**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 N.E. Multnomah, Suite 600, Portland, Oregon, 97232. My present position is Director, Long Range Planning and 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 Pacific Power 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, was responsible for directing the analytical effort for the Multi-State Process ("MSP"), and currently direct the work of the integrated resource planning group, the load forecasting group, and the net power cost group in the Company.

**Summary of Testimony**

**Q. Will you please summarize your testimony?**

A. I present the Company's proposed net power costs for the test period of 12-month ending June 2010. Specifically, my testimony:

- Describes the changes in the Company's net power costs
- Addresses several issues raised but not resolved in Docket No. 08-035-38,

including:

- An update on the issues from Docket No. 08-035-38 set for workshops and additional review under the stipulation in that case
- Modeling of the sales contract with the Sacramento Municipal Utility District ("SMUD")
- Scheduling of planned outages
- Value of startup generation
- Modeling of short term firm transmission

- Describes modeling enhancements addressing hydro resources
- Presents the Company's updated wind integration charges

**Summary of Net Power Costs**

**Q. What are the forecasted normalized system-wide net power costs for the 12-month period ending June 2010?**

A. The Company's total forecasted normalized net power costs for the test period are approximately $999 million on a total company basis, and $410 million allocated to Utah.

**Changes in Net Power Costs**

**Q. Please describe the changes in net power costs forecasted in this case as compared to net power costs in rates.**

A. Based upon the Stipulation in Docket No. 08-035-38, system net power costs in rates are approximately $1.030 billion (reflecting the stipulated $7.4 million reduction from the Company's rebuttal position on a Utah allocated basis). The Company's forecast net power costs in this case are lower by $31 million. On a dollar-per-megawatt hour basis, however, proposed net power costs and net power costs in rates are essentially unchanged, with a cost of $17.22 per megawatt hour in rates and a cost of $17.15 per megawatt hour proposed in this filing.

**Q. What is the major driver of the decrease in total net power costs in this case?**

A. As can be discerned from my previous response, the major driver of the decrease in net power costs is reduction in the Company's system load. The system load in the current filing is about 1.6 million megawatt-hours (about 2.8 percent) lower than in Docket No. 08-035-38, which reduces the net power costs by about $70 million. Dr. Peter C. Eelkema's testimony explains the changes in the forecast of system load. Other factors driving net power costs downward in the test period include the reduction in the market prices for electricity and natural gas, the expiration of relatively high-priced contracts with certain qualifying facilities, and two new wind resources, High Plains and McFadden Ridge.

**Q. Are costs related to other factors increasing, offsetting some of these forecast cost decreases?**

A. Yes. The factors that are driving net power costs increases in the test period include the expiration of low-cost, long-term firm power purchase and high-priced, long-term sales contracts, increased firm wheeling expenses, and increased wind integration costs.

**Q. How do expiring power purchase and sales contracts impact net power costs?**

A. The cost of the replacement power could be higher or lower, depending on whether the price of the expired power purchase contract was below or above the market prices. Likewise, the revenue credits of additional wholesale sales could be lower or higher, depending on whether the price of the expired power sales contract was above or below the market prices.

**Q. Please highlight some of the key contract changes in the net power costs forecast.**

A. In November 2009, the nearly 50 year old contract between the Company and the Grant Public Utility District ("Grant PUD") under which the Company purchased a share of the output of the Wanapum hydro-electric project expires. Because this contract was priced at the cost of the Wanapum project, which is significantly below current market prices, net power costs in the test period are higher due to higher costs of the replacement power. The cost increase from this contract is almost fully mitigated by the increase in revenues from the Reasonable Portion of the contract with Grant PUD. Also, this filing reflects the expiration of the sales contract with NV Energy ("Sierra Pacific") and the sales contract with Salt River Project, and a reduction in the energy take of the sales contract with the Public Service Company of Colorado ("PSCol") per the contract terms. The sales price under these contracts exceeds the current market price. The combined impact of these three contracts increases net power costs by approximately $9 million on a total Company basis.

