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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-11-12**
MOUNTAIN POWER FOR	)	
APPROVAL OF CHANGES TO ITS	)	**Direct Testimony of Gregory N. Duvall**
ELECTRIC SERVICE SCHEDULES	)	**Redacted**
AND A PRICE INCREASE OF $32.7	)	
MILLION, OR APPROXIMATELY	)	
15.0 PERCENT	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-11-12

May 2011

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

A. My name is Gregory N. Duvall. My business address is 825 NE Multnomah, Suite 600, Portland, Oregon, 97232. My present position is Director, Net Power Costs.

Qualifications

Q. Briefly describe your education and business experience.

A. I received a degree in Mathematics from University of Washington in 1976 and a Masters of Business Administration from University of Portland in 1979. I was first employed by PacifiCorp in 1976 and have held various positions in resource and transmission planning, regulation, resource acquisitions and trading. From 1997 through 2000 I lived in Australia where I managed the Energy Trading Department for Powercor, a PacifiCorp subsidiary at that time. After returning to Portland, I was involved in direct access issues in Oregon and was responsible for directing the analytical effort for the Multi-State Process ("MSP"). Currently, I direct the work of the load forecasting group, the net power cost group, and the renewable compliance area.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. I present the Company's proposed net power costs ("NPC") based on actual data for the 12-month period ending December 2010 with known and measurable changes through December 2011 in support of the Company's 2011 test period in this case. Specifically, my testimony:

- Addresses the specific adjustments related to the GRID model described in the section for net power costs of the Commission Order No. 32196 ("2010 Rate Case Order") in the Company's 2010 general rate case, Case No. PAC-E-10-07 ("2010 GRC").

- Describes the major cost drivers in the 2011 NPC.
- Presents the Company's updated wind integration charges based on the verifiable 2010 Wind Integration Study and explains how they are incorporated in the current filing.

Summary of Net Power Costs in the Current Filing

Q. What are the normalized net power costs for the test period?

A. The normalized NPC for the 12 months ending December 2011 are approximately $82.8 million on an Idaho allocated basis, or $1.312 billion system-wide as presented in Exhibit No. 35. The allocation of total Company NPC to Idaho is presented in Exhibit No. 2 in Company witness Mr. Steven R. McDougal's direct testimony.

Q. How do proposed NPC compare with the NPC that the Commission authorized in the Company's last general rate case, Case No. PAC-E-10-07? (the "2010 General Rate Case")

A. The NPC authorized in the 2010 General Rate Case were $1.025 billion on a total Company basis or $66.0 million on an Idaho allocated basis. On a total Company basis, NPC have increased approximately $287 million from $1.025 billion to $1.312 billion. Idaho's allocated portion of NPC in the current filing is approximately $16.8 million higher than the NPC currently included in customers' rates.

Q. Why have NPC increased?

A. To understand why NPC have increased, I present Table A which illustrates the changes in NPC by category:

Table A

Comparison of Idaho 2011 GRC to Idaho 2010 GRC			
Category	Change in Costs Favorable	Change in Costs Unfavorable	Change in MWh
Total Special Sales For Resale		($347,220,266)	(4,518,537)
Total Purchased Power & Net Interchange		($1,826,473)	3,536,077
Total Coal Fuel Burn Expense		($12,281,065)	(3,434,792)
Total Gas Fuel Burn Expense	$85,607,243		(3,750,177)
Wheeling and Other		($11,309,616)	(151,448)
Net system Load			718,186
Total Net Power Costs	$85,607,243	($372,637,421)	0

As shown in Table A, the increase in NPC is driven largely by the unfavorable change in revenues from sales for resale (wholesale sales), which is partially offset by a favorable change in natural gas fuel burn expense. The decline in wholesale sales revenues is primarily driven by a drop in market prices which are 30 percent lower in the current filing as compared to the 2010 GRC filing. In addition, the Company had significantly less volume of wholesale sales and thermal generation because: 1) low market prices make it more economic at times to displace thermal units with purchases from the market; and 2) more capacity from the thermal units is needed to provide reserves due to the 2,183 MW of wind generation in the Company's Balancing Authority Areas ("BAA") at the end of 2010.

