Q. Please state your name, business address and present position with PacifiCorp, dba Rocky Mountain Power (the "Company").

A. My name is Brian S. Dickman. My business address is 825 NE Multnomah St., Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs.

Q. Are you the same Brian S. Dickman who submitted direct testimony and response testimony on behalf of the Company in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. My testimony responds to certain issues raised by Mr. Kevin C. Higgins on behalf of the Utah Association of Energy Users Intervention Group ("UAE") and Mr. Philip Hayet on behalf of the Office of Consumer Services ("OCS").

Q. Please summarize the Company's response to the specific adjustments proposed by UAE and OCS that are addressed in your testimony.

A. My testimony responds to two proposed adjustments as summarized below:

1. **Non-owned Wind Integration -** The Federal Energy Regulatory Commission ("FERC") approved the Company's Open Access Transmission Tariff ("OATT") Schedule 3A to provide recovery of the capacity costs required to integrate third-party wind resources. UAE and OCS now argue that the revenue approved for collection is not adequate, and both impute a credit to retail customers for lost opportunity costs related to OATT wind integration. The effect of the proposed adjustments is to charge OATT customers for the capacity held to integrate their wind projects *and* allow the same capacity to be used to make off-system sales to generate a margin to be credited back to retail

customers, providing double benefits to retail customers. Since revenue from OATT customers is already passed back to retail customers, there is no need to impute an additional credit to retail customers for lost opportunity costs related to OATT wind integration.

2. **Direct Current ("DC") Intertie Contract -** The Company uses its rights on the DC Intertie to serve customers in Central Oregon. This contract is essential to system operations in the Company's western control area. The Company's 2013 Integrated Resource Plan ("IRP") relies on the contract to provide system capacity through 2032, and eliminating the contract would require the Company to purchase other capacity to serve customers.

Q. Do any other Company witnesses also provide rebuttal testimony in response to issues raised by OCS and UAE?

A. Yes. Company witness Mr. Dana M. Ralston provides testimony concerning plant outages.

Third-Party Wind Integration

Q. Please describe the adjustments pertaining to third-party wind integration as proposed by UAE and OCS.

A. Both UAE and OCS claim the revenue collected pursuant to the Company's OATT does not provide the Company with adequate compensation from wholesale transmission customers to cover the cost of integrating third-party wind generation. UAE argues the OATT does not include recovery of the opportunity cost of holding back reserves to support third-party wind integration. OCS argues that the OATT only covers capacity costs and does not cover variable costs of fuel and purchased power. UAE and OCS both propose to impute a credit to the EBA based on the impact of holding reserves quantified in Docket No. 11-035-200 (the "2012 general rate case"). UAE and OCS propose reducing the EBA by approximately $1.2 million and $898,000 respectively.

Q. Please provide some background on how the Company provides service to its retail and transmission customers.

A. As a regulated electric utility, the Company is obligated to provide power and ancillary services to serve retail customers at embedded cost. In addition, as a transmission provider regulated by the FERC, the Company is obligated to provide ancillary services to transmission customers at embedded cost. To provide these services to both retail and transmission customers, the Company effectively allocates a portion of its resources to each group. In the same way they pay for transmission service, wholesale customers pay OATT rates to cover the embedded cost of the generation resources required to provide ancillary services, and these resources are no longer available to provide benefits to retail customers.

Q. What is meant by third-party wind integration?

A. Third-party wind generators are projects that are located in the Company's balancing authority and transmission service provider service area, but do not provide any power to help meet the Company's load. The Company's OATT requires the Company to provide ancillary services, including regulation and frequency response, to manage the wholesale wind generators' moment-to-moment variability.