**Q. What are the primary reasons for the increase in firm wheeling expenses?**

A. Wheeling expenses increased due to expiration of a low priced formula power transfer ("FPT") wheeling contract with the Bonneville Power Administration ("BPA"), which will be converted to a higher priced BPA point-to-point ("PTP") contract. BPA is eliminating FPT contracts when they expire. Also, the

Company has received a written notice from Idaho Power Company to modify the wheeling contract associated with delivering generation from the Jim Bridger plant to the Company's load areas. The expense related to the modification of this wheeling contract is estimated to increase by about $2 million. In addition, the wind integration charges paid to BPA are now included in the wheeling expenses. The total changes in wheeling expenses result in an approximate $12 million increase in net power costs on a total Company basis.

**Q. Why are the Company's wind integration charges increasing?**

A. The Company just completed a comprehensive study of its wind integration costs, which have increased as more wind resources are added to the system. The last section of my testimony addresses this issue in detail.

**Determination of Net Power Costs**

**Q. Please explain net power costs.**

A. Net power costs are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue.

**Q. Please explain how the Company calculates net power costs.**

A. Net power costs are calculated for a future test period based on projected data using the GRID model. GRID models net power costs on an hourly basis.

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

A. Yes. The Company has used the GRID model in its last several rate cases in Utah.

**Q. Is the Company using the same version of the GRID model as used in Docket No. 08-035-38?**

A. Yes.

**GRID Model Inputs and Outputs**

**Q. What inputs were updated for this filing?**

A. The net system load, wholesale sales and purchase power expenses, wheeling expenses, market prices for natural gas and electricity, fuel expenses, hydro generation, thermal capacity, heat rates, thermal planned maintenance and outages inputs were updated for this filing.

**Q. What reports does the GRID model produce?**

A. The major output from the GRID model is the Net Power Cost report. This is attached to my testimony as Exhibit RMP___(GND-1). 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. Consistent with the Commission's order in the Company's 2007 general rate case, Docket No. 07-035-93, has the Company checked the dispatch of the gas-fired plants, the duct firing units and call options to ensure the prudent dispatch of its resources in the GRID model?**

A. Yes. The Company checked all the gas-fired resources and call option contracts in its net power costs model to ensure economic dispatch on a monthly basis, the approach approved by the Commission in Docket No. 07-035-93. In addition, the Company checked the duct firing units of the gas-fired plants to ensure that the duct firing units do not run when their corresponding underlying combined-cycle unit is not running.

**Q. Do you believe that the GRID model appropriately reflects the Company's forecasted net power costs over the test period?**

A. Yes. The GRID model reasonably simulates the operation of the Company's system load and resource portfolio consistent with the Company's operation of its system including operating constraints and requirements.

**Issues Raised but not Resolved in Docket No. 08-035-38**

**Status of Issues Set for Additional Review in the Stipulation in Docket No. 08-035-38**

**Q. As part of the Stipulation in Docket No. 08-035-38, the Company agreed to request that the Commission open an investigation into its natural gas hedging activities. Did the Company make this request?**

A. Yes. On April 9, 2009, the Company requested that the Commission open a docket to study the natural gas price risk management policies and procedures of the Company and schedule a technical conference to allow interested parties to participate. The Commission issued a schedule on May 12, 2009, which set technical conferences for May 18, 2009 and June 3, 2009.

**Q. Did the parties to the stipulation also agree to meet and review the issues around the modeling of planned outages?**

A. Yes. The Company met with representatives from the Division of Public Utilities and the Committee of Consumer Services on April 13 and April 23, 2009, on this issue. Unfortunately, because the Company's modeling of planned outages is being contested in open dockets in other jurisdictions, it was difficult to fully address and resolve the issues. The Company remains open to continued dialogue with the Utah parties on this issue if this impediment clears or dissipates.

**Q. Did the parties agree to address the issue of filing updates in the rulemaking on SB 75?**

A. Yes. However, it is uncertain whether the issue will be addressed in the rulemaking as parties may view the issue of filing updates as outside the scope of that docket.

**Q. What is the Company's position on updates to the net power costs in this case?**

A. In Docket No. 07-035-93, the Commission rejected the Company's proposal to update the forward price curve (which would have increased net power costs) but allowed updates proposed by other parties (which decreased net power costs). Based upon this one-sided result, the Company's current position is that all post-filing updates should be disallowed, unless the Commission permits updates on a symmetrical basis.