Q. Have you included the results of its most recent wind integration study into the current filing?

A. Yes. In response to Order No. 32196 from the 2010 GRC, I am sponsoring a wind integration study ("Wind Study") that verifiably depicts the Company's wind integration costs. The inclusion of these costs is consistent with Order No. 32196, where the Commission stated: "We are not happy with this end result, because we believe these integration costs belong in base rates."[1] The Wind Study results showing a regulation reserve requirement[2] of 533 megawatts ("MW") are further supported by the fact that the Company carried 629 MW of regulation reserves in 2010. Lastly, instead of the dollar per megawatt-hour ("MWh") adder used in the last case, the Company improved its modeling and reflected the Wind Study's 533 MW regulation reserve requirement within the Generation and Regulation Initiative Decision ("GRID") model, resulting in an accurate depiction of how the Company's system incurs costs associated with wind generation resources in the test period.

Q. Please briefly explain the change in GRID associated with the Company's 2010 Wind Study.

A. The results of the Wind Study showed that on average the Company would need to carry reserves for the intra-hour variations of load and wind of 533 MW. This is an increase of approximately 267 MW over the 2010 GRC filing, which included regulation reserves to address load variability, but did not include any additional regulation reserves to manage the 2,183 MW of wind in the Company's BAAs, and instead addressed this reserve cost as an incremental line item charge of $6.50/MWh. The $6.50/MWh charge for reserves in the 2010 GRC filing has been eliminated and replaced in the GRID model by the total wind net load

[1] Case No. PAC-E-10-07, Order No. 32196 page 30, Issued February 28, 2011.
[2] "Regulation requirement" or "regulation reserves" consist of reserves available in 10 minutes (referred to as regulating reserves) and reserves available in 60 minutes (referred to as load following reserves).

reserve requirement determined in the Wind Study. The GRID model then calculates the costs associated with the regulation reserves by backing off generation to supply those reserves that would otherwise be used to serve load or generate margins to reduce net power costs. These additional reserve requirements are one contributor to the reduction in generation seen in Table A of the Company's coal and natural gas-fired resources. I will discuss this in more detail later in my testimony.

Q. How will the normalized NPC approved by the Commission in this proceeding be used for setting retail rates in Idaho?

A. The approved normalized NPC from this proceeding will establish the level of NPC included in base rates and will set the base NPC for purposes of the Energy Cost Adjustment Mechanism ("ECAM") and will be trued-up to actual NPC consistent with the mechanics of the ECAM.

Determination of NPC and Model Inputs and Outputs

Q. Please explain NPC.

A. NPC are defined by the NPC report included as Exhibit No. 35 and include the sum of fuel related expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue.

Q. Please explain how the Company calculates NPC.

A. NPC are calculated using the GRID model. GRID is a production cost model that simulates the operation of the Company's power system on an hourly basis.

Q. Is the Company's general approach to the calculation of NPC using the GRID model the same in this case as in previous cases?

A. Yes. The Company used the GRID model in its last rate filing in Idaho.

Q. Is the Company using the same version of the GRID model as used in the 2010 General Rate Case?

A. Yes.

Q. What inputs were updated for this filing?

A. The system load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, market prices for electricity and natural gas, fuel expenses, characteristics of the Company's generation facilities, normalized planned outages and normalized forced outages of the Company's generation resources are updated for this filing. I address some of these components later in my testimony along with changes to include transactions with the Cal ISO and changes in the modeling of market caps.

Q. What reports does the GRID model produce?

A. The major output from the GRID model is the NPC report. This is attached to my testimony as Exhibit No. 35. Additional data with more detailed analyses are also available in hourly, daily, monthly and annual formats by heavy-load hours and light-load hours.

Q. Has the Company changed its modeling of normalized hydro generation?

A. No.

Adjustments Identified in the Commission Order

Q. What adjustments did the Commission direct the Company to make in Order No. 32196?

A. In Order No. 32196, the Commission directed the Company to make adjustments for Normalization of Call Option Contracts, Wind Integration Costs, and Cal ISO Wheeling & Service Fees. The Normalization of Call Option Contracts the contracts that the Company has with Black Hills Power ("Black Hills") and the Sacramento Municipal Utility District ("SMUD").

