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 Dickman who filed direct and supplemental direct testimony in this proceeding?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony first responds to certain issues addressed in the supplemental direct testimony of Mr. Matthew Croft and Mr. Richard S. Hahn of the Utah Division of Public Utilities ("Division") and the direct testimony of Dr. J. Robert Malko of the Utah Industrial Energy Consumers ("UIEC") related to the Division's Audit Report. Next, I respond to various adjustments proposed in the direct testimony of Mr. Randall J. Falkenberg on behalf of the Office of Consumer Services ("OCS"). Finally, I discuss the proposals made for additional information to be provided in future EBA filings.

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

A. Yes. The Company is introducing three additional witnesses: Mr. Stefan A. Bird, Senior Vice President Commercial & Trading, and Mr. Frank C. Graves, Principal for The Brattle Group, respond to hedging related issues raised by UIEC; and Mr. Dana M. Ralston, Vice President of Thermal Generation, responds to the adjustments proposed by the Division and OCS related to plant outages in the Deferral Period.

Q. Has the Company made any corrections or updates to the EBA deferral amount since its supplemental direct filing on December 13, 2012?

A. No. The Company has not identified any corrections or updates since its December 13, 2012, filing.

AUDIT REPORT ISSUES

Q. Did the Division file supplemental testimony revising its recommendation in its initial Audit Report?

A. Yes. On December 13, 2012, the Division filed supplemental direct testimony wherein it updated its recommendations regarding the EBA deferral amount. Based on the additional information provided by the Company since the initial Audit Report was filed, the Division recommended two adjustments to the EBA deferral: a $0.3 million dollar increase for out-of-period accounting entries and a $2.7 million dollar decrease for outages at certain thermal generating facilities. The Company incorporated the adjustment for out-of-period accounting entries in its December 13, 2013, supplemental direct filing. Company witness Mr. Ralston provides rebuttal testimony responding to the recommended reduction due to thermal generation outages.

Q. Have the various accounting and reconciliation issues raised in the Audit Report been resolved?

A. Yes. Mr. Croft identified seven items, in addition to plant outages, that remained open in the initial Audit Report. Mr. Croft's testimony confirms that all issues surrounding supporting documentation for power and gas transactions, both physical and financial, and reconciliation of variances between two power physical reports have been resolved.

Mr. Hahn confirms in his testimony that the Company adequately explained the non-outage related variance in output from coal and gas generation. He also explains that the Company provided supplemental information that summarized short-term transactions by market hub to facilitate a comparison between actual transactions and modeled transactions in GRID. He says the data was broken out without consideration of book-outs so he was not able to complete his comparison. Mr. Hahn comments that he also received helpful information supporting the purpose of certain power and gas transactions, and will continue to explore this area of the Company's business in future proceedings.

Neither Mr. Croft nor Mr. Hahn recommended any adjustments to the EBA deferral related to these items.

Q. Do you have any comments regarding the breakout of short-term firm transactions by market hub?

A. Yes. It is important to note that the Company provided transaction level detail for every short-term purchase and sale transaction with relevant data including points of delivery and receipt as part of the filing requirements with the original filing. The supplemental information provided by the Company at Mr. Hahn's request summarized the detailed transactions into generalized market hubs in a similar format as the GRID model output. Furthermore, the issue of bookouts was addressed in the initial Audit Report and the Division confirmed that bookouts have a net impact of zero on the EBA.

Q. Do you agree with UIEC witness Dr. Malko that, based on Mr. Hahn's preliminary assessment, short-term firm purchases and sales have not been shown to be prudently incurred?

A. No. As described above, the Company provided detailed information supporting the actual short-term firm transactions in the Deferral Period. In addition, the Company worked with the Division to provide additional information supporting the short-term firm purchases and sales and participated in follow-up conference calls to explain the nature of these transactions. In Mr. Hahn's supplemental testimony he did not recommend any adjustment related to these transactions.