**Q. Has the Company proposed an energy cost recovery mechanism (ECAM) in Utah?**

A. Yes. This filing is now pending in Docket 09-035-15. The Company expects this case and Docket 09-035-15 to proceed concurrently. If the Company's ECAM is approved, the Company expects that this case will establish the net power costs baseline for purposes of operation of the ECAM. As a practical matter, the approval of the ECAM may obviate the issue around whether to allow post-filing updates to net power costs.

**Q. Are there unresolved issues from Docket No. 08-035-38 that materially impact the net power cost calculation in the current proceeding?**

A. Yes. These include the following issues:

- Modeling of the SMUD sales contract
- Scheduling of planned outages
- Value of the startup generation
- Modeling of short term firm transmission

**Q. Please discuss the modeling of the SMUD contract.**

A. The Commission's 2007 rate case Order directed the de-optimization of the modeling of the SMUD contract in the Company's normalized net power cost studies. In rebutting the Committee's further de-optimization of other contracts, the Company took a closer look at the SMUD "normalization." It turns out that the original method only looked at the firm power portion of the SMUD contract, while the contract also allows SMUD to take provisional power. When both of these are modeled together, the SMUD contract showed that the shape proposed by the Committee in the 2007 general rate does not comport well with the historic take by SMUD under the contract. As a result, the Company recommended that the Commission return to normal, optimized modeling for the SMUD contract. In determining the Company's net power costs for this current proceeding, the SMUD contract is optimized per the terms of the contract.

**Q. What is the Company's approach to modeling planned outages in this case?**

A. In GRID, the length of the planned outages is based on 48-month historical data, and the planned outages are scheduled in a way that all plants are on planned outage during the test year, even though this is not the actual practice. The planned outages are scheduled on a control area basis, and within certain windows to take advantage of the market conditions and limit the number of major units on planned outage at one time. Due to the length of the planned outages, however, it may be necessary for several plants to be offline simultaneously.

**Q. Why doesn't the Company use the historical schedule of the planned outages in its normalized net power cost calculations when it uses historical length of the planned outages?**

A. The Company plans for major overhaul of units in a four-year cycle in general. For major overhauls, the outage time is longer. The major overhauls of various units are scheduled at different times and in different years to minimize any significant impact to generation levels and reliability of the system. In addition, the timing of the historical planned outages is impacted by the composition of the resources at the time, market conditions at the time and load at the time. Because of the need to normalize the costs of this four-year cycle into a single test year, the actual historical schedule cannot be used in ratemaking without some modification. Forcing the scheduling of the planned outages in a single test period to match the timing of the schedules in every one of those four historical years will lead to an unreasonable amount of resources being scheduled offline at the same time.

**Q. Please give an example of the unreasonable amount of resources being offline if the timing of planned outages in the test period were to be based on the historical schedules.**

A. A thermal plant with four generating units could have a major overhaul for one unit in one of the four-year cycles. Each year, a unit is offline for a planned outage at about the same time in the spring. In the test period, all four units will be scheduled to have a planned outage, which will last for one fourth of the actual historical duration. If, in the test period, the planned outage of all four units were to be scheduled based on the historical timing of their corresponding outage time, all four units of the plant would be on planned outage at the same time. Such outages would not be consistent with the actual operation of the Company's resources, which demands reliability.

**Q. What process does the Company use to place the various units into the model in scheduling planned outage times?**

A. The Company uses a tree-modeling approach which systemically spreads planned outages for thermal units over defined periods of time, as shown in Exhibit RMP___(GND-2). Using history as a guide, the Company understands that spring and fall time frames are the cheapest periods of time to have plants offline. Based on the tree structure, the planned outages for most of the units are sequenced and scheduled in the spring. For normalized rate making purposes, planned outages are scheduled so that all units are on planned outage during the test year, and the timing of the outages are scheduled not to fall within certain periods during the year due to the obligations to serve both the retail load and wholesale contracts.

For example, the schedule takes into consideration the need to avoid planned outages in the winter and the summer.

With this requirement, it is necessary for several units to be on planned outage simultaneously. However, the number of major units on planned outage is not to exceed three on a control area basis. As a result, not all of the plants can be overhauled in the spring when the market prices are generally lower. In addition, the units are sequenced to approximate the effect of fully utilizing the same crew by location.