Q. How does the Company model the normalization of call option contracts in the current filing?

A. For the contracts with Black Hills and SMUD, the Company modeled the energy delivery using a three-year historic average, as directed by the Commission in Order No. 32196.

Q. Please discuss the Commission's decision on wind integration costs?

A. In its order, the Commission denied the inclusion of wind integration costs in the Company's base net power costs, stating that:

> [n]o party to this case denies that wind integration costs are real costs; the consensus, however is that they cannot be readily forecast with accuracy, calculated or verified... The Company, we find, has not presented the Commission with a verifiable study depicting its wind integration costs.[3]

Q. Has the Company updated its modeling approach in GRID to more accurately calculate wind integration costs?

A. Yes. As part of its 2011 Integrated Resource Plan, the Company conducted an

[3]Case No. PAC-E-10-07, Order No. 32196, page 30 issued February 28, 2011.

extensive Wind Study that assessed the impact of integrating wind generation into its resource portfolio. The Wind Study is provided as Exhibit No. 36. In the current filing, the Company has reflected the results of the Wind Study, which I will discuss in more detail later in my testimony.

Q. Has the Company included wind integration costs for wholesale transmission customers in its current NPC filing?

A. Yes. The Company is required to integrate wholesale customers in a non-discriminatory manner under federal law pursuant to the Company's Open Access Transmission Tariff ("OATT"). The OATT does not allow the Company to charge for these integration costs separately from other charges under the OATT. However, customers are benefited by the Company being a balancing area authority and receiving wheeling revenues from wholesale customers which are applied as a credit against the cost of providing retail service. On or before June 1, 2011, the Company will file a wholesale rate case with the Federal Energy Regulatory Commission ("FERC") to update its wholesale transmission rates. As part of that filing, the Company is requesting a new Schedule 3A which, if approved by FERC, will allow the Company to charge generators that do not have load in the BAA for regulation reserves.

Q. How does the Company respond to the Commission's decision on Cal ISO fees in the 2010 Rate Case Order?

A. The Commission's decision was made based on the fact that the Company's net power cost calculations in that case did not include transactions explicitly with the Cal ISO as the counterparty. The Commission indicated that transaction data should have been provided if the Company intended for the Cal ISO fees to be a continuing expense. To address this concern, the Company added Cal ISO transactions to the GRID model. The transactions with the Cal ISO are a necessary part of the Company's activities to serve its load obligation and balance its system. Because of its diversity and liquidity, the Cal ISO is an important counterparty for the Company when approaching time of delivery, which is also a fact that Monsanto agreed to in Mr. Mark T. Widmer's testimony: "Historical records reveal that most of the transactions with the Cal ISO as a counter party are incurred shortly before or on the actual day of delivery."[4] As a result, the Company has modeled expected sales and purchase transactions with the Cal ISO based on historical averages.

Q. Please explain how such transactions are modeled in the Company's current filing?

A. Based on data in the same four-year historical period used to determine the market caps, the Company calculated the average amount of energy sold to and purchased from the Cal ISO on a monthly basis and by heavy load hour ("HLH") and light load hour ("LLH"). The executed short term firm transactions that the Company included in the filing are through the end of March 2011. For the remainder of the test period, the Company modeled expected transactions with Cal ISO at three major points of delivery based on historical information: Four Corners ("4C"), California Oregon Border ("COB") and Mona. Because these are expected transactions, similar to "System Balancing" sales and purchases, they

[4]See Docket No. ID PAC-E-10-07, Confidential Corrected Direct Testimony of Mark Widmer, Page 24, Lines 1-2.

are grouped with the system balancing sales and purchases as modeled by GRID at corresponding points of delivery. Together with these transactions, the Company included the expected Cal ISO wheeling fees and service fees.

Major Cost Drivers in the 2011 NPC

Q. Please identify the major cost drivers in the 2011 NPC.

A. As identified in my summary, the primary cost driver is the reduction in wholesale sales brought about by lower market prices and reduced thermal generation offset in part by a reduction in natural gas fuel expense. Other drivers include the following:

- An increase in retail sales;
- Expiration of a number of long-term wholesale power contracts;
- Increased coal expense; and
- An increase in the wholesale power and wind integration rates of the Bonneville Power Administration ("BPA").

Finally, in this section I describe the treatment of the Monsanto contract and changes to modeling of market caps.

