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

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. Please 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") for the 12-month period ending May 31, 2013. Specifically, my testimony:

- Describes the primary drivers behind the increase in NPC as well as factors that mitigate the increase;
- Describes changes the Company has made to the NPC study since the

Company's 2011 general rate case ("2011 GRC"), Docket No. UT 10-035-124;

- Updates the hedging and wind integration costs included in the Company's NPC; and
- Proposes a process to update NPC during this and future general rate case proceedings to improve the accuracy of the base NPC rate while accommodating the needs of other parties to review and validate the NPC updates.

Summary of Net Power Costs in the Current Filing

Q. What are the proposed system-wide NPC for the 12-month period ending May 2013?

A. The proposed NPC for the 12-months ending May 31, 2013, are $1.500 billion on a total Company basis, and $645 million on a Utah allocated basis. The proposed total Company NPC are approximately $25 million higher than the $1.475 billion currently included in rates, and $15.6 million on a Utah allocated basis.

Q. Please generally describe the drivers of the Company's NPC in this filing.

A. Table 1 below illustrates the change in total Company NPC by category from the NPC baseline in the 2011 GRC Stipulation, which included a $33 million settlement adjustment. This adjustment is reflected in Table 1, and as will be discussed, the Company has incorporated a number of adjustments in the current filing that were proposed by parties in the 2011 GRC.

Table 1

Net Power Cost Reconciliation ($millions)

2011 General Rate Case	**1,475**
Wholesale Sales	46
Purchased Power	(13)
Coal Generation	34
Gas Generation	(71)
Wheeling Hydro and Other	(5)
Total Increase/(Decrease)	**(9)**
Settlement Adjustment	**33**
2012 General Rate Case	**1,500**

As shown in Table 1, the increase in NPC is driven largely by the decrease in wholesale sales revenue of $46 million and an increase in coal costs of $34 million. These increases in costs are offset by a decrease in purchased power expense of $13 million, wheeling expense of $5 million, and a decrease in the cost of gas generation of $71 million. On a total Company basis the proposed NPC represents an increase of 1.7 percent from the amounts currently included in rates. The major factors driving the level of NPC proposed in this proceeding are an overall reduction in both electricity and natural gas prices and a reduction in the retail load forecast of 2,472 gigawatt-hours ("GWh") as compared to the 2011 GRC load forecast.[1]

Q. On an energy basis, how has the operation of the Company's system changed since the 2011 GRC?

A. With regard to energy, the primary change to the Company's system is the

[1] The Company continues to forecast increases in loads over time, but at a lower rate of growth than was expected in the forecast used in the 2011 general rate case.

decrease in the retail load forecast of 2,472 GWh as noted above. Consistent with the lower forecast of retail load, wholesale sales increased by 1,303 GWh and purchased power volumes decreased by 1,249 GWh. With regard to the Company's thermal generation, gas generation increased by 1,257 GWh and coal generation decreased by 1,034 GWh. The changes in the dispatch of the Company's thermal generation fleet can be best explained by changes in electricity and natural gas prices relative to the 2011 GRC. With the continued decline in average market prices the decision to generate power in order to sell into the wholesale market is contingent on electricity prices and natural gas prices relative to the variable operating costs of the individual thermal units. This relationship of electricity prices, natural gas prices, and the operating costs of the thermal generation fleet will be discussed in more detail later in my testimony.

Discussion of Major Cost Drivers in NPC

Q. Please discuss the reduction in wholesale sales revenue in NPC in the test year.

A. As shown in Table 1, on a total Company basis, wholesale sales revenues have declined by $46 million, or 8 percent, since the 2011 GRC, even though the total volume of sales has increased by approximately ten percent (1,303 GWh).

Q. Please explain why wholesale sales revenues declined, despite the increase in sales volumes related to lower retail loads.

A. The decline in wholesale sales revenues is driven by the reduction in wholesale sales prices. The increase in volume was not great enough to overcome the reduction in price. Had prices remained at the same level as the 2011 GRC, this additional sales volume, net of fuel costs, would have yielded a $9 million reduction to NPC.