**Q. Do you assume the same fixed planned outage schedule in all normalized net power cost calculations?**

A. No. The schedule for each unit may change slightly depending on the length of the normalized planned outages that precede it. However, the structure of the planned outage tree will remain the same from one proceeding to another.

**Q. In the current proceeding, has the Company included a credit for the electricity that is generated during the startups of the gas-fired thermal units?**

A. No. In Docket No. 08-035-38, there was intervenor testimony regarding the value of the generation when gas-fired units are starting up. While it is correct that the units do generate power when starting up, the value of such generation is expected to be small.

**Q. Please explain.**

A. The ramping up of generation during the start up of gas-fired units is much like intra-hour wind increases described in the section below on wind integration charges. Extra reserves have to be held back to provide intra-hour regulate down services for the gas plant while it ramps up to minimum load. Reserves for regulate up services would also need to be held when the gas units cycle off from minimum load. If these are met by hydro resource, then the value of the energy during startup would be near zero. If the ramping was done by coal plants, the value would be based on coal fuel cost savings and would need to account for the cost of operating the coal plant at a higher heat rate than it otherwise would have operated. None of the additional cost of reserves is reflected in the GRID study. Moreover, in normal operations, it is assumed that the majority of the intra-hour ramping is met with hydro. As long as water is not lost to spill, the value is expected to be small and could be either positive or negative. As a result, the Company has assumed that there is no net value associated with energy produced when gas-fired units are starting up.

**Q. Has the Company modeled short-term firm transmission as it did in its rebuttal testimony in Docket No. 08-035-38?**

A. Yes. The Company has included the as, if and when available short-term firm transmission in the GRID model only when the nature of the transmission made it the functional equivalent of long-term transmission. In other words, if the Company relied upon certain short-term transmission in a manner that made it as predictable and foreseeable as long-term transmission, the Company included that transmission in the model. Otherwise, the Company excluded this transmission on the basis that its inclusion was inconsistent with normalized ratemaking.

**Q. Why did the Company include both the non-firm and short-term firm transmission?**

A. In the Order in Docket No. 07-035-93, the Company was directed to include the non-firm transmission in its net power cost calculations. However, as non-firm purchase and sales of the electricity transactions, the non-firm transmission transactions are not known and predictable nor do they support the same level of reliability as firm transmission. While the Company has included non-firm transmission in this case to comply with the Commission's order, the Company continues to have reservations about the appropriateness of including this transmission in its net power costs study.

**Enhancements to the GRID Model**

**Q. Please describe the enhancements of the hydro inputs that the Company made in the filing.**

A. There are two enhancements to the hydro inputs of the GRID model. The first enhancement is to take the optimized hourly shaped hydro generation directly from the VISTA model. The second enhancement is to explicitly model the reduced generation related to operating the hydro units at a lower generation level for reserve purposes using "motoring" and accounting for efficiency losses.

**Q. Please explain the reduction in hydro generation due to motoring for spinning reserves.**

A. In order to meet spinning reserve requirements, the Company must keep generating resources connected to the grid and responsive to automatic generation control. One option for providing spinning reserves is to "motor" a unit which means the unit is connected to the grid and spinning with electrical energy rather than with water. At the Swift plant, the normal amount of energy required to motor a unit is about two megawatts. Motoring the unit with two megawatts of energy provides spinning reserve for the full range of unit output. To spin the unit at minimum load with water would require a flow through the turbine of about 350 cubic feet per second, which is extremely inefficient and would consume the equivalent of about 10 megawatts. Even though motoring consumes energy, it is more efficient and cost-effective than spinning a unit with water.

**Q. What are the efficiency losses?**

A. To provide load following and system regulating requirements, generation from dispatchable hydro units at the Swift and Yale plants from time to time operate significantly below or above peak efficiency. However, the forecasted hydro generation data from the Vista model is optimized at peak efficiency. The cumulative effect of load following with hydro units is less efficient operations. In other words, less energy is generated with the same amount of water than would have been generated at peak efficiency.

**Q. How does the Company adjust for the lost generation?**

A. The lost generation from the Company's Lewis River projects is modeled as adjustments to load. The amount of the adjustment is based on 2008 historical information.