Q. Did Dr. Malko present any of his own evidence supporting an adjustment to short-term purchase and sale transactions?

A. No. With no supporting evidence, Dr. Malko claims that the variance between forecast and actual short term firm purchases and sales may have been associated with day trading and should not be recovered through the EBA. The testimony of Company witness Mr. Bird explains that the Company does not engage in speculative day trading and Dr. Malko's proposal is without merit.

REBUTTAL OF PROPOSED ADJUSTMENTS

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

A. My testimony responds to five specific adjustments proposed by the OCS as listed below.[1]

1. **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 2011 Integrated Resource Plan ("IRP") Update relies on the contract to provide system capacity through 2031, and eliminating the contract would require the Company to purchase other capacity to serve customers.

2. **Centralia Point-to-Point ("PTP") Contract –** The current use of the Centralia PTP contract represents the most cost-effective use of the contract capacity under current circumstances. Utilization of the Centralia PTP contract changed when the Company acquired the Chehalis generating station and accompanying transmission rights, a transaction that was in the best interest of customers. The Company has actively managed the Centralia PTP contract by reselling capacity where possible and redirecting capacity on other transmission paths.

3. **Legal Fees at Owned Mines –** The legal expenses described by OCS witness Mr. Falkenberg are related to ongoing legal matters common to the operation of the Company's owned mines. The expenses identified are properly included in the Deferral Period and are not, as claimed, expenses belonging to prior periods.

4. **Huntington Unit 2 Contractor Delay –** Liquidated damages clauses are routinely included in contractual agreements with contractors performing planned overhaul work. Mr. Falkeberg's proposal is an unbalanced penalty to the Company with no supporting evidence of imprudence.

5. **Non-owned Wind Integration –** Costs related to providing wind integration services to Open Access Transmission Tariff ("OATT") customers are properly included in the Deferral Period. The Company was diligent in filing a transmission rate case after the Federal Energy Regulatory Commission ("FERC") issued its Notice of Proposed Rulemaking ("NOPR") establishing the mechanism for recovering integration services from OATT customers. In the past two Utah general rate cases the issue of compensation for wind integration costs has been specifically addressed in settlements signed by OCS which include these costs and provide for full credit to customers of any incremental OATT revenue received as a result of the Company's transmission rate case.

The other Company witnesses will address the remaining adjustments proposed in

[1] The OCS approximated the impact of its proposed adjustments on the Utah-allocated EBA balance by applying Utah allocation and sharing percentages, but did not calculate the precise impact including the change to carrying charges.

this case, including an adjustment proposed by UIEC to remove natural gas swap losses, and adjustments for outages at thermal generating units proposed by the Division and OCS.

DC INTERTIE CONTRACT

Q. Please explain the adjustment proposed by Mr. Falkenberg to costs associated with the DC Intertie contract.

A. Mr. Falkenberg argues that costs associated with the DC Intertie should be removed from the Deferral Period because the contract was neither needed nor economic during the period. He argues that the contract must be imprudent since the Company only used it to transfer energy 13 times in the Deferral Period. The impact of the proposed adjustment is a reduction of $358,171 to the EBA balance.

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

A. The DC Intertie contract was executed 18 years ago on May 26, 1994, to provide deliveries of 200 MW of power from Southern California Edison at the Nevada Oregon Border ("NOB") under Amendment 1 to the Winter Power Sales Agreement ("WPSA"). The WPSA was executed on December 14, 1993, and provided up to 422 MW of power to be delivered to the Company's west control area. At the time the WPSA was executed, the Company had sufficient transmission rights to import 222 MW of power into the west control area. The agreement provided that if the Company procured additional transmission rights by June 1, 1993, then it could import the remaining 200 MW to its system. The Company secured the remaining 200 MW of transmission rights by acquiring 200 MW of transmission capacity on the DC intertie. The Company terminated the

WPSA effective January 1, 2002, but the DC Intertie contract remained effective by its terms.

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

A. Yes. The agreement takes advantage of the load diversity between summer-peaking California and the winter-peaking Pacific Northwest. The contract provides a valuable means of securing capacity and energy from California entities to meet retail loads. Loads in California are relatively low in the winter when loads in the Company's west control area and the rest of the Pacific Northwest are at their highest. It is an integral piece of the transmission network in the west control area for meeting load.

