Exhibit No.___(MCD-1T)
Docket Nos. UE-130043
Witness: Michael C. Deen

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP D/B/A PACIFIC POWER & LIGHT COMPANY, Respondent.	)	Docket Nos. UE-130043

RESPONSIVE TESTIMONY OF MICHAEL C. DEEN

ON BEHALF OF

BOISE WHITE PAPER, LLC

REDACTED VERSION

June 21, 2013

TABLE OF CONTENTS

INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael C. Deen, and my business address is 900 Washington Street, Suite 780, Vancouver, Washington 98660. I am employed by Regulatory and Cogeneration Services, Inc. ("RCS"), a utility rate and consulting firm.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I have been involved in the energy industry for approximately 7 years. During that time, I have served as an analyst and expert on a variety of power supply, cost, ratemaking, and policy topics—primarily regarding Pacific Northwest investor-owned utilities and the Bonneville Power Administration. I have provided testimony on behalf of the Industrial Customers of the Northwest Utilities ("ICNU") before the Oregon Public Utility Commission ("OPUC") in various proceedings regarding Portland General Electric Company and PacifiCorp (or, the "Company"). I have also provided testimony on behalf of ICNU before the Washington Utilities and Transportation Commission ("WUTC" or the "Commission") regarding Avista, PacifiCorp, and Puget Sound Energy. In addition, I have testified on natural gas matters regarding Northwest Natural before the OPUC and regarding Avista and Puget Sound Energy on behalf of the Northwest Industrial Gas Users before the WUTC. A further description of my educational background and work experience can be found in Exhibit No. __ (MCD-2).

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am testifying on behalf of Boise White Paper, LLC ("Boise"). Boise manufactures and distributes paper products in the United States, including sheet papers, containerboard and corrugated containers, newsprint grades, and market pulp. Boise is PacifiCorp's largest customer in Washington, purchasing both power and power delivery services at its mill in Wallula, Washington. Boise is a major employer in Southwestern Washington, and is a member of ICNU, a non-profit trade association of large industrial customers that has been a party to many proceedings before the Commission involving PacifiCorp and other Northwest utilities, including PacifiCorp's most recent general rate case (UE-111190).

Q. WHAT TOPICS WILL THIS TESTIMONY ADDRESS?

A. This testimony will address the Company's proposed net power costs ("NPC") and other revenue requirement adjustments, Boise's recommendations regarding the Company's proposed Power Cost Adjustment Mechanism ("PCAM"), and Boise's recommendations regarding the Company's rate spread proposal.

Q. PLEASE BRIEFLY SUMMARIZE YOUR RECOMMENDATION IN THIS PROCEEDING.

A. The Company filed for a revenue requirement increase of approximately $42.8 million, or a 14.1% average rate increase. My proposed adjustments would reduce this amount by approximately $23.7 million. The following table summarizes the effects of these adjustments. After the table, I provide a brief narrative description of each adjustment.

Table 1. Summary of Revenue Requirement Adjustments ($ Million)

ISSUE	WA Rev Req Impact
Changes to Accepted WCA Methodologies	**-$13.5**
WCA Allocation Factor Derivation:	-$0.8
Exclude OR and CA QF Resources:	-$11.2
Include ECA sale in NPC determination:	-$0.3
DC Intertie/NOB	-$1.1
Wind Shape	**-$1.0**
3rd Party Wind Integration Costs	**-$0.2**
Market Caps	**-$2.9**
Jim Bridger Heat Rate Improvements:	**-$0.6**
Jim Bridger Coal Cost	**-$5.1**
FERC OATT Settlement:	**-$0.3**
Total:	**-$23.7**

- **Changes to Accepted WCA Methodologies:** PacifiCorp is proposing a number of changes to Commission accepted methods for Western Control Area ("WCA") cost allocation and power cost modeling. These changes include modification of the WCA cost allocation factor for generation costs, inclusion of costs related to Qualifying Facilities ("QF") contracts sited in Oregon and California, exclusion of the imputed system sale to the PacifiCorp eastern system, and inclusion of costs related to PacifiCorp's rights to transmission on the DC Intertie. The combined effect of rejecting these modifications is approximately $13.5 million, Washington basis.

- **Wind Energy Forecast:** The Company is proposing to modify its wind energy forecast from its historical practice of a "P50," or median forecast, to a forecast based on 48 months of actual generation data. Given the potential for inter-annual variability of wind generation, this change is inappropriate for normalized rate making. Reverting to PacifiCorp's historic forecasting methods would reduce the Washington revenue requirement by approximately $1.0 million.

- **<u>Third Party Wind Integration Costs:</u>** The Company is proposing to include the costs of integrating non-owned, third party wind facilities in its balancing authority without fully including offsetting benefits. The effect of removing these costs is to reduce the Washington revenue requirement by approximately $0.2 million.

- **<u>Sales Limits or Caps:</u>** The Company places limits or "caps" on the potential market sales in the GRID model in each individual hour in the rate year, based on the average energy sold over the entire monthly peak or off-peak period for the Company's most recent 48 months of actual sales. These constraints are an artificial modeling construct that prevents GRID from achieving anywhere close to the average annual sales from the 48 month historical period. There is also no economic or rational justification for the caps and, as such, they should be eliminated. The isolated effect of this adjustment is to lower the Washington revenue requirement by $2.9 million.

- **<u>Jim Bridger Heat Rates:</u>** The Company has made a significant capital investment to upgrade to the functionality of Jim Bridger Unit 2. Although the Company has reflected the increased generation capacity as a result of this upgrade, it has not included the increased efficiency of the unit. Correcting this issue and an error in the Company's heat rate derivations reduces the Washington revenue requirement by approximately $0.6 million.

- **<u>Jim Bridger Coal Costs:</u>** Consumers should receive the benefit of "lesser of" cost or market pricing for transactions with utility affiliate suppliers. Moving the price of the Jim Bridger plant coal supply to a market price reduces the Washington revenue requirement by approximately $5.1 million.

