wind curtailment.

Q. DOES THE COMPANY'S FILING INCLUDE A DOUBLE COUNT OF WIND INTEGRATION BALANCING COSTS?

A. Yes. The balancing cost component of wind integration is double counted because the Company's filing included actual short-term firm transactions for the period January 1, 2010 through May 4, 2010, which includes actual hourly firm wholesale transactions used for wind integration balancing and the Company's separately calculated wind integration costs using the $6.50 per MWH wind integration rate. This leaves the question of how to allocate part of the $6.50 per MWh rate to balancing to determine the amount of the double count.

Q. HOW SHOULD A PORTION OF THE $6.50 MWH RATE BE ALLOCATED TO BALANCING?

A. The method should be straight forward and based on Company data. With that clarification I believe we should look to the Company's last completed IRP to determine an allocation. In that IRP the Company calculated a total wind integration cost of $6.92 per MWH consisting of $2.09 per MWh for balancing and $4.83 for intra-hour integration. Using this information the balancing component for the $6.50 per MWh rate can be calculated by dividing $2.09 per MWh by $6.92 per MWh and multiplying that result (30.2%) times $6.50 per MWh. This produces a double count of $1.96 per MWh.

Q. SHOULD THE $1.96 BE REDUCED FURTHER TO COMPENSATE FOR THE PORTION OF BALANCING THAT IS ACCOMPLISHED BY MEANS OTHER THAN HOURLY FIRM WHOLESALE SALES TRANSACTIONS INCLUDED IN GRID?

A. A further adjustment could be reasonable if the information were available. However, the Company stated that there is no official Company estimate of how much balancing is accomplished through the various means identified above other than to place them in an order of most to least. Since the Company has previously stated that most of its balancing occurs through actual hourly wholesale sales transactions, which are included in GRID, $1.96 per MWh should be used to remove the double count. This adjustment reduces NPC by $0.14 million on an Idaho basis.

Adjustment 3. <u>**NON-FIRM TRANSMISSION**</u>

Q. DO YOU AGREE WITH PACIFICORP'S EXCLUSION OF NON-FIRM TRANSMISSION FROM NPC?

A. No. Exclusion of non-firm transmission is not consistent with actual operations and does not provide a match between costs and benefits. If the Company used an immaterial amount of non-firm transmission it may be reasonable to exclude it from normalized results. However, that is not the case. As shown below in Table 2 – PacifiCorp Transmission Utilization, a substantial amount of non-firm transmission is utilized. During 2009, non-firm transmission of energy exceeded STF transmission by over 2.69 million MWh or by more than 6 times. It is rather obvious that non-firm transmission is normally relied upon to balance and optimize the Company's system.

Table 2

Pacificorp Transmission Utilization
Millions MWh /1

	Non-Firm	STF	Total
2006	1.76	2.86	4.62
2007	0.88	3.66	4.53
2008	9.74	4.09	13.83
2009	3.13	0.44	3.57
4 Year Avg.	3.88	2.76	6.64

/1 Excludes Cal ISO, intra bubble and transmission already modeled

Q. **WHY DOES THE COMPANY UTILIZE NON-FIRMTRANSMISSION?**

A. Non-firm transmission is utilized to balance and optimize the Company's system. This keeps NPC lower than it would be absent use of non-firm transmission. Lower NPC is accomplished through more efficient use of generation and transmission assets in concert with wholesale transactions and creates more benefits (earnings) for the Company and its shareholders. Since these benefits are derived from assets and expenses already included in rates, non-firm transmission should be included in NPC to match costs with benefits.

Q. **HAS THE INCLUSION OF NON-FIRM TRANSMISSION BEEN ADOPTED BY OTHER COMMISSIONS OR BEEN AGREED TO BY THE COMPANY?**

A. Yes. Inclusion of non-firm transmission has been adopted in the Company's two largest jurisdictions, Utah and Oregon, The Utah Commission adopted non-firm transmission in Docket No. 07-035-93. More recently, in the stipulation for Oregon Docket UE-216, the Company agreed to include non-firm transmission links and costs in all future filings using a four-year average.