Q. Has the Company also seen a decrease in purchased power expense and volume?

A. Yes. With the reduction in load and lower market prices, purchased power volumes declined by 1,249 GWh which resulted in an overall reduction in purchased power expense of $13 million. The reduction in purchased power volumes was also driven by an increase in the amount of generation from the Company's natural gas plants, which are now more economic because gas prices have fallen more than power prices, as described in further detail below.

Q. Please discuss the changes in wholesale electricity prices and the changes in natural gas prices since the 2011 GRC.

A. Wholesale electricity prices have declined by approximately 10 percent and natural gas prices have declined by approximately 24 percent since the 2011 GRC. In order to understand the impact these changes have on NPC it is important to look at it on a monthly basis, as well as by high load hours ("HLH") and low load hours ("LLH"). Table 2 shows the change in wholesale electricity prices (average market price at the Mid-Columbia ("Mid-C") and Palo Verde trading hubs) by month and by HLH and LLH. Table 3 shows the change in gas prices by month at the Opal trading hub, which is a source of gas for the gas plants located in Utah.

Table 2

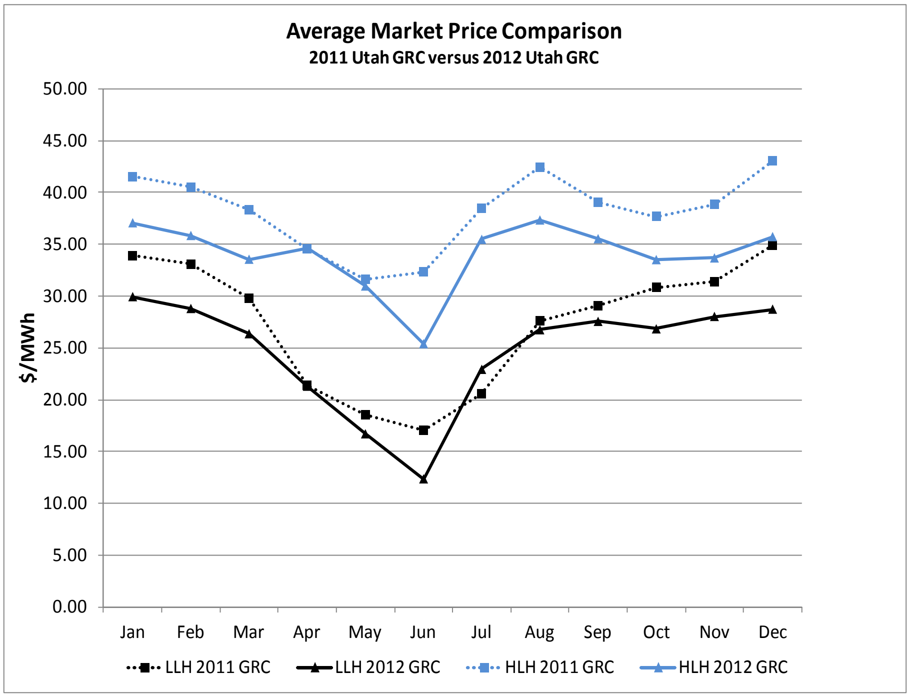
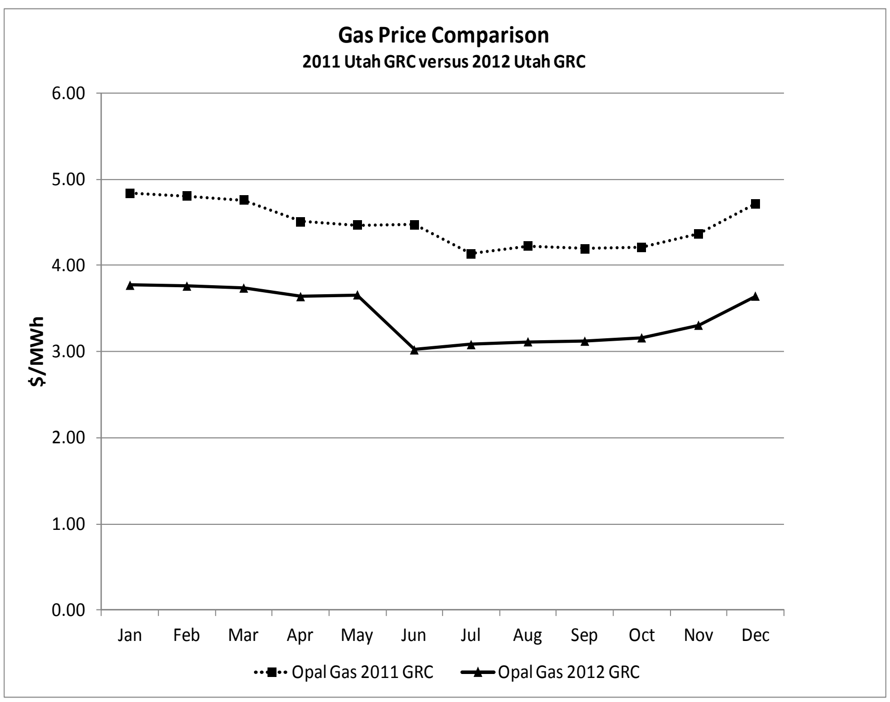