Q. Does the Company recover the cost of integrating third-party wind generators through its OATT?

A. Yes. The Company recovers the cost of integrating third-party wind generators by charging the projects directly through OATT Schedule 3A for the capacity required to manage their moment-to-moment variability. Schedule 3A was implemented through the Company's transmission rate case ER11-3643-000 with FERC, and the Company began collecting revenues under Schedule 3A on January 1, 2012. OATT Schedule 9 also provides compensation for generator imbalance when there is a difference between the actual energy output of the third-party generator compared to its scheduled output.[1]

Q. How are Schedule 3A rates calculated?

A. Schedule 3A rates are based on the fixed costs of PacifiCorp's generating units used to provide the necessary reserves to manage the moment-to-moment variations in the output of third-party wind projects. The result is that third-party wind projects pay for a portion of the capacity used to provide reserves, and this payment is credited back to the Company's retail customers through wheeling revenue.

Q. Do third-party generators pay both Schedule 3A and Schedule 9 under the Company's OATT?

A. Yes. The Company's testimony in its April 1, 2013, filing with FERC supporting an update to Schedule 3 and 3A rates describes how the schedules work:

> Schedule 3A recovers the Company's costs associated with holding generation capacity on-line and available to mitigate the moment-to-moment variations in generation output on an intra-hour basis.

[1] Third-party generators exporting from PacifiCorp's balancing authority area are subject to Schedules 3A and 9. OATT customers that serve third-party load within PacifiCorp's balancing authority area are subject to Schedule 3 Regulation and Frequency Response Service, and Schedule 4 Energy Imbalance Service.

> Schedule 9 recovers the costs of imbalance energy the Company must provide or accommodate when a difference occurs between the output of a generator located in a BAA and a delivery schedule from that generator based on output and schedule changes at the beginning of the scheduling hour and the end of the scheduling hour. In sum, Schedule 3A is a capacity-based charge and Schedule 9 is an energy-based charge that includes possible penalties to encourage accurate scheduling practices, consistent with Commission precedent acknowledging the difference between these charges.[2]

Q. Do retail customers benefit from the Company's OATT?

A. Yes. In 2013 the Company received over $84 million in wheeling revenue through the various OATT schedules. These revenues are passed on to retail customers as a benefit, and could not have been received without providing all FERC-required services including third-party wind integration.

Q. What is the cost of third-party wind integration that UAE and OCS propose to remove from the EBA?

A. The proposals to remove costs related to third-party wind integration are described slightly differently by UAE and OCS, but in concept they are the same adjustments. Both state that the OATT only provides revenue covering capacity costs of holding reserves. UAE further argues that the OATT does not include any recovery of the opportunity cost of holding back generation capacity to provide reserves rather than make off-system sales. The OCS argues that the OATT does not cover the variable costs of fuel and purchased power associated with providing third-party wind integration.

Q. Is there an opportunity cost associated with third-party wind integration as suggested by UAE?

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[2] Docket No. ER13-1206-000, Exhibit No. PAC-1, page 16.

A. No. Opportunity cost refers to the benefit that would have been received had an alternative action been taken. In the case of providing third-party wind integration there is no alternative action that could have been taken, and therefore there is no opportunity cost. UAE's suggestion that the Company could use its capacity to make off-system sales in place of providing capacity for the regulation reserve is mistaken. As the balancing authority and OATT service provider the Company has no other alternative but to provide these services to third-party wind generators.

Q. Is UAE correct that the Company charges retail customers the opportunity cost of holding reserves for wholesale customers?

A. No. The reserves held to integrate third-party wind resources are offset by the generation capacity that is included in the GRID model but that is paid for by these wholesale customers through the OATT rates. UAE states that the Company included wind integration costs of $3.44/MWh in the net power costs projected in its most recent general rate case. However, this is not a charge that is added to net power costs as implied by UAE. Rather, for informational purposes the Company has typically calculated the impact on projected net power costs from holding capacity in reserve to provide wind integration. The impact on net power costs of holding reserves is compared to the total wind generation in the test period to develop a figure that can be referenced and compared across different studies; in the 2012 general rate case the result was a cost of $3.44/MWh for the test period ending May 2013.