Q. Please describe the impact of lower wholesale sales volumes and revenues.

A. Volumes of wholesale sales are down by 4.5 million MWhs as shown in Table 1. This reduced volume of wholesale sales is estimated to increases NPC by $157 million. In addition, wholesale electricity market prices are approximately 30 percent lower than those included in the 2010 GRC. Even with no change in volume, wholesale sales revenues would be approximately $190 million lower due to changes in market prices alone.[5] The reduction in wholesale sales revenues is offset in part by lower natural gas fuel expenses in the current filing of $86 million. Although purchased power prices are also lower, the overall purchased power expense increased by just under $2 million due to increased volumes of 3.5 million MWhs.

Q. **What are the major drivers to the reduced volume of wholesale sales?**

A. The primary drivers to reduced wholesale sales volume include reduced thermal generation, increased retail loads, and expiration of several long-term wholesale power contracts including purchase and sale exchanges.

Q. **Why is thermal generation lower in the current filing as compared to the 2010 GRC?**

A. As shown in Table A, coal fired generation is lower by 3.8 million MWh and natural gas fired generation is lower by 3.5 million MWh. The primary drivers for this reduction are economic displacement and increased reserves modeled in GRID. Economic displacement of thermal units is a consequence of market price reductions that result in a higher frequency of times when thermal generation is uneconomic to operate. Thermal generation is also lower due to the explicit modeling of regulation reserves in GRID, which requires thermal generation to be backed down to carry the necessary regulation reserves required to integrate load and wind generation variability and maintain reliability.

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[5] 19.2 million megawatt-hours ("MWh") at prices that are approximately $9.9/MWh lower.

REDACTED

Q. Please explain how the drop in wholesale electricity market prices and natural gas prices affects how the GRID model holds reserves.

A. The change in the wholesale electricity market prices is greater than the drop in natural gas prices which reduces the amount of time the Company's natural gas-fired resources are economically dispatched. When the GRID model determines that it is uneconomic to dispatch a gas-fired resource and that resource was carrying reserves, then that reserve carrying requirement is shifted to other resources including coal. For example, if Lake Side I is not dispatched because it is uneconomic to do so, it is no longer available to hold reserves, therefore the model will hold reserves on the next available resource, which would show as a decline in generation of that resource due to the fact that it is now holding reserves rather than being able to generate and serve load or sell into the wholesale market. This decline in generation associated with reserve holding is apparent in the reductions in Table A of the Company's coal and natural gas-fired resources.

Q. Do the NPC in this filing reflect increases in coal costs since the 2010 GRC?

A. Yes. As shown in Table A, NPC are higher by approximately $12 million even though generation from coal units has declined by 3.4 million MWhs. Notwithstanding this decline in the volume of coal generation, increased costs of third-party coal supply and transportation agreements, and cost increases at the Company's captive mines are driving these costs. Details on coal costs are provided in the direct testimony of Company witness Ms. Cindy A. Crane.

Q. What are the major changes to power contracts in the test period?

A. The contracts that have expired or will expire, change or are new in the test period include:

- On June 30, 2011, the exchange contract between the Company and the Alcoa Power Generating Inc. ("APGI") for approximately 100 MW of capacity from the Rocky Reach project expires. Under this contract, the Company receives energy during peak periods and returns energy during off-peak periods.
- On October 31, 2011, the contract between the Company and the Chelan Public Utility District ("Chelan PUD") for generation from the Rocky Reach project expires. Power purchased by the Company under this contract is priced at the embedded cost of the project.
- On August 31, 2011, the contract between the Company and the Bonneville Power Administration ("BPA") for 575 MW of capacity expires. Under this contract, the Company receives energy during peak periods and returns energy during off-peak periods. In addition, power received under this contract is delivered directly to a variety of the Company's load pockets in the western area at the Company's discretion.
- On September 30, 2011, the contract between the Company and the Grant Public Utility District ("Grant PUD") for displacement generation expires, which is priced at BPA's Priority Firm Power ("PF") rate.
- On January 1, 2011, the amount of sales to the Public Service Company of Colorado ("PSCol") reduces per the contract terms, which is a legacy sales contract at relatively high contract prices.