**Wind Integration Charges**

**Q. Has the Company updated its wind integration charges?**

A. Yes. There are two categories of wind integration charges: one for the

Company's wind resources located in the BPA's control area, and one for the wind resources located in Company's control area. For the former, the charge has been updated from $0.68 per kW-month to $2.72 per kW-month based on the most recent proposal from BPA in its current transmission rate case, which is approximately $9.07 per megawatt hour based on a 30 percent capacity factor for the wind resource. For the latter, the Company has updated the value of the integration charge to incorporate the latest information in the Company's 2008 Integrated Resource Plan ("IRP") Appendix F which is included as Exhibit RMP__(GND-3).

**Q. Which wind plants are assessed wind integration charges?**

A. All wind plants in the Company's control area, including non-owned wind plants, with the exception of Leaning Juniper and Goodnoe Hills are assessed the Company's wind integration charge. Leaning Juniper and Goodnoe Hills are in BPA's control area and are assessed the BPA wind integration charge.

**Q. Please explain the update to the Company's wind integration charges.**

A. As part of its 2008 IRP filed with the Commission on May 28, 2009, the Company has performed studies on the impact of integrating the generation from the wind projects into its system. Based on the same assumptions and methodology but using the data applicable to the test period, the Company calculated the costs incurred for wind integration as $6.91 per megawatt hour for the test period of 12-month ending June 2010.

**Q. How does the calculation of the wind integration costs differ from the prior study?**

A. There are two primary differences. First, the new study uses ten-minute data to determine the intra-hour (within the hour) costs while the old study used hourly data. Second, the new study identifies five separate cost elements. These include day-ahead and hour-ahead system balancing costs, as well as reserve costs related to forecast deviations, regulate up and regulate down. The first two costs are inter-hour (hour-to-hour) costs and the latter three are intra-hour (within hour) costs. Out of these five cost components, the Company's prior wind integration study included only forecast deviations.

**Q. What do you mean by regulate up and regulate down?**

A. These are the costs associated with holding resources in reserve to follow the intra-hour variability of wind plants. As generation from the wind plants increases during the hour, other plants must reduce generation (regulate down), and as generation from the wind plants decrease during the hour, other plants must increase generation (regulate up).

**Q. Why do wind plants incur these costs?**

A. The shape of a wind energy delivery pattern is different than the delivery patterns of other generation resources. Because wind is intermittent and variable, so is wind generation. Generation from wind resources is both non-dispatchable and uncertain. When a consistent schedule of energy is available, balancing activities are greatly reduced. Conversely, when energy is intermittent like wind generation, short-term (next hour or next day) forecasts have greater variability relative to longer-term wind energy expectations, and balancing activities must occur to accommodate the deviation between the wind forecasts and realized output.  These balancing activities and the associated costs occur on a day-ahead, hour-ahead, and within the hour timeframe.

**Inter-Hour (Hour to Hour) Wind Integration Costs**

**Q. How does the Company predict how much wind will be generated in an hour?**

A. In the first instance, the Company includes wind facilities in its operating resource balance based on an initial forecast. This is generally taken from the most recent modeled forecast for new facilities, and can be informed by actual operational data after the plant has been operating for several years. The Company makes two additional forecasts for each wind plant as the hour of delivery approaches. The first one is made near enough to the delivery time so the traders can balance the position in the day-ahead markets. The second updated forecast is done in time for the traders to balance the position in the hour-ahead market. Each forecast provides the system operators with the best information on how much each wind plant will generate and allows the traders to balance the system in a manner that will minimize the overall cost of integrating wind into the system.

**Q. Is there a cost to truing up the forecast in the day-ahead and hour-ahead markets?**

A. Yes. The rebalancing or closure of open positions generated as new load and wind forecast data becomes available requires the payment of transaction costs. For day-ahead trades, this is limited by the size and availability of standard 25 megawatt blocks for standard 16-hour or 8-hour (on-peak and off-peak) delivery patterns. The Company incurs transaction costs every time it trades a block of 25 megawatts. These transaction costs vary depending on the time of day and location and are currently estimated to be about $0.50 per megawatt hour over market for purchases to cover a shortfall in forecast, and $0.50 per megawatt hour under market for sales to cover a forecast excess during most transactional hours. Given the hourly difference between the long-term expected wind generation and the historical wind generation forecasts at the day-ahead horizon, the day-ahead costs included in the net power costs are $0.32 per megawatt hour, reflecting the fact that the $0.50 per megawatt hour is not incurred in every hour of the year for all of the wind plants.