- **<u>OATT Revenues:</u>** The Company should include the results of the recent settlement of its Open Access Transmission Tariff ("OATT") filing before the Federal Energy Regulatory Commission ("FERC"). This adjustment would lower the Washington revenue requirement by approximately $0.3 million.

- **<u>PCAM:</u>** The Commission should reject PacifiCorp's proposed PCAM, which completely ignores and contradicts the Commission's direction to the Company regarding PCAM structure. In the event the Commission wishes to permit a PCAM for Pacificorp in this proceeding, I recommend a structure similar to that recently approved by the Oregon PUC in the Company's Docket No. UE 246 general rate case ("GRC") from 2012.

- **<u>Rate Spread:</u>** Boise recommends an alternative rate spread based on the Company's cost of service study and Commission precedent regarding rate spread. Specifically, I recommend below average increases for street lighting and irrigation schedules, and an equal increase to all other classes.

Q. DOES BOISE HAVE ANY ADDITIONAL RECOMMENDATIONS?

A. Yes. As fully explained in the testimony of Boise witness Michael P. Gorman, PacifiCorp's cost of capital and capital structure should be lowered to accurately reflect the Company's cost of capital. Mr. Gorman's recommendations will lower the revenue requirement by an additional $8.3 million. Cumulatively, Boise recommends a downward adjustment of approximately $32.0 million to the Company's filed case.

REVENUE REQUIREMENT ISSUES

Changes to Accepted WCA Methodologies

Q. HAS PACIFICORP PROPOSED SUBSTANTIAL CHANGES TO THE WAY IN WHICH IT IMPLEMENTS THE WCA METHODOLOGY?

A. Yes. PacifiCorp has made a number of changes from previous Commission-approved methods for implementing the WCA methodology. Four of these changes inappropriately conflict with Commission precedent, and I recommend the changes be disallowed.

First, as described on page 27 of Exhibit No. ___(SRM-1T), the Company is proposing to change the calculation of the Control Area Generation West ("CAGW") allocation factor which affects the level of generation costs allocated to Washington under the WCA. In the Company's revised response to Boise Data Request 3.3, the Company stated that the revenue requirement impact of this proposed change is approximately $0.8 million. This data response is attached as Exhibit No. ___(MCD-3).

Second, as described on pages 5-7 of Exhibit No. ___(GND-1CT), PacifiCorp is proposing to include the costs of QF contracts located in California and Oregon in the calculation of its NPC for 2014. The revenue requirement impact of this proposed change is an increase of approximately $11.2 million relative to the currently approved Commission method of including only Washington QF contracts. The Commission should reject this change to its methodology.

Third, as described on page 9 of Exhibit No. ___(GND-1CT), the Company is proposing to exclude the imputed value of the sale from PACW to PACE that it has historically modeled as part of its NPC. The revenue requirement impact of this modeling change is an increase of approximately $0.3 million.

Finally, the Company is proposing to include the costs of the Company's transmission rights related to the DC intertie as described on pages 20 to 21 of Exhibit No. ___(GND-1CT). The Commission previously disallowed the costs of this transmission asset in PacifiCorp's 2010 rate case. The effect of including this transmission right and associated modeled purchases at the Nevada-Oregon Border market in GRID in this case is to increase the Washington revenue requirement by approximately $1.1 million.

The combined effect of these four changes is to increase the Washington revenue requirement by approximately $13.5 million.

Q. WHY ARE QF CONTRACTS CURRENTLY SITUS ASSIGNED?

A. For various reasons, QF contract pricing and terms under PURPA are handled differently in the different jurisdictions in which PacifiCorp operates. For example, Oregon and Idaho have implemented fixed price standard offers while Washington does not have such a system. So as not to expose Washington consumers to potential harm from QF pricing policies in other states, the WCA was adopted with QF resources being situs assigned to each state.

Q. WHY IS THIS METHODOLOGY APPROPRIATE?

A. As described above, this methodology prevents Washington consumers from being harmed by QF contract policies over which they can exercise no control. The practical effect of this policy is to replace Oregon and California QF resources in GRID with market purchases. As market prices can be considered as a proxy for avoided costs, this is a reasonable approach to modeling the level of NPC needed to serve Washington loads. Washington customers should not bear elevated costs created by the decisions of other state Commissions, and the Commission should decline to change its current methodology.

Q. DID THE COMPANY AND INTERESTED PARTIES RECENTLY ENGAGE IN A COLLABORATIVE PROCESS TO INVESTIGATE POTENTIAL CHANGES TO THE WCA METHODOLOGY?

A. Yes. My understanding is that the parties did engage in such a process, which concluded in October 2012.

Q. WHERE ANY OF THE PROPOSED CHANGES TO THE WCA METHODOLOGY YOU HAVE IDENTIFIED ABOVE AGREED TO BY PARTIES AS PART OF THAT PROCESS?

A. My understanding is that none of the four changes to the WCA identified above were agreed to by parties or approved by the Commission as part of the collaborative process.

Q. ARE THERE OTHER ONGOING PROCESSES THAT ARE EVALUATING THE APPROPRIATE INTERJURIDICTIONAL METHODS FOR ALLOCATING THE COSTS OF PACIFICORP'S SYSTEM?

A. Yes. PacifiCorp and interested parties from the jurisdictions of Oregon, Idaho, Wyoming and Utah are currently participating in the Multi-State Process ("MSP") to evaluate the appropriate allocation of PacifiCorp's system costs between the various state jurisdictions going forward. The MSP is still in its early stages, but as it progresses it will likely provide information that could allow the Commission to evaluate appropriate changes to the WCA or adopt a new allocation method entirely.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE WCA IN THIS PROCEEDING?