Q. What is the practical effect of UAE's proposed adjustment to impute additional revenue in the EBA?

A. In effect, UAE is proposing that the Company should charge OATT customers for the capacity held to integrate their wind projects *and* allow the same capacity to be used to make off-system sales to generate a margin to be credited back to retail customers. Since revenue from OATT customers is already passed back to retail customers, implementing UAE's proposal would provide double benefits to retail customers. UAE's proposal is not reasonable or practicable.

Q. Did you find any errors in UAE's calculation of the proposed wind integration adjustment?

A. Yes. Notwithstanding my overall objection to the proposed adjustment, I note that UAE incorrectly calculated the dollar impact of its adjustment. To arrive at the total Company impact of the adjustment, UAE applied integration costs identified in the 2012 general rate cases to the actual volume of third-party wind generation during the 2013 deferral period. However, there are two errors in UAE's calculation of the adjustment.

First, the third-party wind generation should not include BPA Foote Creek II and PSCo Foote Creek III. During the deferral period the Company did not provide integration services to these customers under OATT. Rather, an exchange contract existed with specific charges for wind integration, and the revenue for such is passed onto retail customers as a benefit. These exchange contracts expire during 2014, and for purposes of the forecasted test period in the previous general rate case the Company assumed the facilities would become OATT customers.

Second, UAE used $3.44/MWh for integration costs from the 2012 general rate case to impute revenue during the deferral period. This amount includes the net power cost impact of holding reserves for integration, as discussed in detail previously, as well as the impact of rebalancing the Company's resource portfolio due to deviations from the wind generation schedule relied on to commit thermal resources for the next day. This cost is not applied to third-party generators in the general rate case and should not be included as part of an adjustment to the EBA. If this cost is excluded, the integration costs from the 2012 general rate cases are $2.56/MWh.

These two corrections account for the difference between the adjustments proposed by UAE and OCS.

Q. Do you agree with the claim made by the OCS that the Company is not compensated for the fuel and purchased power costs associated with providing third-party wind integration?

A. No. As noted above, OATT Schedule 9 accounts for times when there is a difference between the actual energy output and the scheduled energy output from a generator. If there is no imbalance, fuel and purchased power costs do not increase.

Q. Both UAE and OCS cite a decision from the Idaho Public Utilities Commission disallowing third-party wind integration costs. How do you respond?

A. Notably, this decision was made prior to the implementation of Schedule 3A from the Company's FERC rate case. In addition, they fail to mention that the Utah and Oregon Commissions have allowed third-party wind integration costs in previous orders.

Q. What was the OCS position on third-party wind integration in the last EBA proceeding (Docket No. 13-035-32)?

A. As noted by Mr. Hayet, OCS witness Mr. Dan Gimble did not recommend an adjustment but stated "If a future FERC rulemaking or other policy mandate allows utilities to add a variable cost component to the charge for wind integration services, PacifiCorp should promptly petition the FERC to change its OATT accordingly."[3]

Q. Has there been any "FERC rulemaking or other policy mandate" that would allow the Company to add a variable cost component to its OATT tariff?

A. No.

Q. The OCS states that in Docket No. ER13-1206 PacifiCorp requested authority to increase its Schedule 3A rates. Was the purpose of that filing to add a variable cost component to Schedule 3A of its OATT tariff?

A. No. The Company's filing in Docket No. ER13-1206 was made to establish differentiated rates within Schedule 3A for variable energy resources ("VERs") and non-VERs. The filing did not add a variable cost component for calculating the costs recovered through Schedule 3A. As described by the OCS, in August 2013 FERC rejected the Company's filing, and identified that the Company's filing did not adequately consider the operational reforms of FERC's Order No. 764 on intra-hour scheduling issued in November 2013.

Q. Please explain the Company's reasoning for waiting to refile until 2016.

[3] Docket 13-035-32, Gimble Redacted Direct, Pg. 5, line 130-131.