Table 3



Q. How did the change in natural gas prices impact the operation of the Company's natural gas resources?

A. As shown in Tables 2 and 3, both wholesale electricity and natural gas prices decreased since the 2011 GRC. However, as noted above, the reduction in natural gas prices was greater than the reduction in electricity prices, meaning that the Company's gas resources became more economic to operate relative to purchased power prices, especially in LLH. Table 4 below shows the change in the operating costs of the Company's natural gas resources relative to average LLH market prices as compared to the 2011 GRC.

Table 4

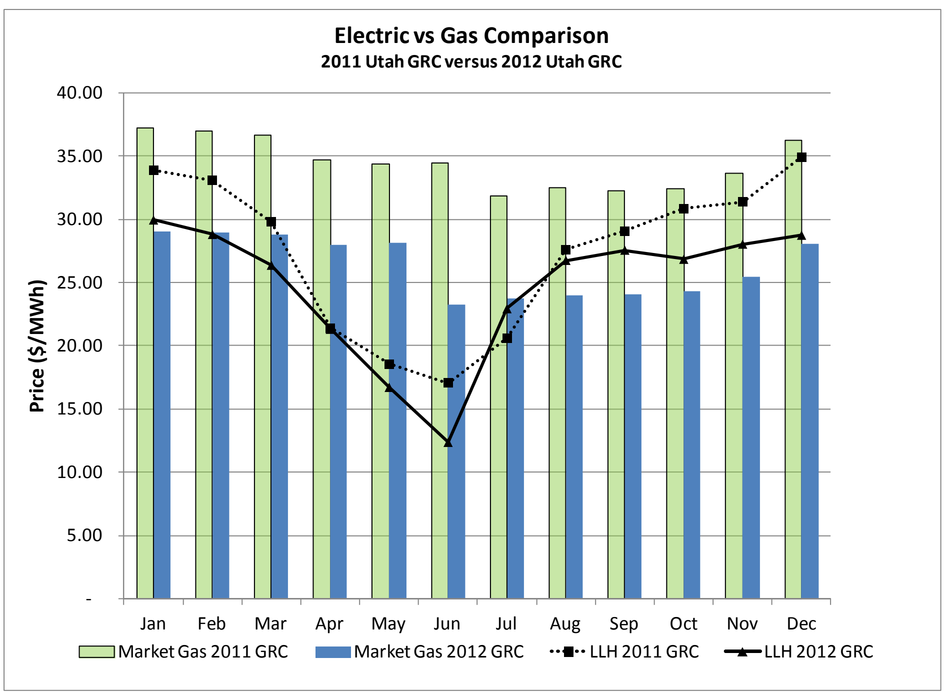


Table 4 shows that relative to market prices, natural gas generation is now more economic to operate than buying power in the wholesale markets during LLH for six months in the test period. Comparatively, in the 2011 GRC, gas generation was uneconomic as compared to LLH market prices in all months of the prior test period. Intuitively this might imply that LLH market prices have increased, however, that is not the case. As can be seen in Table 4, there was a more significant reduction in natural gas prices relative to the decrease in electricity prices, making the Company's gas generation more economic during LLH. Indeed, the majority of the increase in gas generation occurred in LLH.