The DC Intertie provides firm capacity to the Central Oregon area, an area with increasing commercial load. There are currently two delivery points serving the load, neither of which individually can meet peak load: Summer Lake, which is fed by PACW system energy, and Buckley, which is fed by Colstrip, Hermiston and the DC Intertie. Colstrip and Hermiston are generation sources subject to planned and forced outage events, and the DC Intertie provides access to the California ISO market that can be used to reliably serve load.

Q. Mr. Falkenberg points out that the only energy purchases transacted during the Deferral Period that used the DC Intertie were spot purchases. Is this a cause for concern?

A. No. Mr. Falkenberg's testimony highlights that the transactions utilizing the DC Intertie during the Deferral Period were real-time transactions used to balance the

Company's system. He minimizes the need for these transactions by averaging the hourly megawatts purchased. In reality, the transactions range from 25 MW up to the full 200 MW contract capacity. 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.

Q. Is the DC Intertie contract comparable to the recently expired BPA peaking contract?

A. Yes. The DC Intertie is counted on for reliability purposes and, similar to the expired BPA peaking contract where the Company had the ability to increase its power deliveries in the next hour, the firm access to California ISO at NOB provides the same assurance and additional delivery of power to serve load in the Company's central Oregon load pocket.

Q. Given the above information, do you agree with Mr. Falkenberg's assertion that the DC Intertie contract is not used and useful?

A. No. In fact, Mr. Falkenberg's testimony shows that the contract is used and useful. It seems he is changing the standard to be 'not used and useful enough'.

Q. If the contract costs more than the dollar benefit of the transactions that use the contract, why is it appropriate to include the full costs of the DC Intertie agreement in rates?

A. It is needed to serve load. Furthermore, it would be inappropriate to penalize the

Company by disallowing costs today based solely on a snapshot-view of the energy transferred over a resource that was prudently acquired 18 years ago and which facilitates the delivery of both capacity and energy. By purchasing these transmission rights, the Company purchased assurance that it can reliably serve its retail customers loads. The OCS's proposal based on its limited energy-only view of this contract is similar to arguing that the Company should only be able to recover insurance premiums when it receives proceeds large enough to fully offset the premiums.

Q. Mr. Falkenberg claims the Company stated it would not utilize the type of transactions included in the Deferral Period under normal circumstances. Is this true?

A. No. Mr. Falkenberg cites a data request from a Washington general rate case (UE-100749) wherein the Company described how purchases at the NOB market hub, the same type of transactions included in the Deferral Period in this case, would be treated in a *normalized* GRID study. Because GRID has perfect foresight and represents normalized, not actual, operating conditions, it perfectly optimizes system operations and in that case did not purchase energy at NOB for the test year. A perfectly optimized GRID study assuming normalized conditions will by definition be different than the actual day-to-day operation of the system under real and varying conditions. In fact, the entire purpose of the EBA mechanism is to account for these variations from normalized conditions and allow recovery of actual costs, prudently incurred to serve customers.

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

A. Yes. The 2011 IRP Update relies on market purchases from NOB to serve peak capacity. The Company has shown that it currently utilizes the DC Intertie capacity and plans to continue relying on the contract to transact in the wholesale market in order to serve customer load in the future.

Q. Mr. Falkenberg points out that the Washington Utilities and Transportation Commission ("WUTC") disallowed the costs of the DC Intertie in UE-100749. On what basis were the costs disallowed in that case?

A. The WUTC reasoned that, even if the contract was prudent at its inception, the Company must show that the resource continues to be used and useful. While Mr. Falkenberg quotes a portion of the Washington Commission's order, he omits the portion that makes clear that the Commission decided this issue prior to the Company's modeling change that incorporates the DC Intertie into the GRID model. The Commission's decision expressly relies upon the fact that the contract's capacity was not reflected in GRID in that case.[2] Since that case, however, the Company has updated the GRID topology used in Washington cases to include the DC Intertie contract and access to the NOB market. Mr. Falkenberg also omits that the Idaho and Oregon Commissions rejected this adjustment in 2011.