A. I recommend that the Commission reject PacifiCorp's modeling changes related to the WCA allocation factor, Oregon and California QF contracts, the imputed PACE sale, and cost related to the DC Intertie and NOB purchases. None of these changes were agreed to as part of the recent WCA collaborative process. Given the failure of the WCA collaborative process to produce consensus for changes to the WCA methodology and the early stage of the MSP process, I recommend that for this proceeding the Commission maintain the current WCA methods, which adequately model the Company's cost of service in Washington. Further, PacifiCorp has not justified these one-sided changes to the WCA, which inappropriately assign more system costs to Washington customers.

Wind Energy Forecast

Q. HAS THE COMPANY PROPOSED CHANGES TO ITS WIND ENERGY FORECAST IN THIS PROCEEDING?

A. Yes. In past cases, expected annual wind generation in the GRID model was based on a "P50" forecast. The P50 forecast projected generation at a level that is expected to have an equal probability of either being higher or lower than forecast in the rate year (i.e., a median forecast). In this case the Company is proposing to use the average of 48 months of actual generation data to calculate normalized generation levels. In instances when the Company does not have 48 months of actual generation data, it is filling in missing data with the P50 forecast.

Q. IS THIS MODELING CHANGE APPROPRIATE?

A. No. Wind generation exhibits a significant degree of inter-annual variability in output, and four years of actual data is far too short a time for use in normalized ratemaking.

Forecasting normalized annual generation for large-scale wind projects in the United States is very much a science still in development. However, it is clear that wind power resources can display a high level of variability in inter-annual generation. For example, a recent technical report titled "Long-Term Wind Power Variability" published by the National Renewable Energy Laboratory ("NREL"), a national lab of the Department of Energy, concluded that the variation in production at wind power plants between years was most comparable to run-of-river hydro. The conclusion of the report states as follows regarding the wind power plants ("WPP") studied:

> The wind power data from WPPs in different parts of the country suggest that one can expect relatively large inter-annual changes. The climate and regional weather pattern are the driving forces behind wind and wind plant outputs. Changes in climate and weather patterns will be reflected in the longer-term performance of WPPs. In this respect, wind power is similar to hydropower, especially run-of-the-river type, in that there are high energy production (wet) years and low energy production (dry) years. The available data show that during the highest production year, total wind energy from the same WPP can be almost 40% higher than the annual production of the lowest production year. The available data do not appear to be enough to establish a long-term pattern or trend.[1/]

In other words, only a few years of data is inadequate to conclude that the planning basis on which the plant investment was determined prudent (P50) should be abandoned for ratemaking purposes at the expense of customers. For normalized hydro forecasting, it

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[1/] Long-Term Wind Power Variability. Y. H. Wan. Technical Report, NREL/TP-5500-53637. Retrieved online at http://www.nrel.gov/docs/fy12osti/53637.pdf has been my experience that use of average generation over 20 or 30 years is common, though even longer periods are often utilized.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE MODELING OF EXPECTED WIND GENERATION IN GRID FOR THIS PROCEEDING?

A. The Company's use of 48-month averages should be rejected and the Company should revert to the P50 forecast method that has been previously accepted by the Commission. Given the potential for inter-annual variability at wind projects, I would not recommend using actual values to set the forecast without at least 10 years of actual data.

Q. WHAT IS THE EFFECT OF USING THE PREVIOUSLY ACCEPTED P50 FORECAST FOR WIND GENERATION IN THIS PROCEEDING?

A. Use of the previously approved median forecast reduced the Washington revenue requirement in this case by approximately $1.0 million.

Third Party Wind Integration Costs

Q. HAS THE COMPANY INCLUDED COSTS OF WIND INTEGRATION FOR THIRD PARTY WIND PROJECTS LOCATED IN ITS BALANCING AUTHORITY?

A. Yes, it has, despite the fact that the Commission rejected the inclusion of these costs as part of the Company's 2010 general rate case, as admitted in Exhibit No. ___(GND-1CT), page 22, lines 8-10 of the Company's own testimony.

Q. HAS THE COMPANY INCLUDED ALL OFFSETTING REVENUES THAT ARE RELATED TO COSTS OF PROVIDING WIND INTEGRATION SERVICES TO THIRD PARTIES?

A. No. The Company has not included a forecast of revenues from Schedule 3A of its OATT.

Q. SHOULD THE COMPANY BE PERMITTED TO RECOVER COSTS OF THIRD PARTY WIND INTEGRATION WITHOUT ALSO INCLUDING ALL OFFSETTING BENEFITS?

A. No. This is a basic violation of the matching principle. If the Company wishes to include costs of integrating third party wind resources, it must include all revenues it receives as a result of those operations, which includes revenues associated with its recently settled OATT filing before FERC.

Q. WHAT IS YOUR RECOMMENDATION REGARDING WIND INTEGRATION COSTS FOR THIRD PARTY RESOURCES IN THIS PROCEEDING?

A. I recommend that PacifiCorp's costs of integrating non-owned wind facilities be excluded from this case unless PacifiCorp also includes the full OATT revenues expected from integrating those resources. Excluding these costs reduces the Washington revenue requirement by approximately $0.2 million.

GRID Market Caps

Q. WHAT RESTRICTIONS HAS PACIFICORP PLACED ON MARKET SALES TRANSACTIONS IN THE GRID MODEL?

A. PacifiCorp has imposed hourly on-peak and off-peak caps on sales made in the GRID model for each month (although there is no corresponding cap on purchases). These hourly limits cap the amount of power that can be sold at each hub.

Q. HOW ARE THE CAPS DETERMINED?

A. The caps are derived from averaging the historical sales levels actually achieved by the Company over the 48-month period of July 2008 through June 2012. Given this method of averaging, there were many hours in the historical period when the actual sales exceeded the average sales value for a particular time interval. Accordingly, the caps can act as a constraint on sales transactions simulated in the GRID model.