Q. WHAT IS YOUR RECOMMENDATION FOR NON-FIRM TRANSMISSION?

A. Non-firm transmission links and costs should be modeled in GRID using the same four-year average used to normalize thermal generation. This will match costs and benefits and thereby allow customers to receive the full benefits of the system they are paying for in rates. The adjustment reduces NPC by $0.14 million on an Idaho basis.

Adjustment 4. **<u>DUNLAP RESERVE REQUIREMENT</u>**

Q. PLEASE EXPLAIN THE DUNLAP RESERVE REQUIREMENT ADJUSTMENT.

A. The Company did not model the Dunlap wind project as having an operating reserve requirement. This adjustment includes the operating reserve requirement for Dunlap and increases NPC by $0.01 million on an Idaho basis.

Adjustment 5. **<u>RESERVE SHUTDOWNS</u>**

Q. PLEASE DEFINE RESERVE SHUTDOWNS.

A. Reserve shutdown is a state in which a thermal unit was available for service but not electrically connected to the grid for economic reasons.

Q. HOW ARE RESERVE SHUTDOWNS USED IN THE COMPANY'S CALCULATION OF FORCED OUTAGE RATE INPUTS FOR GRID?

A. The Company's forced outage rate calculation excludes reserve shutdown hours from the denominator. The formula is as follows:

> Forced outage rate = total lost hours / total possible hours less planned outages and reserve shutdowns

Total lost hours is the sum of forced deratings, forced outages, maintenance deratings, maintenance outages and planned deratings. Total possible hours is the sum of hours in the period multiplied by the each thermal plants maximum dependable capacity.

Q. DOES THE COMPANY'S RESERVE SHUTDOWN ADJUSTMENT COMPONENT OF THE FORCED OUTAGE RATE CALCULATION PRODUCE REASONABLE RESULTS?

A. No. The Company's forced outage rates are inconsistent with GRID's calculation of generation lost due to forced outages because of inconsistencies between the two calculations. In GRID forced outage rates are applied to the units' total possible generation <u>before</u> reserve shutdowns and after planned outages, while the Company's forced outage rates used as an input to GRID are calculated <u>after</u> reserve shutdowns and planned outages. Due to this difference, the Company's proposed forced outage rates produce too much lost generation when used as an input in GRID.

Q. WOULD ELIMINATION OF THE RESERVE SHUTDOWN ADJUSTMENT FROM THE DENOMINATOR OF THE COMPANY'S FORCED OUTAGE RATE CALCULATION MEAN THAT RESERVE SHUTDOWNS ARE EXCLUDED FROM NPC?

A. Not at all. The Company's daily screen modeling in GRID specifically identifies when CCCTs are available but are not economic to run and essentially places them on reserve shutdown so they cannot run. Therefore, reserve shutdowns would still be modeled in NPC.

Q. WHAT IS YOUR RECOMMENDATION FOR RESERVE SHUTDOWNS?

A. The Company's forced outage rate calculation is inconsistent with the GRID calculation of generation lost due to forced outages and consequently produces too much lost generation. To correct this problem the Company's forced outage rate calculation should be revised by removing the adjustment for reserve shutdowns. This adjustment reduces NPC by approximately $0.05 million on an Idaho basis.

Adjustment 6. **<u>TOP OF WORLD WIND IN SERVICE DATE</u>**

Q. PLEASE EXPLAIN THE TOP OF WORLD WIND ADJUSTMENT.

A. During discovery the Company informed Monsanto that the in-service date for this project was now expected to be October 1, 2010 instead of November 1, 2010. This adjustment moves the in-service date to October 1, 2010 and increases NPC by $0.09 million on an Idaho basis.