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

[2] *WUTC v. PacifiCorp*, Docket UE-1000749, Order 06, ¶18 (March 25, 2011).

least the last 5 general rate cases, since Docket No. 07-035-93. Mr. Falkenberg noted that the OCS questioned the prudence of these costs in the 2010 and 2011 general rate cases. These cases were both settled with no finding on the prudence of the DC Intertie. It is important to note that 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.

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

A. Whether it was prudent to acquire the contract 18 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 the Company has demonstrated that it continues to be used and useful today.

CENTRALIA POINT TO POINT CONTRACT

Q. Does Mr. Falkenberg propose an adjustment related to the Centralia PTP wheeling contract?

A. Yes. Mr. Falkenberg proposes that the cost of the Centralia PTP contract be removed from the Deferral Period, which would result in a $555,984 decrease to the EBA balance.

Q. What did Mr. Falkenberg present in support of his adjustment to remove the Centralia PTP contract costs?

A. Mr. Falkenberg claims that the Centralia PTP contract is not adequately utilized and therefore the costs should be removed from the EBA deferral.

Q. Please provide background on the Centralia Point-to-Point wheeling contract.

A. In April 2007, the Company entered into a power purchase agreement with TransAlta with a delivery rate of up to 200 MW per hour for the three-and-one-half year period ending December 31, 2010. The power was delivered to the Company at the C. W. Paul ("Paul") substation located near the Centralia Coal plant in Centralia, Washington. The Company needed to enter into a new wheeling contract with BPA to move the power from the Paul substation to various load pockets in Oregon and Washington because the Company's Formula Power Transmission ("FPT") wheeling contract with BPA was expiring on June 30, 2007. BPA was no longer offering FPT service at that time and required the Company to take new service under a PTP contract at prices specified in BPA's OATT.

Q. Why would the Company choose a five-year term for the Centralia PTP contract?

A. In 2007, the Company elected a five-year term to assure that it had firm rights to serve load during a period of potential change to the resource and transmission portfolio mix and to reduce exposure to the number of parties challenging and competing for the same transmission capacity. At the time of execution, a five-year term was perceived to be the standard term for transmission service agreements that would continually be rolled over, so it discouraged any other party from competing.

Q. How have circumstances changed since the Centralia PTP was executed in 2007?

A. In 2008 the Company took advantage of an opportunity to purchase the Chehalis generating plant, which is located within approximately 10 miles south of the Centralia plant. Purchasing the Chehalis plant produced a significant benefit for the Company's customers, and it included its own transmission rights the Company could use to move the energy from the plant to its Oregon, Washington and California load. The economic analysis supporting the Chehalis acquisition identified that the Centralia PTP contract would no longer need to be extended once it expired in June 2012.

Q. Did the Company use this contract during the Deferral Period?

A. Yes. The Company has been able to redirect a portion the contract capacity to displace incremental wheeling purchases from BPA on other transmission paths, and the Company resold some of the contract rights. These benefits are included in the EBA deferral.

Q. Does Mr. Falkenberg accurately characterize the Company's use of this contract during the Deferral Period?

A. No. First, Mr. Falkenberg references an exchange transaction with TransAlta that expired in 2010 and was not a part of the Deferral Period. Furthermore, he understates the capacity that was redirected (used on other transmission paths) by the Company, with no reference to the source of his calculation. Mr. Falkenberg states the Company redirected 41 MW out of the 638 MW contract capacity, when in fact the Company redirected 122 MW.[3] The Company also reassigned (i.e. sold) an average of 350 MW of capacity to third parties over the deferral period. When all reassignments and redirects are considered, 74 percent of the contract was monetized to the benefit of customers.

Q. Has the Centralia PTP contract now expired?

A. Yes. Effective June 2012 the Centralia PTP contract has expired. During the EBA Deferral Period customers benefitted from the acquisition of Chehalis, and it would be improper to make a one-sided adjustment to remove the costs of the Centralia PTP contract during the final months of its term.