Q. HAVE YOU ANALYZED THE EFFECT OF THE COMPANY'S CAPS ON THE NET POWER COSTS?

A. Yes. For the 48 month historical period, the Company achieved average annual sales at the COB and Mid-C hubs of approximately [redacted] megawatt hours ("MWh") or [redacted] average megawatts ("aMW"). In the Company's GRID simulation of NPC for 2014, total sales at COB and Mid-C are only [redacted] MWh or [redacted] aMW. GRID simulated sales with the removal of the market caps are approximately [redacted] MWh or [redacted] aMW. This shows that even with the removal of the caps, the GRID sales in total do not come close to achieving the total historical sales level and are inappropriate relative to the Company's historic levels of sales activity.

Further, while the Company argues that its sales ability is limited by the average energy it has sold over all hours (including hours when no transactions were executed), a far more meaningful cap value would be based on the actual maximum hourly value it has transacted at each hub. Diluting these maximum values by averaging in hours when minimal or no transactions at all may have occurred simply restricts the sales amount below the levels that the Company has achieved historically. This is because the market caps ignore the size of actual hourly transactions the Company has executed at each hub. The Company's method is inappropriate, as it results in cap values that are substantially lower than the actual transactions it has executed during the historical period and restricts sales when the Company has marketable capacity available to sell. This type of sales cap restriction is not employed by any other Northwest utility, including Puget Sound Energy and Avista. For all the foregoing reasons, I recommend that these caps be removed to more properly determine the projected NPC for the rate year.

Q. CAN YOU PROVIDE AN EXAMPLE TO FURTHER ILLUSTRATE THESE POINTS?

A. Yes. A simplified example can be useful to illustrate the flaws in the Company's proposed cap methodology. Suppose over a historical period, the Company was able to sell 50 MW of surplus power in half of the possible hours. In this case, the Company would have average sales of 25 MW of energy in each hour of the historical period, and 25 MW would be the resulting hourly cap in the GRID model. This would prohibit the model from making 50 MW sales in a manner consistent with the Company's historical operations. Even if GRID happened to perfectly replicate the historical sales opportunities, the market caps would result in the GRID model assuming PacifiCorp makes sales of 25 MW in half the hours and 0 MW in half the hours. This type of restriction is unrealistic and not economically supportable. The goal of power supply modeling should be to represent the operations of the Company as accurately as possible to achieve an appropriate projection of rate year costs. The Company's proposed market caps interfere with this goal.

Q. DOES REMOVAL OF THE MARKET CAPS SIGNIFICANTLY CHANGE THE AVERAGE PRICE THAT GRID SIMULATES FOR SYSTEM SALES?

A. No. Under the Company's market cap approach, the average price received for system sales is [redacted] per MWh. With no market caps, the average price received for system sales is a slightly lower value of [redacted] per MWh. This shows that removal of the market caps does not result in GRID simulating an unreasonable change in the price at which system sales are made.

Q. ARE YOU AWARE OF ANY CONCERNS THAT THE COMPANY MIGHT RAISE WITH REMOVING THE SALES CAPS FROM THE GRID SIMULATION?

A. In addition to the PacifiCorp arguments I just addressed, the Company may have concerns regarding the market liquidity at the hubs, potential for resulting increases in simulated coal generation, and double counting of transactions that are accounted for under the Company's trading margin adjustment.

Q. PLEASE RESPOND TO THE POTENTIAL MARKET LIQUIDITY CONCERN.

A. Boise has compiled Confidential Exhibit No. __(MCD-4C) to address potential market liquidity concerns at the Mid-C and COB trading hubs. The exhibit shows the Company's transactions by quarter for the years 2008, 2009, 2010, and 2011. This exhibit was compiled from a Platts Megawatt Daily report that used FERC Electric Quarterly Reports ("EQRs") which must be submitted to FERC indicating all sales activity. This exhibit demonstrates that, for the Mid-C and COB hubs, PacifiCorp's trading activity represents a small percentage of the total market activity. Therefore, any concerns regarding liquidity are unfounded.

PacifiCorp may also argue that without the caps, GRID allows for unlimited sales. As discussed previously, if this is really the concern, then a much more appropriate cap would be maximum hourly sales levels from the historical period rather than the Company's average energy method. However, in any case, although the GRID model may theoretically allow "unlimited" sales without the cap, this is not the case from a practical perspective. Without the artificial caps, the sales levels are still constrained by the amount of energy that the Company's resources are able to economically produce, as well as the Company's wheeling limitations. To the extent that GRID is able to more efficiently balance the system on an hourly basis through the use of balancing sales, this should not be cut off artificially. As I have demonstrated, the unconstrained sales level is reasonable because it is both below the Company's historical levels of sales activity and also represents a small portion of the overall activity at the markets in question.

Q. PLEASE RESPOND TO THE POTENTIAL CONCERN OF INCREASED COAL GENERATION.

A. Confidential Exhibit No. __(MCD-5C) compares the level of dispatched coal generation in the GRID simulation both with and without the market caps, as well as historical generation provided by PacifiCorp in response to Boise Data Request 1.6. The increase in coal generation with the elimination of the caps is only [redacted] Further, the uncapped level is fully within historical norms.

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF THE POTENTIAL DOUBLE COUNTING CONCERN.

A. As ordered by the Commission in the 2010 GRC, the Company has included a margin trading adjustment to account for the Company's historical levels of arbitrage trading activity. This value is the average total margin for the Company's short-term firm arbitrage transactions over the past 4 years. The Company may potentially raise a concern that increased GRID market sales would double count these trading transactions.

Q. DO YOU AGREE WITH THIS CONCERN?

A. No. First, the point of the arbitrage adjustment is to deal with types of short-term firm transactions that are inherently not modeled in the GRID simulation. Given the relatively remote nature of the rate year, short-term firm transactions that are executed by the

Company for arbitrage purposes as late as the day or even the hour before the delivery of power are not included in the GRID simulation. The purpose of the arbitrage adjustment is to include value for types of transactions that GRID will inherently not simulate, regardless of the type or level of cap on overall sales levels. Removing the sales caps from GRID allows the model to more efficiently balance the system on an hourly basis and is not intended to somehow include arbitrage trading opportunities that were absent in the presence of the cap.