Similar to the day-ahead variation, the rebalancing of energy to close open positions due to the change in forecasted persistence for wind energy from the day-ahead schedule to the hour-ahead schedule also adds transaction costs. Hour-ahead transactions are assumed to be in one megawatt increments, but transactions costs are up to twenty-five percent of the per-megawatt-hour energy costs. The precise percentage depends on then–current market conditions and the amount of energy traded. A cost of $1.76 per megawatt hour, which is the weighted average of the percentages and sizes of the transactions, is included in net power costs to reflect the rebalancing resulting from the difference between the day-ahead and hour-ahead forecasts. Combined with the day-ahead cost, this results in a total inter-hour cost of $2.08 per megawatt hour.

**Intra-Hour (Within the Hour) Wind Integration Costs**

**Q. What costs does the Company incur during the hour of delivery?**

A. The Company incurs costs associated with holding additional reserves to cover variances in the hour-ahead forecast compared to actual delivery within the hour, as well as holding additional reserves to accommodate the increases and decreases in generation from the wind plant during the hour. Intra-hour wind variability requires the dispatch of existing units to balance the system as there is no intra-hour market. Costs of reserves are incurred even if there are no variances from the forecast..

**Q. How did the Company determine the amount of additional reserves required for intra-hour forecast variance?**

A. The Company computed the deviation of the actual hourly average energy from the hour-ahead forecast given the historical hour-ahead wind generation forecast and actual hourly energy values. This was used to produce statistical hourly distributions of the forecast versus actual energy. The Company correlated these results and two additional sources of intra-hour uncertainty: "regulate down" and "regulate up".

**Q. How were the amounts of additional reserves needed for "regulate up" and "regulate down" determined?**

A. Regulate up is the difference between the minimum wind energy within the hour (using ten-minute interval wind generation data) and the energy at the beginning of the hour. When wind energy moves down within an hour, other resources on the system are required to increase output to compensate for this intra-hour energy deviation. Regulate down is the difference between the maximum wind energy within the hour (using ten-minute interval wind generation data) and the energy at the beginning of the hour. When wind energy moves up within an hour, other generation resources are required to reduce their output to compensate for this intra-hour energy deviation. The analysis of ten-minute interval wind generation data yields a statistical distribution of the difference between the wind energy at the beginning of the hour and the ten-minute period of minimum (in the case of regulate up) or maximum (in the case of regulate down) energy within the hour. Taking two standard deviations of the resultant statistical distribution allows reserves associated with this factor to be estimated at a confidence interval consistent with PacifiCorp's North American Electric Reliability Corporation's Control Performance Standard II (CPS II)[1] standard.

**Q. How were the costs of these three intra-hour components determined?**

A. A reserve resource stack model was developed that is used to estimate both in-the-money and out-of-the-money reserve costs. In-the-money reserve costs are measured by calculating market prices less the cost of thermal dispatch (fuel, variable O&M, and $SO_2$ emission costs). Out-of-the-money reserve costs are estimated by calculating the above market operating costs of a unit dispatched at minimum capacity divided by the total amount of reserve capability available once at minimum load. The reserve requirement is then filled by the lowest cost in-the-money or out-of-the-money thermal resource considering the resource reserve capacities and unit ramp rates. The Company used market prices at Mona, Mid-Columbia, and Four Corners from the March 31, 2009 Official Forward

[1] The CPS II standard refers to the compliance bounds for the 10-minute average of the Area Control Error.

Price Curve (the same curve used to calculate net power costs for this case) for purposes of estimating the cost of holding reserves on the Company's system.

**Q. What is the cost of these three intra-hour components?**

A. The total intra-hour cost included in the net power cost study is $4.83 per megawatt hour. Combined with the $2.08 per megawatt hour inter-hour rebalancing costs, the total wind integration cost is $6.91 per megawatt hour.

**Q. Does this conclude your testimony?**

A. Yes.