Q. Does the filing reflect an increase in load that impacts NPC?

A. Yes. This filing reflects an increase of approximately 1.2 percent in the total Company system load compared to loads reflected in the 2010 GRC. All else held constant, increased load increases NPC, which in this case increased NPC by approximately $15 million. The system load in this filing is the actual load in 2010, adjusted for temperature.

Q. What assumptions did the Company make in regard to the power rates and transmission rates proposed in the current rate cases of the BPA?

A. The BPA rate cases will determine the new rates for the fiscal period beginning in October 2011. Given the current proposals made by BPA, the Company assumes that the wheeling expenses of the Company's transmission contracts with BPA would not change in the new BPA rate effective period that begins in October 2011. In the current filing, the Company has incorporated the proposed wind integration charge at $1.32/kilowatt(kW)-month beginning in October 2011, which is a change from the current $1.29/kW-month. The Company has also incorporated the impact of BPA's proposed charges for reserves and power.

Q. Does the Company expect to update the expenses related to all contracts with BPA?

A. Yes. The Company will update its NPC on rebuttal with the final decision of the BPA rate cases currently expected in July 2011, or when better information becomes available.

Q. How is the price of the contract with Monsanto for interruptible products reflected in the test period?

A. Given the interim agreement with Monsanto, the previous contract price at $[redacted]/kW-month is effective through April 28, 2011. Beginning on April 29, 2011, the contract price is equivalent to $[redacted] million per year as authorized by the Commission or $[redacted]/kW-month for 162 MW for a term ending May 31, 2011. We expect that should the Company and Monsanto need additional time to complete a long term agreement, then this interim agreement will be extended.

Q. Please describe the Company's change to the modeling of market caps?

A. To address the issues around the Company's assumption about market caps during the graveyard hours, the Company reviewed its overall approach to market caps and developed a more comprehensive approach to modeling market depth. Instead of specifying market depth for graveyard hours only, the Company now proposes to specify market depth during all hours, segregated by HLH and LLH periods. The Company believes that a market may be liquid, but this liquidity does not translate into unlimited sales at any time of day or night. Due to load requirements and transmission constraints in the region and static assumptions about market prices in GRID, among other things, the Company may not be able to sell all its economic generation to the markets. The market depths for wholesale sales in GRID are now determined based on the historical short-term firm transactions during the same 48-month period on which availability of the thermal generation is based. The depths are then reduced by the quantity of short-term firm transactions that the Company has included in the normalized NPC study for the test period in all sales markets.

Wind Integration Costs

Q. Please discuss the Company's approach to calculating wind integration costs?

A. The remainder of my testimony discusses the Company's treatment of wind integration costs. As part of the 2011 IRP, the Company performed an extensive Wind Study on the impact of integrating wind generation into its resource portfolio. The Wind Study was completed after reviewing the issues and concerns raised by various parties in Idaho and other jurisdictions, such as whether the wind integration costs should be studied independent of load, the amount of additional reserves needed to integrate the wind generation and what resources should be utilized to serve the additional reserve requirements.

Q. Please describe the Company's Wind Study.

A. The purpose of the Wind Study is twofold. First, the Wind Study quantifies how wind generation affects the amount of additional reserves needed to maintain reliability. Second, the Wind Study determines the costs of integrating wind generation by measuring how system costs change with changes in operating reserve demand, and by measuring how system costs are affected by daily system balancing practices.

Q. What are the additional reserve requirements?

A. The Wind Study identified additional regulation reserve requirements in two categories: regulating services that deal with load and wind variability in 10-

minute intervals, and load following services that deal with load and wind variability over hourly time intervals. Both services respond to the up and down variations of wind generation. That is, the additional reserve requirements to integrate wind generation into the Company's resource portfolio consist of regulating up, regulating down, load following up and load following down. The Wind Study performed analyses of additional reserve requirements for load only (excluding wind generation) and for wind net of load (including wind generation), based on historical 10-minute data for the Company's system.

Q. In order to provide for this additional regulating and load following requirement, what changes in operations has the Company had to make?

A. Given the size of the wind portfolio, and the possibility of rapid variations in wind generation, the Company has had to commit its gas-fired generation units to be able to quickly respond to the magnitude of changes. At times, this "must-run" operation requires gas-fired generation units to run when it would otherwise be uneconomic to do so, thereby adding to the wind integration costs.