Adjustment 6a. **<u>TOP OF WORLD INCREMENTAL WIND INTEGRATION</u>**

Q. PLEASE EXPLAIN THIS ADJUSTMENT.

A. As I previously discussed in this testimony, my primary recommendation is to remove wind integration costs from the Company's filing so that they are recovered through the ECAM. If my primary recommendation is not adopted this adjustment will include the incremental wind integration costs associated with the one additional month that the Top of World wind project is expected to be in-service during 2010.

Adjustment 7. **<u>CAL ISO FEES</u>**

Q. DOES THE COMPANY'S FILING INCLUDE A FULL NORMALIZED YEAR OF CAL ISO WHEELING AND SERVICE FEES?

A. Yes. NPC includes $4.7 million of these fees on a total Company basis. However, as explained later in my testimony, a significant portion of these fees are not economic because there are no wholesale transactions that rely on the Cal ISO beyond May 3, 2010.

Q. WHY AND WHEN DOES PACIFICORP INCUR THESE FEES?

A. These fees are incurred when the Company uses the Cal ISO system to balance and optimize its system. In other words, the fees are incurred when PacifiCorp believes the associated wholesale transactions produce an incremental benefit above the fees. Some of the fees are related to the Company's strategy to hedge their long position at Four Corners. As explained in Mr. Duvall's testimony from Wyoming Docket No. 20000-341-EP-09:

> Sales at SP-15 are made to hedge the Company's long position at Four Corners. This occurs when the Company has a desire to hedge its fixed price exposure but the Four Corners Market is illiquid. A portion of these transactions are financial hedges and do not require physical delivery of power. However, if the hedges are physical products, at a time closer to delivery when the Four Corners market becomes more liquid, the Company would sell at Four Corners and buy at SP-15. Alternatively, the Company may wheel power from Four Corners to SP-15 to close the SP-15 physical positions in the hour-ahead market if transmission were available and it is more economical to do so.

Fees can also be incurred with other balancing and optimizing transactions with the Cal ISO.

Q. DOES THE COMPANY'S NPC INCLUDE ANY WHOLESALE TRANSACTIONS THAT COULD INCUR CAL ISO FEES AND PRODUCE A MATCHING BENEFIT?

A. Yes. The filing included actual STF transactions from January 1, 2010 through May 3, 2010. However, after May 3, 2010 the filing did not include any wholesale transactions with the CAL ISO.

Q. WHY DOESN'T THE FILING INCLUDE ANY WHOLESALE TRANSACTIONS THAT COULD INCUR CAL ISO FEES?

A. Historical records reveal that most of the transactions with the Cal ISO as a counter party are incurred shortly before or on the actual day of delivery. Due to the Company's use of a forecast test period and the fact that the filing was made many months prior to the end of the forecast test year, transactions that would incur Cal ISO wheeling and service fees had not occurred in most months at the time of filing. As a result, NPC includes a full year of Cal ISO costs, but only wholesale transactions that would generate the Cal ISO expense prior to May 4, 2010. For this reason, I recommend that all Cal ISO fees included in the filing for the period May 4, 2010 through December 31, 2010 be excluded from NPC. In addition, I recommend that actual Cal ISO fees be used for the period January 1, 2010 through May 3, 2010 to match with the actual wholesale transactions already included in the filing that caused the actual Cal ISO costs to be incurred. This adjustment reduces NPC by $0.20 million on an Idaho basis.

Adjustment 8. <u>COLSTRIP PLANNED OUTAGES</u>

Q. PLEASE EXPLAIN HOW THE COMPANY DEVELOPS THERMAL PLANNED OUTAGE SCHEDULE INPUTS FOR GRID.

A. The methodology employed by the Company to normalize planned outages uses 48-month average of historical data for the period 2006-2009 to determine the amount of time the plants are on outage. Historically, these outages are scheduled during the spring and fall shoulder months when market prices tend to be lower so that replacement power costs are kept low and ample energy is available from the marketplace to replace the generation on outage. After the Company develops the amount of time the units were on outage it develops a normalized outage schedule based on a variety of factors including market prices, historical outages and the amount of units or MW on outage at a given point in time.