Further, removal of the inappropriate sales caps increases the sales transactions by a relatively modest amount that is far less than the historical sales transactions. The average of the four year historical sales for deriving the caps average is approximately [redacted] MWhs. The Company's arbitrage trading adjustment is based on average sales of [redacted] MWhs. While I recognize the fact that the bilateral transactions are occurring over multiple months, the discrepancy between the historical sales result ([redacted] MWhs) and the GRID sales and trading adjustment ([redacted] MWhs) is very large. Given this gap and the inherent differences in transaction types explained above, I do not believe there would be a double counting of sales activity with the elimination of the market sales caps.

Q. PLEASE SUMMARIZE AND STATE THE IMPACT OF BOISE'S PROPOSED ELIMINATION OF THE GRID SALES CAPS.

A. The Commission should order the removal of the sales caps from the GRID model based on the analysis presented in this testimony. Based on my GRID sensitivity analysis, the removal of the caps would lower the Washington revenue requirement in this case by approximately $2.9 million.

Q. IF THE COMMISSION DOES NOT WISH TO ELIMINATE THE GRID MARKET CAPS ENTIRELY, DO YOU HAVE AN ALTERNATIVE RECOMMENDATION?

A. Yes. The issue of market caps in the GRID model was fully litigated in PacifiCorp's annual power cost filing in Oregon last year, OPUC Docket No. UE 245. In that case, the Oregon PUC adopted a compromise approach proposed by the Oregon Commission Staff. The relevant portions of the Oregon PUC order from that case are attached as Exhibit No. __(MCD-6).

Under this approach, the market caps for a particular month's on-peak and off-peak hours would be determined as the *highest* of the four years of historical data for that monthly period, rather than the average of the four values.

For example, consider a hypothetical situation where September on-peak sales at Mid-C had been 600 MW, 450 MW, 550 MW, and 400 MW in the four historical years. Under the PacifiCorp approach, the market cap for on-peak September sales would be the average of the four years, or 500 MW. Under the compromise approach, the market cap would be set at the maximum value of 600 MW from the historical years.

Q. HAVE YOU ANALYZED THE EFFECT OF THIS MARKET CAP APPROACH ON THIS CASE?

A. The effect of adopting the Oregon PUC approach to market caps would have the effect of lowering the revenue requirement in this case by approximately $1.2 million, somewhat less than half the effect of fully eliminating the caps.

Jim Bridger Heat Rate Improvements

Q. WHAT CAPITAL IMPROVEMENTS FOR JIM BRIDGER UNIT 2 IS THE COMPANY PURSUING RECOVERY FOR IN ITS GENERAL RATE CASE?

A. The Company is seeking cost recovery for a turbine upgrade project at Unit 2 of the Jim Bridger facility. The estimated cost of the project on a total Company basis is $30.9

million. The primary benefits of the project are an increase in generating capacity of 12 MW with no additional fuel requirement at maximum output. The Company also anticipates that there will be an efficiency improvement of approximately 500 British thermal units per Kilowatt hour ("BTU/kWh") over the normal operating range of the plant. The project was anticipated to start service in May of 2013. Full description of the upgrade project and its costs and benefits can be found in Exhibit No. ___(DMR-1T), the testimony of Dana Ralston.

Q. HAS THE COMPANY INCLUDED BOTH THE CAPACITY AND EFFICIENCY IMPROVEMENTS FROM THE TURBINE UPGRADE PROJECT IN THIS PROCEEDING?

A. No. The Company has not included the anticipated efficiency improvements in its power cost modeling in this case.

Q. IS THIS APPROPRIATE?

A. No. Not including the full benefits of a project while charging customers its full costs is a basic violation of the matching principle. If the Company wishes to seek recovery for the turbine upgrade at Bridger Unit 2, it must include all benefits.

Q. ARE THE EFFICIENCY BENEFITS FROM THE TURBINE UPGRADE PROJECT REASONABLY KNOWN AND LIKELY TO OCCUR?

A. Yes. In ICNU Data Request 2.3 in the UE 263 docket in Oregon, ICNU requested the Company provide the basis for the expected 500 BTU/kWh heat rate improvement. This data response is attached as Exhibit No. ___(MCD-7). As part of this response, the Company provided the results of a study performed for the turbine upgrade project completed on Bridger Unit 1. The Company presumably deemed this responsive as "Bridger Units 1 and 2 are of similar design, capacity and size."

Q. DID THE UPGRADES AT BRIDGER UNIT 1 PRODUCE SUBSTANTIAL, MEASURABLE AND IMMEDIATE IMPROVEMENTS IN THE UNIT'S HEAT RATE?

A. Yes. Based on my analysis in this case of Bridger Unit 1 operations from the 48 month period ended June 2012, the unit showed a substantial improvement in average heat rate for the 24 month period during which the turbine upgrade was in effect. Specifically, prior to May 2010 the average heat rate for Unit 1 was [redacted] BTU/kWh. From July 2010 (the first full month after the upgrade) through June 2012 the average heat rate was [redacted] BTU/kWh. This represents an improvement of [redacted] BTU/kWh.

Q. WHAT HEAT RATE DO YOU RECOMMEND BE USED FOR THE BRIDGER 2 UNIT FOR 2014.

A. I recommend that the average heat rate for Bridger Unit 1 since the time of the turbine upgrade be imputed for Unit 2 for power cost modeling purposes for 2014. This value is [redacted] BTU/kWh and represents an improvement of [redacted] BTU/kWh over the value of [redacted] BTU/kWh currently included in the GRID model for Unit 2. This represents a reasonable value in line with the Company's testimony of the expected efficiency improvement, and is also reasonable given the empirical results experienced for Unit 1 and the similarity between Units 1 and 2.