A. As noted by the OCS, the FERC order rejecting the Company's filing in 2013 indicated that more detailed information would be required concerning the current operational practices for variable energy resources and cost savings that would result from intra-hour scheduling required by Order 764. PacifiCorp anticipates operational improvements in its ability to identify regulating reserve requirements in conjunction with its planned October 2014 implementation of the Energy Imbalance Market ("EIM"). To allow a full year of EIM operational data in addition to Order 764 operational reforms, the Company's next FERC filing is targeted for 2016.

Q. Do you believe it is appropriate to impute a reduction to the EBA to remove third-party wind integration costs?

A. No. The Company is required to provide services necessary to integrate wind resources delivered by wholesale customers under federal law and as a function of being an OATT service provider and balancing authority area. Third-party wind integration services cannot be separated from the other OATT services the Company is required to provide. The Company has FERC tariff schedules in place to recover the cost of integrating non-owned wind generators located in PacifiCorp's balancing authority area. The Company cannot charge OATT customers for the capacity held to integrate their wind projects *and* allow the same capacity to be used to make off-system sales to generate a margin to be credited back to retail customers.

DC Intertie Contract

Q. Please explain the adjustment proposed by UAE for costs associated with the DC Intertie contract.

A. UAE argues the costs associated with the DC Intertie should be removed from the Deferral Period because the contract cost was unreasonable when compared to its benefit. UAE argues that the contract cost was unreasonable since the Company only used it to transfer energy a limited number of times in the Deferral Period. The impact of the proposed adjustment is a reduction of $1,446,806 to the EBA balance.

Q. Please provide some background on the DC Intertie contract.

A. In anticipation of the expansion of the Alternating Current ("AC") Intertie to 4,800 MW, PacifiCorp and the Bonneville Power Administration ("BPA") reached a settlement of outstanding issues about the right to use the AC and DC Interties and the Midpoint-Medford transmission line. The settlement was documented in a Letter of Understanding ("LOU") which was executed on May 28, 1993.[4] As a result of the LOU, PacifiCorp received 400 MW of bidirectional rights on the AC Intertie, priority rights to an additional 125 MW of southbound transmission, four additional delivery points to the AC Intertie, and 200 MW of northbound rights on the DC Intertie. BPA received rights to up to 400 MW of eastbound transmission on PacifiCorp's Summer Lake-Midpoint line, rights to certain PacifiCorp transmission, and the option to take energy under spring and summer exchanges. The agreement states that the DC Intertie contract term will be equal to the term of the AC Intertie agreement, and that the AC Intertie agreement is extended for the

[4] A copy of the LOU was provided as Exhibit RMP___(GND-2) accompanying the direct testimony of Gregory N. Duvall in the Company's last general rate case, Docket No. 13-035-184.

life of the facilities it covers. These rights are functionally equivalent to ownership. Consistent with the LOU, the DC Intertie contract was executed on May 26, 1994.

Q. Why is this background important?

A. It is important because under the LOU, BPA and PacifiCorp agreed that the provisions of the LOU are interdependent and not severable. In other words, an analysis of the DC Intertie cannot be conducted without addressing all of the other rights and obligations PacifiCorp signed up to in the LOU.

Q. Is there a benefit in having a contract like the DC Intertie for Company's customers today?

A. Yes. The DC Intertie is a valuable transmission asset to the Company and its customers. The contract provides a means to secure capacity and energy from California sources in order to reliably meet retail loads. The transmission rights take advantage of the load diversity between summer-peaking California and the winter-peaking Pacific Northwest and represent an integral piece of the transmission network for maintaining reliability in PACW. The DC Intertie contract is the only PacifiCorp contract that provides firm import rights from the Nevada-Oregon Border ("NOB") market, thereby providing unique market diversity to the Company for the benefit of retail customers.