Q. DO YOU AGREE WITH THE COMPANY'S NORMALIZED OUTAGE SCHEDULE INCLUDED IN GRID?

A. Not completely. The starting point of Colstrip 3 and Colstrip 4 planned outages should be moved from September to May to better optimize the timing of the outages so that NPC would be lower than it would be using the Company's outage schedule.

Q DOES YOUR PROPOSED CHANGE TO THE PLANNED OUTAGE SCHEDULE RESULT IN AN EXCESSIVE AMOUNT OF CAPACITY ON OUTAGE DURING MAY?

A. No. The amount of capacity on outage is within a reasonable range based on a comparison of actual planned outages compared to planned included in the Company's filing.

Q. WHAT IS YOU RECOMMENDATION?

A. I recommend that the Colstrip 3 planned outage be moved from September 18^{th} to May 1^{st} and the Colstrip 4 planned outage be moved from September 30^{th} to May 13^{th}. This adjustment reduces proposed NPC by $0.02 million on an Idaho basis.

Adjustment 9. **<u>ENERGY GATEWAY TRANSMISSION</u>**

Q. PLEASE EXPLAIN THE GATEWAY TRANSMISSION ADJUSTMENT.

A. This adjustment removes the transmission capacity upgrades associated with the Energy Gateway transmission project included in GRID as part of the adjustment to remove the Energy Gateway project from the Company's filing as recommended by Monsanto witness Dennis Peseau. This adjustment increases NPC by $0.20 million on an Idaho basis.

Adjustment 10. **<u>CHOLLA 4 CAPACITY</u>**

Q. PLEASE EXPLAIN HOW CHOLLA 4 CAPACITY WAS MODELED.

A. The Company modeled Cholla 4 capacity at 387MW even though the capacity was upgraded to 395MW not long ago. It appears the reasoning behind modeling the capacity at 387MW is because the Company has 387 MW of firm transmission rights to move Cholla 4 Generation.

Q. DO YOU AGREE WITH MODELING CHOLLA 4 AT 387MW?

A. No. Cholla is already derated below 387 MW for weekday and week-end forced outage rates of 5.24% and 7.04%, which respectively produce a derated capacity of 374.3 MW and 367.2 MW for Cholla 4. Since the derated capacity is already below the 387 MW of firm transmission rights it is not necessary to derate the plant for firm transmission rights. Cholla 4 capacity should be modeled at the full 395MW. This adjustment reduces NPC by $0.07 million on an Idaho basis.

Adjustment 11. **<u>MORGAN STANLEY CALL PREMIUMS</u>**

Q. PLEASE DESCRIBE THE TWO MORGAN STANLEY CALL OPTION CONTRACTS INCLUDED IN THE COMPANY'S FILING.

A. The Company entered two call option contracts with Morgan Stanley during November 2005 for the period June 1, 2010 through August 31, 2010. Each contract provides the right to call [redacted] of firm super-peak product per hour, exercisable only on the "WECC Pre-Scheduling Day" at an additional cost of [redacted] per MWh for one contract and [redacted] per MWh for the second contract. For this right the Company paid a premium of [redacted] for one contract and [redacted] for the second contract.

Q. WERE EITHER OF THESE CALL CONTRACTS EXERCISED IN THE COMPANY'S FILING?

A. No. Neither contract was dispatched because they were not economic for the test year.

Q. HAS THE COMPANY PREVIOUSLY STATED A POSITION ON THE INCLUSION OF CALL OPTION CONTRACTS THAT ARE NOT ECONOMIC?

A. Yes. In Oregon Docket UE-191 the Company stated that call option contracts should be removed from NPC if removal lowers NPC. In this case removal of both Morgan Stanley call option contracts lower NPC. For this reason, I recommend removal of Morgan Stanley call option contracts p272153-6 and p272154-7. This adjustment lowers NPC by $0.17 million on an Idaho basis.