Q. DO YOU ALSO HAVE A PROPOSED ADJUSTMENT TO THE BRIDGER UNIT 1 HEAT RATE INCLUDED IN THE GRID MODEL?

A. Yes. PacifiCorp uses actual results from the most recently available 48 months to develop a scalar adjustment to the design heat rate for use in GRID. PacifiCorp described the necessity for this adjustment to design heat rates in response to Boise Data Request 4.1. The full response is attached as Exhibit No. ___(MCD-8):

> The heat rate coefficient scalar is necessary because online net generation heat rates can change over time, depending on a unit's age, operating time since overhaul, and changes in auxiliary loads (such as coal mills and scrubbers). The design heat rate coefficients capture the variance in heat rate as a function of unit output, but cannot capture the complex relationship of these other factors.

The use of the 48 month data does not allow for the timely integration of capital improvements that effectively raise the design heat rates. As described previously, the heat rate for Bridger Unit 1 showed substantial improvement in efficiency after May 2010. However, under PacifiCorp's method, customers do not see the full benefit of that improvement because using the date from the months back to July 2008 dilutes the improvement. Indeed, customers will not see the full improvement due to the turbine upgrade put in service during 2010 until 2015, all the while paying the costs through rates.

Q. WHAT HEAT RATE DO YOU RECOMMEND BE USED FOR THE BRIDGER 1 UNIT?

A. I recommend that the average heat rate of [redacted] BTU/kWh derived from July 2010 through June 2012 be used in GRID modeling for this case. This will allow customers to receive the full benefits of capacity projects they are paying for through rates.

Q. ARE THERE ANY OTHER ERRORS IN PACIFICORP'S HEAT RATE CALCULATIONS?

A. Yes. As described in response to Boise Data Request 4.1, PacifiCorp inadvertently did not include all 48 months of operating data for its thermal plants while calculating the heat rate coefficients for use in GRID. PacifiCorp intends to correct this error for all thermal plants in its next update filing. Boise has estimated the impact of this correction as a reduction of $0.1 million to the Washington revenue requirement.

Q. HAVE YOU CALCULATED THE COMBINED EFFECT OF YOUR ADJUSTED HEAT RATES ON NPC FOR THE RATE PERIOD?

A. Yes. Correcting both the Bridger Unit 1 and 2 heat rates to reflect the efficiency improvements from the turbine upgrade projects reduces the Washington revenue requirement by $0.5 million. This adjustment represents the incremental NPC change in GRID after correcting for the heat rate calculation error PacifiCorp acknowledged in response to Boise Data Request 4.1. The overall effect of Boise's heat rate recommendations would reduce the Washington revenue requirement by $0.6 million.

Jim Bridger Coal Costs

Q. PLEASE PROVIDE A BRIEF EXPLANATION OF HOW THE JIM BRIDGER COAL PLANT PROCURES ITS FUEL.

A. The Bridger plant receives its fuel from two sources. Approximately one third of the coal needs come from a third party coal source, the Black Butte mine. The remaining need is satisfied from an affiliated source, the Bridger Coal Company ("BCC"). Through an affiliate, PacifiCorp owns 66.67% of BCC, while the remainder is owned by an affiliate of the Idaho Power Company.

Q. HOW SHOULD THE BRIDGER COAL COST BE DETERMINED FOR RATE MAKING PURPOSES?

A. The coal sourced from the Black Butte mine should be evaluated and assessed under the usual rate setting standard of whether or not the cost is prudent and reasonable. For the coal sourced from the Company affiliate, however, a different standard is warranted. For affiliated coal costs the standard should be the lower of the market value or actual cost. By establishing the affiliated cost in this manner, ratepayers are protected from affiliate abuse by the Company paying an unreasonable price which would allow the affiliate and parent corporation to achieve above market profits.

Q. ARE THERE AGREEMENTS IN WASHINGTON THAT GOVERN THE USE OF LESSER OF COST OR MARKET FOR AFFILIATE TRANSACTIONS BY PACIFICORP?

A. Yes. As part of the agreement to allow the MEHC acquisition of PacifiCorp, the Company agreed to the following for Washington:

> MEHC and PacifiCorp agree to use asymmetrical pricing for affiliate charges or costs not covered by the provisions of the InterCompany Administrative Services Agreement (IASA), if a readily identifiable market for the goods, services or assets exists, and if the transaction involves a cost of more than $500,000.[2/]

Q. DOES THE BLACK BUTTE CONTRACT REPRESENT A REASONABLE VALUE FOR THE LESSER OF COMPARISON BETWEEN AFFILIATE SUPPLY COSTS AND MARKET COSTS?

A. Yes. The Black Butte contract is a third party supply contract for coal supply at the Jim Bridger plant that PacifiCorp obtained through solicitation of the market. Also, the contract is not fixed price but rather its components are escalated annually by a series of third-party cost indices. Thus, the contract price for 2014 will represent a fair and current market value for the year.

Q. HOW DOES THE PRICE OF COAL FROM THE BCC COMPARE TO THE COST OF COAL FROM THE BLACK BUTTE CONTRACT?

A. To make an appropriate comparison of coal costs from the BCC and Black Butte contract sources, it is necessary to account for the both the differences in heat rates between the coal sources as well as the return on investment that the Company earns from the rate base treatment of BCC assets that PacifiCorp owns through its affiliate. When including

[2/] Application of MEHC and PacifiCorp, Docket No. UE 051090, Order No. 7, Appendix at 13, Wa-12 (Feb. 22, 2006).

these factors, the all-in equivalent BTU price for BCC coal is [redacted] per ton while the cost of Black Butte contract coal is [redacted] per ton. This represents a difference of approximately [redacted] per ton or [redacted]

Q. WHAT SPECIFIC ADJUSTMENT DO YOU RECOMMEND GIVEN THE LOWER PRICE OF MARKET COAL SUPPLY RELATIVE TO THE AFFILIATED COSTS OF COAL FOR THE JIM BRIDGER FACILITY?