Q. Has the cost of the Centralia PTP contract already been included in Utah rates?

A. Yes. Similar to the DC Intertie contract, the Company's approved rates in Utah have included the Centralia PTP contract for the past 5 years, since Docket No. 07-035-93. Mr. Falkenberg noted that the OCS questioned the prudence of these costs in the 2010 and 2011 general rate cases. These cases were both settled with no finding on the prudence of the Centralia PTP contract. It is important to note that 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.

Q. Why should customers pay for the last few months of the Centralia PTP contract?

A. At the time the Company entered into the Centralia PTP contract in 2007 it viewed purchases from Centralia as a viable long-term source of power to meet its

[3] 34 MW firm and 88 MW conditional firm.

loads especially given the ability to deliver that power directly to five separate locations at four distinct load pockets in its western balancing area. The acquisition of Chehalis in 2008 enhanced the Company's ability to serve load and enabled it to allow the Centralia PTP contract to expire in June 2012 at the end of its term. Any evaluation of prudence must recognize the commercial reality that the Centralia PTP contract would have been difficult or risky to obtain for a period of less than five years. Because the contract was unavailable on a year-by-year basis, it should not be evaluated in that manner for ratemaking purposes. Since the Chehalis acquisition the Company has redirected or reassigned the Centralia PTP capacity to the extent it reasonably could.

LEGAL FEES

Q. Please explain Mr. Falkenberg's proposed adjustment for out-of-period legal fees at Company mines.

A. Mr. Falkenberg proposes to remove legal fees from expenses at Company-owned coal mines that he claims are related to events that took place prior to the Deferral Period. His adjustment would reduce the EBA balance by $61,056.

Q. What evidence did Mr. Falkenberg rely on as the basis of his adjustment?

A. Mr. Falkenberg cited no evidence in his testimony, but provided a workpaper based on the Company's response to data request OCS 2.2. Data request OCS 2.2 asked for a summary of all legal expenses for Bridger Coal Company and Energy West for issues other than fines and citations. In response to OCS 2.2 legal expenses are summarized by the month they were paid, and the date each matter initially arose is identified. Mr. Falkenberg's adjustment removes the amounts during the Deferral Period for each matter identified as initially arising prior to October 2011.

Q. Do you agree that all costs for matters that initially arose prior to October 2011 should be classified as out-of-period costs and removed from the EBA deferral?

A. No. The costs identified as being paid during the Deferral Period are for contemporaneous services. The Company continues to address many legal matters that first arose prior to the Deferral Period, and costs for services rendered continue to be incurred. For example, approximately $167,000 out of the $203,000 total Mr. Falkenberg is proposing to disallow (on a total Company basis) is related to labor negotiations for soon-to-expire collective bargaining agreements. OCS 2.1 identifies that the matter first arose in August 2011, but the negotiations are ongoing and costs continue to be incurred. It is inaccurate to attribute all of these costs as related to a prior period based on the date the matter initially arose. Mr. Falkenberg's proposal implies that, in order for the Company to recover these types of legal expenses, the Company would be required to anticipate all future expenses for a given matter at the time the issue first arises and book them prior to actually incurring such expenses. This is contrary to generally accepted accounting principles and the purpose of the EBA which is designed to allow recovery of actual costs.

Q. Has the Commission addressed recovery of legal expenses in a previous general rate case?

A. Yes. In Docket No. 09-035-23, the Commission recognized that the Company is subject to continuing litigation from events occurring in the past, and agreed that depending on the circumstance, such expenses are legitimate and unavoidable. The Commission further acknowledged a certain level of legal risk is characteristic in the electric utility industry and that settlement and legal expenses are unavoidable.

HUNTINGTON UNIT 2 CONTRACTOR DELAY

Q. Please explain Mr. Falkenberg's proposed adjustment for the Huntington Unit 2 Contractor Delay.

A. Mr. Falkenberg proposes to impute a profit margin on what he claims to be lost generation when an outage on Huntington Unit 2 took 10 days longer than anticipated. His adjustment would reduce the EBA balance by $342,898.