Adjustment 12. **<u>BEAR RIVER HYDRO NORMALIZATION</u>**

Q. PLEASE EXPLAIN HOW THE COMPANY HISTORICALLY NORMALIZED HYDRO GENERATION FOR SMALL HYDRO PROJECTS LIKE BEAR RIVER.

A. Small hydro projects generally have no appreciable storage and are operated as run of river projects where stream flow in is equal to the stream flow out. For these small projects, normalized generation is based on an evaluation of 30 years of historical generation capability. Bear River is somewhat different in that it does have some storage capability.

Q. HOW DOES THE 30-YEAR NORMALIZATION PROCESS WORK?

A. Thirty years of historical generation are used to develop a median hydro forecast. When a new year of data becomes available it becomes the first year data and the prior first year data becomes the second year data and so forth until the prior 29th year data becomes the 30th year data and the prior 30th year data is excluded. This provides customers and the Company with a balanced recovery of generation benefits over the 30-year period.

Q. HAS THE COMPANY'S BEAR RIVER NORMALIZATION DEVIATED FROM THE 30-YEAR NORMALIZATION METHOD IN RECENT YEARS?

A. Yes. The Company's calculation of normalized hydro generation for Bear River began to exclude flood control years from the 30 year historical record starting in 2008. In response to WIEC Data Request 8.24 in Docket No. 20000-333-ER-08, the Company explained how they adjusted Bear River generation and explained their reasons for the adjustments:

> The inflow forecast for Bear River was recently reduced. Years in which surplus water was released from Bear Lake ("flood control years") were removed from the historical data set from which the Bear River generation forecast is derived. Flood control years provide additional water for Bear River generation. However, the region is currently impacted by long-term drought conditions and based on the low water level in Bear Lake the probability of a flood control year is minimal for the next three years.

Q. DO THE DROUGHT CONDITIONS PROVIDE A LEGITIMATE BASIS FOR EXCLUDING FLOOD CONTROL YEARS FROM THE CALCULATION OF NORMALIZED GENERATION?

A. No. Arbitrarily removing flood control water year data from the historical record because drought conditions are expected to persist is not consistent with the 30-Year normalization methodology employed by the Company for other small projects or the methodology employed for other larger projects. The Bear River methodology is clearly a case of cherry picking, which produces higher NPC because it excludes the nine highest generation years from the thirty-year normalization period. Those nine years have a median annual generation of 563,114 MWh. In contrast, the years included in the Company's filing have a median generation forecast of 205,576 MWh. Put another way, the Company's Bear River generation normalization transfers customer's benefits of higher hydro generation to shareholders.

Q. IS THE BEAR RIVER ADJUSTMENT SYMMETRICAL FROM THE PERSPECTIVE OF PREVIOUS HYDRO ADJUSTMENTS OR FILINGS?

A. No. To the best of my knowledge, the Company has never volunteered adjustments to increase hydro generation and decrease NPC based on an expectation of a good water year. For the reasons explained above, I recommend that the Company's Bear River normalization should be revised to use the same 30-year normalization methodology used for other small hydro facilities. My recommendation reduces NPC by approximately $0.13 million on an Idaho basis.