A. I recommend that all coal for the Jim Bridger plant be priced equivalent to the Black Butte contract for modeling purposes in this proceeding.

Q. WHAT IS THE EFFECT OF THE ADJUSTMENT?

A. The effect of this adjustment is to lower the Washington revenue requirement in this case by approximately $5.1 million.

OATT Revenues

Q. HAS NEW INFORMATION ABOUT THE COMPANY'S LIKELY LEVEL OF OATT REVENUE BECOME AVAILABLE SINCE THE COMPANY'S ORIGINAL FILING?

A. Yes. The Company's response to WUTC Data Request 225 shows that the Company has reached a settlement in FERC Docket Nos. ER11-3643-000 and ER11-3643-001. This data response is attached as Exhibit No. ___(MCD-9).

Q. WHAT IS THE NET EFFECT ON OATT REVENUES ESTIMATED BY PACIFICORP AS THE RESULT OF THE SETTLEMENT?

A. Based on PacifiCorp's response to WUTC Data Request 225, it appears the Company expects to receive approximately $0.3 million (Washington basis) in additional OATT revenue in 2014 relative to its filed case.

Q. SHOULD THIS ADDITIONAL REVENUE BE INCLUDED AS AN OFFSET TO PACIFICORP'S FILING IN THIS CASE?

A. Yes. PacifiCorp's response to this data request represents the most current evidence for OATT revenues for 2014, and should be included as an adjustment to PacifiCorp's requested revenue requirement.

POWER COST ADJUSTMENT MECHANISM

Q. HAS THE COMPANY PROPOSED A PCAM IN THIS PROCEEDING?

A. Yes. The Company has proposed a PCAM to collect or credit any differences between actual and forecasted power costs in Washington rates. On a monthly basis the Company would compare actual system net power costs ("Actual NPC") with net power costs included in rates and place any differences in a balancing account with interest. After the accrual of a positive or negative balance of $5 million in Washington NPC, the Company would calculate a PCAM rate to collect or credit the accumulated balance in the following year.

Notably, the Company's proposal would be for a dollar-for-dollar true up to Actual NPC, with no use of a deadbands, sharing bands, or an earnings test. Full details of the Company's PCAM proposal are presented by Gregory Duvall in Exhibit No. ___(GND-1CT).

Q. HAS THE COMMISSION REJECTED A SIMILAR PCAM FROM PACIFICORP IN THE PAST?

A. Yes. As observed in PacifiCorp's testimony, the Commission rejected PacifiCorp's PCAM proposal in the 2005 rate case, stating that a "90/10 sharing band and the absence of a deadband do not adequately balance risk and benefits between shareholders and ratepayers."[3/]

Q. SHOULD THE COMMISSION REJECT PACIFICORP'S PROPOSED PCAM IN THIS PROCEEDING ON THE SAME BASIS?

A. Yes. The Company's proposal in this case suffers from the same deficiencies to an even greater degree, given that now there is now not even a proposed sharing band. The Company is attempting to re-litigate PCAM policy issues that the Commission has already decided.

Q. WHAT IS THE COMPANY'S BASIC JUSTIFICATION IN ASSERTING THE NEED FOR A PCAM IN WASHINGTON?

A. The Company asserts two basic arguments to justify the need for a PCAM in Washington. First, the Company asserts that during the five year period from 2007 through 2011, it has under-recovered its Actual NPC relative to the NPC embedded in Washington rates by approximately $54.6 million. Second, the Company argues that in complying with Washington state energy policy, it now relies on a much higher proportion of wind and natural gas facilities, which increases NPC variability and risk.

Q. ARE THESE JUSTIFICATIONS COMPELLING?

A. No. The fact that the Company has happened to incur greater than forecasted power costs is not evidence of a failure of the normalized rate making process. This would be similarly true with a pattern of lower than expected power costs. Actual power costs can vary from the normalized forecast for a huge variety of reasons, including variations in weather, load, market prices, and resource performance.

[3/] Wash. Utils. & Transp. Comm'n v. PacifiCorp, Docket No. UE-050684, Order 04, ¶ 99 (April 17, 2006) (2005 Rate Case).

Q. HAS THE COMPANY SHOWN THAT ITS HISTORICAL VARIATIONS IN ACTUAL POWER COSTS RELATIVE TO RATES IS DRIVEN BY CHANGES IN ITS RESOURCE PORTFOLIO TO COMPLY WITH WASHINGTON LAW?

A. No. As shown in the following table, the actual variance in PacifiCorp's power costs has been *decreasing* in recent years. If variability and risk in PacifiCorp's power costs was increasing on an annual basis as a result of compliance with renewable energy standards, then the opposite pattern should be observed in the historical data.

Table 2. NPC in Rates vs. Actual (000's)

	2007	2008	2009	2010	2011
In Rates	$91,233	$92,542	$95,704	$109,062	$115,956
Actual NPC	$106,817	$111,496	$107,667	$110,475	$122,680
Difference	$15,584	$18,954	$11,963	$1,413	$6,724
% Variance	17%	20%	13%	1%	6%

Q. HAS THE COMPANY CONVINCINGLY ESTABLISHED THAT IT IS UNABLE TO RECOVER ITS POWER COSTS ON A NORMALIZED BASIS AS A RESULT OF COMPLIANCE WITH WASHINGTON LAW?

A. Absolutely not. The Company expounds at great length on the challenges of integrating increasing amounts of wind integration on its system. I fully acknowledge that the issue of integrating variable output renewable resources is a challenge that has associated costs. However, on a normalized, annual basis these costs can be and are forecasted on a reasonable basis.