Q. What the basis of his adjustment?

A. Mr. Falkenberg argues that because the Company sought liquidated damages from the contractor performing the work then the delay must have been imprudent and the Company should be penalized by reducing NPC by the market value of the lost energy.

Q. Does Mr. Falkenberg present any evidence that the Company's actions were imprudent?

A. No. Mr. Falkenberg merely points out that the Company sought liquidated damages because a contractor failed to meet its estimated completion date. He argues that, even if the Company prudently managed the relationship with the contractor it should bear the entire cost of the delay. In this instance, completing the outage after the expected completion date in the contract resulted in approximately $262,366[4] of liquidated damages on a Utah-allocated basis being booked as a credit to the capital cost of the overhaul which will be passed back to customers in the form of a lower rate base. Since customers will receive credit for the liquidated damages Mr. Falkenberg's proposal amounts to double dipping.

Q. Does the Company regularly include liquidated damages clauses in its external contractor agreements?

A. Yes. Planned outages are major events involving complex inter-dependent scheduling of internal personnel and external contractors with the goal of rapidly returning units to service. The Company attempts to negotiate the most cost-effective contract that will achieve the project milestones. Liquidated damages clauses are essentially insurance, passing some of the risk of delay from the Company to contractors and are useful in ensuring contractor's objectives are aligned with the Company's. However, as with any insurance, liquidated damages come at a cost in higher overall payments for the contractor services. Therefore, the Company seeks to include liquidated damages at a level which balances the overall risk to the outage schedule against contractor costs.

Q. Is Mr. Falkenberg's proposal balanced?

A. No. Mr. Falkenberg makes a one-sided adjustment to penalize the Company for a schedule delay but does not recommend that an opposite adjustment would be warranted if an outage is completed earlier than scheduled.

[4] $624,682 total Company.

OATT WIND INTEGRATION

Q. What is the recommendation of Mr. Falkenberg in regards to costs associated with wind integration for OATT customers?

A. Mr. Falkenberg recommends excluding costs associated with providing wind integration services to OATT customers from the EBA deferral balance. He argues that the Company should have sought approval to include charges for this service in its OATT, and until it does, the costs should not be charged to retail customers. This adjustment would result in a $228,111 reduction in the deferral.

Q. Please provide background on this issue.

A. 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 a balancing authority area. FERC's *pro forma* OATT, which the Company is required to follow, historically has not permitted mechanisms for charging for this service and has taken a restricted view of the ability to charge transmission customers delivering wind resources differently than other transmission customers. Notwithstanding FERC's restrictions on wind integration charges, customers benefit from the Company being a balancing authority area and the revenues associated with wheeling for wholesale customers collected through the OATT. Customers also benefit by having access to Company-owned transmission for network and PTP service which are necessary to serve load and transact in wholesale markets.

Q. Was this issue already addressed in the 2010 and 2011 general rate case settlements?

A, Yes. The issue of cost recovery for non-owned wind integration was raised in Docket Nos. 10-035-124 (the case that set the Base NPC for the Deferral Period in the EBA) and 11-035-200. The settlements reached in each of these cases acknowledged that the Company had filed a rate case with FERC to modify its OATT, and established a procedure to defer and credit back to customers any incremental revenue received as a result of the pending FERC rate case. The cost of integrating the non-owned wind resources remained in the test period NPC in each case. Now Mr. Falkenberg is proposing an adjustment to the EBA deferral that, despite the previous settlement agreements, removes three months of integration costs that are already included in rates. It would be improper to allow these costs in base rates, but disallow them in the EBA.

Q. Does Mr. Falkenberg acknowledge that the Company has filed with FERC for approval of new rates that will charge OATT customers for wind integration?

A. No. Rather than acknowledge the Company's recent FERC filing, Mr. Falkenberg claims that by October 1, 2011, the Company will have had more than six years since its 2004 IRP to file with FERC to recover wind integration costs from wholesale transmission customers. In fact, the Company filed a rate case with FERC on May 26, 2011, which included updated charges for ancillary services needed to integrate wind, including a new Schedule 3A governing generator regulation and frequency response service. FERC accepted the filing, suspended the filing for five months, and allowed the new rates to become effective subject to refund at the conclusion of the suspension period. The FERC case is currently in the settlement phase, and revenue under the new rates continues to be subject to refund.