Adjustment 13. **BLACK HILLS SHAPING**

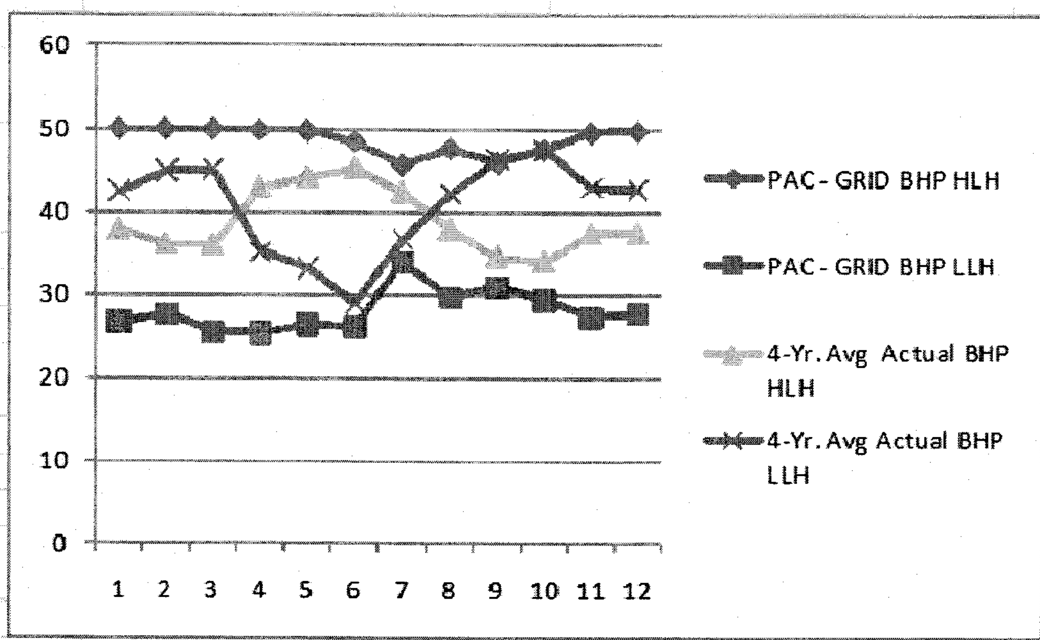
Q. PLEASE EXPLAIN THE COMPANY'S MODELING FOR THE BLACKHILLS WHOLESALE SALES CONTRACT.

A. The contract is classified as a call option contract in GRID and the contract terms for energy such as hourly, daily weekly, monthly and annual take and delivery points are inputs to GRID. Based on this information and the Company's forward price curve GRID dispatches the contract during the highest cost hours based on the assumption that is what the purchasing entity would do.

Q. DO YOU AGREE WITH THIS ASSUMPTION?

A. No. While the assumption may be reasonable for some contracts it really depends on the requirements and assumptions of the purchasing entity. In the case of Black Hills, the actual delivery shape of the sale is much flatter than it is modeled in GRID. As shown below in Graph 1, Black Hills Dispatch, the difference between actual on and off-peak deliveries is smaller (flatter) than the difference between the Company's modeled on and off-peak deliveries.

Graph 1 – Black Hills Dispatch



Q. ARE YOU SURPRISED BY THE SHAPING DIFFERENCE?

A. No. The difference is not surprising because the Company simply does not know what Black Hills system requirements and assumptions are. In this case, the assumption that Black Hills would do exactly what the Company thinks they would do is incorrect and results in a higher contract cost in GRID than occurs on an actual basis. To correct this problem the energy shape should be modeled using the actual delivery shape.

Q. DOES THE COMPANY USE ANY ACTUAL INFORMATION TO MODEL OTHER ASPECTS OF THE BLACKHILLS CONTRACT?

A. Yes. The delivery points for the contract are modeled based on actual information. The purpose of using actual delivery points is to capture the expected cost of the sale because the energy can be delivered on both the east and west side of the Company's system. This fact also suggests that the energy shape should use actual information.

Q. DOES THE COMPANY USE ACTUAL INFORMATION TO MODEL OTHER CONTRACTS?

A. Yes. Actual information is also used to model other contracts. For example, energy for the Gem State contract is modeled for the months of May, June, July and August based on historical information despite the fact that the contract states that deliveries are expected to occur during June, July and August. The Company also uses actual data for various inputs of other contracts and GRID inputs such GP Camas, APS, Biomass and forced and planned outages etc.

Q. WHAT IS YOUR RECOMMENDATION?

A. The Black Hills wholesale sales contract should be modeled based on a four a four-year average of historical dispatch information. This adjustment reduces NPC by $0.08 million on an Idaho basis.