Q. How did the Company incorporate the results from the Wind Study?

A. The amount of the total regulation reserve requirements to meet system variability is 337 average MW and 196 average MW for the east and west sides of the Company's system, respectively, for a total of 533 MW system-wide. The 533 MW is an increase of approximately 267 MW from the 2010 GRC, which only captured regulation reserve requirement for load variability, but did not include any incremental reserves for wind variability.

Q. Did the Company also change how it modeled its thermal resources in order to accommodate the additional reserve requirements in GRID?

A. Yes. In order to accommodate the increase in regulation reserve requirements as identified in the Wind Study, the Company modeled the Currant Creek unit, and Gadsby units 4, 5 and 6 as must-run units that are not subject to the logic of being committed to run only when economic. Modeling these resources as must-run is consistent with the Wind Study, in which the Company concluded that it was appropriate in order for the model to be "reasonably aligned with actual operational characteristics of the east-side gas plants…"[6]

Q. Does the Company believe that by reflecting the additional reserve requirements, instead of reflecting a dollar per MWh charge, it more accurately reflects the costs of integrating wind into its system?

A. Yes. Allowing the GRID model to optimize the system, taking into consideration the additional reserves required to integrate the level of wind that is included in the GRID model, more accurately reflects the real-time operation of the system.

Q. Does this change in how the Company has modeled its wind integration costs address the Idaho Commission's concern that it is over recovering its costs associated with wind integration?

A. Yes. The Wind Study is a verifiable study of the Company's costs associated with integrating wind generation into its systems. It clearly demonstrates the additional requirements for regulation reserves, and the requirement to have sufficient must-run thermal resources online to provide a quick response to the significant

[6]See Exhibit No. 36, the Wind Study, Page 25.

variations in wind generation. The level of reserves needed to meet variations in load and wind identified in the Wind Study are supported by actual reserves held by the Company for this purpose in 2010. There is no reason to believe that the Company will over recover its costs associated with wind integration. Customers are further protected by the Energy Cost Adjustment Mechanism ("ECAM").

Q. Did the wind study also identify additional costs associated with day-ahead forecast errors for wind and load?

A. Yes. Using the results of the Wind Study, the Company modeled $0.72/MWh for day-ahead forecast errors, or system balancing costs in the NPC study.

Q. Did the Company reasonably model the Wind Study results in GRID for the current filing?

A. Yes. The results from GRID reasonably reflect the impact of integrating wind generation into the Company's portfolio. The Wind Study addressed all the issues raised by various parties in Idaho and other states, such as reserve requirements being modeled within GRID, the requirements for wind generation being considered net of load, studies supporting the impact of integrating generation from wind facilities, and the quality of data used to prepare the study. However, given the limitation of data inputs to the normalized studies, I believe that the GRID-modeled impact of integrating wind resources may understate the real costs. For example, the GRID model uses expected wind profiles of the wind projects which lack the variability reflected in the actual operations of the wind projects.

Q. Have you validated the Wind Study against the Company's actual experience?

A. Yes. The Company computed the actual reserves carried during 2010 to meet spinning and supplemental contingency reserves, and regulation reserves from recorded data. The actual regulation reserves carried on the system during 2010 was 629 MW. This is 96 MW higher than the 533 MW calculated in the Wind Study and modeled in GRID, thereby validating the Wind Study results as reasonable, if not low.

Q. Does the Company include system balancing costs for the non-owned wind projects and for projects located in the BPA's balancing area?

A. No, the normalized NPC in the current filing do not include system balancing costs for the wind projects located in the Company's balancing areas that the Company neither owns nor purchases the output. This is based on the assumption that the entities that own and/or operate those wind projects will balance their own system prior to handing over their generation schedule to the Company. However, following that same logic, the normalized NPC include system balancing costs for projects located in BPA's balancing area: Leaning Juniper and Goodnoe Hills.

Q. Has the Company included wind integration costs for the non-owned wind projects located within its balancing area in this filing?

A. Yes. As discussed in the 2010 GRC, the Company is required to provide wind integration service to wholesale customers under federal law; the Company's Open Access Transmission Tariff (OATT) does not allow the Company to charge