Q. Mr. Falkenberg points to decisions from the Washington and Idaho Commission disallowing third-party wind integration costs. How do you respond?

A. Most notably, two of these decisions pre-date the filing of the Company's FERC rate case. In addition, Mr. Falkenberg fails to mention that both this Commission and the Oregon Public Utility Commission have allowed third-party wind integration costs in previous orders. Notably in Docket No. 09-035-23 the Commission acknowledged that the Company did not yet have a FERC-approved tariff and directed the Company to address the issue prior to its next general rate case.

EBA ADJUSTMENTS

Q. Do you have any general comments about the nature of the EBA and the types of adjustments proposed by the OCS in this case?

A. Yes. Three of Mr. Falkenberg's adjustments in this case – his proposals to disallow costs of the DC Intertie, Centralia PTP contract, and non-owned wind integration – are really just repeated attempts to disallow these costs entirely, this time outside of the general rate case process. If the entirety of an issue is again subject to complete review and disallowance in the EBA after it has been addressed in a general rate case, it would render the determination of just and reasonable NPC in a general rate case a meaningless exercise. If an issue has previously been deemed to be reasonably included in base NPC then deviations from the forecast can and ought to be examined in the EBA, and this annual review of actual NPC will identify whether the factors that led to the deviation from base NPC were caused by imprudence on the Company's part. If imprudent actions on the part of the Company result in increases to actual NPC then it would be appropriate to disallow recovery of a portion of the difference. If not, the Company should be allowed to recover the full amount of the difference consistent with the structure and purpose of the EBA.

FUTURE FILING REQUIREMENTS

Q. Have any intervening parties recommended that the Company provide additional information in its future EBA filings?

A. Yes. Specifically, the OCS proposed a list of additional filing requirements consisting of the current filing requirements for the Company's Wyoming Energy Cost Adjustment Mechanism ("ECAM") and an additional requirement to provide root cause analysis reports related to outage events occurring in the Deferral Period. The Division recommended various additional pieces of information should be provided, including: explanations of why specific transactions were made; detail on trading strategies, objectives, and instructions given to its traders; discussion of the interaction between trading strategies and policies; detailed breakdown of actual purchases and sales; details on long-term purchases.

Q. Is the Company willing to provide additional information with its EBA filings?

A. Yes. The Company recognizes the Utah EBA is a pilot program that will continue to evolve as it is implemented, and the Company is willing to work with parties to determine what information would be useful to provide with its EBA filings. Additional information must be 1) relevant to Utah's EBA, 2) available, and 3) not duplicative of filing requirements already approved by this Commission. For example, the Wyoming filing requirements referenced by Mr. Falkenberg include information about renewable energy credits and SO2 emission sales, neither of which are relevant to the Utah EBA. Others require operational data for generating resources, detail of short term firm transactions, and monthly accounting for wheeling expenses and revenues, all of which is already provided as part of the Utah EBA filing requirements. Root cause analyses could only be provided if they have been completed by the filing of the EBA application each March.

Q. Do you agree that the list of information identified by the Division should be included as filing requirements in future EBA filings?

A. No. All but two of the issues listed in Mr. Hahn's testimony are not requests for data. Many are requests for explanations regarding the nature of the Company's business. Since the filing of his direct testimony where he recommended the list of additional information, the Company has provided explanations regarding these types of issues (e.g. why certain trades are made) and explained to Mr. Hahn the type of informational archives that are available. For these types of issues it would be more appropriate to obtain additional information as needed (i.e. for samples of transactions) in future filings through the discovery process. The remaining two items – a detailed breakdown of actual purchases and sales and details on long-term purchases – were provided in this case, either in discovery or with the original filing. Details on long-term firm purchases and sales are best obtained through the individual contracts, and new or modified contracts of this nature are provided under Wyoming ECAM filing requirement 4.

Q. Does this conclude your testimony?

A. Yes.