Specifically, the Company's power cost forecast includes modeling components for costs related to wind integration based on its 2012 Wind Integration Resource Study (2012 Wind Study). The Company describes this study as "the result of an extensive public process that received guidance from a Technical Review Committee that included numerous subject-matter experts."[4/]

Mr. Duvall goes on to state that: "The Company believes that the level of reserves required to integrate wind generation net of system load, as identified in the 2012 Wind Study, is appropriate."[5/] If the Company does not believe that the reserve levels it has modeled in its case and the approximate $3.13 per MWh of wind integration costs in its filed case are accurate, then it should have proposed different values. A PCAM that is structured in direct contradiction to the Commission's orders to the Company is not an appropriate solution, to the extent that there is even a problem to correct.

Q. DID THE COMPANY RECENTLY PROPOSE A SIMILAR PCAM MECHANISM IN OREGON WITH SIMILAR JUSTIFICATION?

A. Yes. The Company made an extremely similar proposal for a PCAM with similar justification in the UE 246 docket last year in Oregon. Upon review of the fully developed record in that case, the Oregon PUC firmly rejected PacifiCorp's proposal and reasoning. The relevant sections of that order are attached to this testimony as Exhibit No. ___(MCD-10).

Q. IF THE COMMISSION WISHES TO GRANT PACIFICORP A PCAM IN THIS PROCEEDING, DO YOU HAVE A RECOMMENDED STRUCTURE?

A. Yes. In the case that the Commission wishes to grant PacifiCorp a PCAM in this proceeding, I recommend the adoption of a similar structure to the PCAM recently approved by the Oregon PUC in the Company's recent UE 246 rate case.

4/ Exhibit No. ___(GND-1CT), at 25, ll. 4-5.
5/ Id., ll. 7-9.

Specifically, such a PCAM would include an earnings test, asymmetric deadbands, and a sharing mechanism for power cost variations outside the deadband. I recommend an earnings test that would not allow refund or collection of power cost variations if PacifiCorp's earnings are within 100 basis points of its authorized level. I recommend a deadband that would not change rates when excess power costs were less than the equivalent of 150 basis points of authorized ROE or when power cost savings were less than the equivalent of 75 basis points of the utility's authorized ROE. Regarding a sharing mechanism, Boise recommends that any amount of power cost variation that would be subject to refund or collection after the application of the deadband and earnings test should be shared between shareholders and ratepayers on the basis of 25% to shareholders and 75% to ratepayers.

Q. PLEASE DESCRIBE THE BENEFITS OF THIS PROPOSED PCAM STRUCTURE.

A. The fundamental purpose of the earnings test is to protect consumers from paying for higher than expected power costs when the Company's earnings are reasonable while also protecting the Company from refunding power costs when its earnings are otherwise unreasonably low.

A deadband is set in a PCAM to ensure that the Company absorbs variations in power costs incurred in the normal course of business. A utility's return on equity constitutes compensation for the risk of events occurring in the normal course of business. Further, an asymmetric deadband is important to ensure revenue neutrality in a region heavily dependent on hydro power, as the replacement costs of hydro power in poor water years will outweigh the benefit of additional hydro energy in good years.

Also, aside from hydro power specifically, a utility's power costs typically have more room for variation above projected levels than below. Thus, the purpose of a PCAM is to protect a utility from extreme power cost fluctuations and not to provide dollar-for-dollar recovery of actual costs.

Finally, a cost sharing mechanism for costs outside of the deadband (i.e., certain percentages of costs being borne by the Company and customers) provides incentive for the Company to continue to manage its costs effectively under unusual circumstances, but also to provide cost sharing for events beyond the normal course of business.

RATE SPREAD

Q. WHAT HAS THE COMPANY PROPOSED REGARDING RATE SPREAD IN THIS PROCEEDING?

A. The Company is generally proposing to spread the revenue requirement based on the results of its cost of service study. Specifically, the Company is proposing below average system increases for Schedules 24, 40, and lighting, system average increases for Schedules 36 and 48T (excluding dedicated facilities customers), and above average increases for residential customers and Schedule 48T Dedicated Facilities.

Q. DO YOU SUPPORT THE COMPANY'S RATE SPREAD PROPOSAL IN THIS PROCEEDING?

A. No. Based on the results of the Company's cost of service study, I do not support substantially above average increases for the residential class and Schedule 48T Dedicated Facilities. A more equitable rate spread would be for below average increases to Schedules 40 and lighting with all other classes receiving an equal percentage increase. Specifically, I recommend that street lighting schedules receive 50% of the system average increase, Schedule 40 receive 75% of the system average increase, and all remaining classes receive an equal percentage increase.

At the Company's full requested increase, this would constitute a 7.0% increase for street lighting, 10.6% for Schedule 40, and 14.3% for all other classes. At an overall revenue requirement increase of $10 million, or approximately 3.3%, my rate spread proposal would constitute a 1.6% increase for street lighting, 2.5% for Schedule 40, and 3.3% for all other classes.

The best measure of the level of customer class rate levels relative to cost of service is the "parity ratio" statistic. The parity ratio takes the normalized revenues from a customer class divided by the class cost of service. A customer class with a parity ratio greater than 1 would be contributing revenue over its cost of service, while a ratio below 1 indicates under recovery of costs. The table below presents parity ratios for each customer class based on the Company's proposed cost of service study. The ratios are based on the class cost of service at the Company's uniform current rate of return. This is more appropriate than the proposed rate of return, as a utility is not guaranteed to achieve its authorized rate.

Schedule No.	**Description**	**Parity Ratio**
16	Residential	0.97
24	Small General Service	1.09
36	Large General Service <1,000 kW	1.02
48T	Large General Service >1,000 kW	0.99
48T	Dedicated Facilities	0.94
40	Agricultural Pumping Service	1.11
15,52,54,57	Street Lighting	1.19
Overall	Total	1.00

The Commission has traditionally supported equal percentage increases for classes within 10% of parity. As the table demonstrates, all classes except street lighting and irrigation are within that band. My proposal would give proportionally smaller increases to the schedules outside of the 10% band and an equal percentage to all other classes, consistent with Commission precedent.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.