Adjustment 14. **<u>MONA MARKET</u>**

Q. PLEASE EXPLAIN HOW PACIFICORP SIZED THE MONA WHOLESALE MARKET HUB?

A. The Company modeled the market capacity as no graveyard market (the five hours ended 1:00 AM through 6:00AM Pacific time) and 75 MW in all other hours.

Q. DOES THE MONA WHOLESALE SALES MARKET CONSIST SOLELY OF SALES WITH A MONA POINT OF DELIVERY (POD) DESIGNATION?

A. No. According to Confidential Attachment Monsanto 2.15, the Mona market consists of Mona, Gonder, Red Butte, Sierra Pacific system (SPPC) and Nevada Utah Border (NUB) PODs.

Q. GIVEN THIS INFORMATION, HAS PACIFICORP ADEQUATELY SIZED THE MONA MARKET?

A. No. As shown below in Table 3, the Company's Mona market capacity is considerably understated based on a comparison wholesale sales volume for the 48-month period ended December 31, 2009.

Table 3
Mona Market Size Compaison
Average Megawatts

	PacifiCorp All Other Hours	PacifiCorp Graveyard	Actual 48-Month Avg. All Other Hours	Actual 48-Month Avg. Graveyard
January	/1	0	/1	27
February	/1	0	/1	24
March	/1	0	/1	20
April	/1	0	/1	15
May	75	0	75	17
June	75	0	183	21
July	75	0	229	26
August	75	0	296	44
Septembei	75	0	240	36
October	75	0	151	25
November	75	0	132	24
December	75	0	167	17

/1 Not applicable because filing uses actual 2010 data

Q. WHY DID YOU USE A 48-MONTH AVERAGE FOR THE COMPARISON SHOWN IN TABLE 3?

A. I used a 48-month average to be consistent with the Company's normalization of thermal generation, STF transmission capacity and graveyard market caps, which all use a 48-month normalization period.

Q. WHAT IS YOUR RECOMMENDATION FOR CURRING THE CONSIDERABLE UNDERSTATEMENT OF THE MONA MARKET?

A. The Mona market capacity needs to be sized appropriately to provide a proper match of costs and benefits. I recommend that the Mona market capacity be corrected by using the 48-month average capacities shown above in Table 3. This adjustment reduces NPC by approximately $0.03 million on an Idaho basis.

Adjustment 15. **<u>NAUGHTON 3 OUTAGE</u>**

Q. PLEASE EXPLAIN THE CAUSE OF THE NAUGHTON 3 OUTAGE WHICH STARTED MAY 8, 2009 AND ENDED MAY 26, 2009.

A. The Company's contractor Siemens failed to complete the Naughton 3 overhaul on schedule per contract terms due to poor performance. The major reasons for the failure to [redacted]

Q. DID THE COMPANY RECIEVE COMPENSATION FROM SIEMENS FOR FAILURE TO MEET CONTRACT TERMS?

A. Yes. Pursuant to the terms of the contract the Company received a $500,000 liquidated damages payment in June 2009 that was booked to FERC account 555 purchase power expense.

Q. DID IDAHO RETAIL CUSTOMERS RECEIVE AN ALLOCATED SHARE OF THE $500,000 PAYMENT?

A. No. The ECAM did not become effective until July 1, 2009.

Q. DO YOU AGREE WITH THE COMPANY'S INCLUSION OF THE OUTAGE EVENT IN NPC?

A. No. The outage was caused by poor performance of the Company's contractor (Siemens) and is therefore an imprudent outage that should not be included in the calculation of NPC. Furthermore, the Company has already been compensated for the outage pursuant to the terms of their contract through the $500,000 liquidated damage payment it received. Inclusion, of the outage in NPC would result in the Company collecting outage costs twice, once from customers and once from Siemens. For these reasons, I recommend that the outage be removed from the calculation of NPC. This adjustment reduces NPC by approximately $0.03 million on an Idaho basis.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.