Q. Does the Company include purchases at NOB and utilization of the DC Intertie in its Integrated Resource Plan ("IRP")?

A. Yes. The Company's 2013 IRP relies on market capacity from the DC Intertie and the NOB market to serve peak load. Between 2013 and 2032, the Company's 2013 IRP preferred portfolio selected 100 MW of front office transactions from the NOB market annually to reliably meet its retail loads. If the DC Intertie was not available in the IRP, the Company would be required to acquire capacity from another source. An analysis completed using the Company's IRP models with and without the DC Intertie capacity shows higher system costs if the DC Intertie is excluded, with the 20-year present value revenue requirement differential benefit of the DC Intertie exceeding $85 million.

Q. UAE cites that the Company identified only a limited number of transactions that 'could' have used the DC Intertie during the Deferral Period. Is this a cause for concern?

A. No. The transactions utilizing the DC Intertie during the Deferral Period were real-time transactions used to balance the Company's system when power was needed. UAE minimizes the need for these transactions by averaging the hourly megawatts purchased, and emphasizing the number of hours the maximum capacity of 200 MW was utilized. The DC Intertie is a direct connection to the California ISO and other counter-parties, which operate on a day-ahead, hour-ahead and real-time basis. The Company can, and does, count on the DC Intertie for access to a market that provides the Company with the assured ability to purchase next hour. In the Company's experience, the California ISO is always a willing counter-party. UAE's testimony shows that the contract is used and useful, but it seems UAE's argument is that the DC Intertie is not 'used and useful enough'.

Q. Is the cost of the DC Intertie out of line with the cost of other transmission?

A. No. For example, point-to-point transmission service under the Company's OATT, including scheduling, costs approximately $2.35 per KW-month, and the cost of the DC Intertie is approximately $1.98 per KW-month.

Q. Has the cost of the DC Intertie contract already been included in Utah rates?

A. Yes. The Company's approved Utah rates have included the cost of the DC Intertie contract for many years. These costs have been specifically included in at least the last 6 general rate cases, since Docket No. 07-035-93. Notably, these costs were also included in Docket No. 09-035-23, the last fully litigated Utah general rate case, and no adjustment was proposed to remove them at that time.

Furthermore, in the 2012 EBA, Docket No. 12-035-67, the Commission approved a stipulation that allowed the cost of the DC Intertie to remain in the EBA and provided that parties to the stipulation "will not challenge rate treatment of the DC Intertie…on the basis of imprudence of the original contracts or actions the Company undertook or failed to undertake related to the contracts through December 31, 2012."

Q. Was UAE party to the stipulation in the 2012 EBA?

A. No.

Q. UAE claims that the Company has not undertaken any steps to determine if there are options available to renegotiate, modify, terminate or buy out the DC Intertie contract. Can the Company resell or renegotiate the rights to the DC Intertie contract?

A. No. Transmission capacity under BPA's Formula Power Transmission ("FPT") rates cannot be resold. BPA's business practices only allow for the resale of transmission rights for PTP service. Renegotiating the DC Intertie contract would likely open up all of the issues that were agreed to by BPA and the Company under the LOU because the premise of the LOU was that the multiple parts of the LOU are interdependent and not severable.

Q. Can the Company terminate the DC Intertie contract?

A. Yes. The right to terminate the DC Intertie contract is triggered by termination of the AC Intertie agreement. If this were to occur, the Company would no longer have the ability to sell wholesale power over the AC Intertie. This outcome would certainly increase NPC. For example, in the 2012 general rate case Base NPC included $34.3 million in sales at the California-Oregon Border ("COB") market.

Q. How should the Commission judge the prudence of this contract?

A. Whether it was prudent to acquire the contract years ago should be judged based on the information that was known at the time the contract was executed. The Company's approved rates in Utah have included the DC Intertie for many years and it continues to be used and useful today, providing access to a liquid market and a ready source of power for its customers. The LOU illustrates that the DC Intertie is an integral piece of the transmission network in PACW for meeting load and providing access to wholesale power over the DC Intertie as well as the AC Intertie.

Q. Does this conclude your rebuttal testimony?

A. Yes.