Q. Please explain the increase in coal expenses in the current proceeding.

A. Approximately $34 million of the system NPC increase in the current proceeding is attributable to coal costs. Price increases are reflected in both the costs of third-party coal supply and transportation agreements, and cost increases at the Company's captive mines. Coal generation has decreased because forecasted retail load is lower and because market prices are lower in the test period versus the 2011 GRC, resulting in less economic dispatch of the coal units. Details on coal price changes are provided in the direct testimony of Company witness Ms. Cindy A. Crane.

Q. Please further explain the reduction in coal generation in the current proceeding.

A. Coal generation fell by approximately 1,034 GWh from 44,082 GWh in the 2011 general rate case to 43,048 GWh in the current test period. Unlike gas generation that increased as a result of changing market prices, coal generation declined as falling market prices reduced generation from coal. In certain hours, especially during periods of spring runoff and excess hydro generation, market purchases are less expensive than the fuel cost of coal units, resulting in a reduction in the dispatch of coal units in those hours. When comparing coal generation during

HLH total generation is higher in the current proceeding than the 2011 GRC.

Q. Are there any other factors that contribute to the reduction in coal generation?

A. Yes. Reduced loads resulted in more times when the Company experienced transmission constraints in Wyoming that limited its export capability of available coal generation.

Q. What caused the reduction in retail loads?

A. The 2,472 GWh reduction in the retail load forecast in this case reflects the fact that the actual retail sales in 2011 came in below the levels forecast in the 2011 GRC. In addition, a number of industrial customers with on-site generation are expected to serve a portion of their requirements with their own generation and several data centers have indicated that their expansion plans will not occur as soon as they previously indicated. While the Company continues to forecast load growth, it is expected to be slower than the October 2010 forecast that was used in the 2011 GRC. For further details on the load forecast, please refer to the testimony of Company witness Dr. Peter C. Eelkema.

Q. Why has wheeling expense decreased?

A. Wheeling expense has decreased primarily as a result of the expiration of the Centralia point-to-point wheeling contract on June 30, 2012.

Changes to the NPC Study since the 2010 GRC

Q. What changes has the Company made to the NPC study since the 2011 GRC?

A. In response to issues raised by parties in the Company's 2011 GRC, the Company refined the following inputs to Generation and Regulation Initiative Decision model ("GRID"):

- Lewis River – The Company now inputs normalized generation into the GRID model on a weekly basis to better reflect the Company's operation of its hydro facilities for generating and providing reserves. This addresses the Utah Office of Consumer Services ("OCS") proposed adjustment 8 from the 2011 GRC.
- Bear River – The normalized capacity and generation now includes the impact of flood control years and reflects the Company's more recent operation of the Cutler and Oneida plants and their ability to provide an increased level of reserves through motoring of the units. This addresses OCS proposed adjustment 7 and the Utah Industrial Energy Consumers ("UIEC") proposed adjustment 14 from the 2011 GRC.
- California Independent System Operator ("Cal ISO") – Transactions with the Cal ISO are now explicitly modeled in the GRID based on historical levels. This addresses the Division of Public Utilities ("DPU") proposed adjustment 7, OCS proposed adjustment 10.1, and UIEC proposed adjustment 1 from the 2011 GRC.
- DC Intertie – The Company's rights to use the DC Intertie have now been added to the GRID topology. This allows GRID to purchase power at the Nevada Oregon Border ("NOB") market hub to serve load. This addresses OCS proposed adjustment 10.2 and UIEC proposed adjustment 8 from the 2011 GRC.

- Gadsby Must-Run – The Gadsby peaking units 4, 5 and 6 are no longer modeled as must-run units overnight. This addresses DPU proposed adjustment 2, OCS proposed adjustment 2.1, and UIEC proposed adjustment 3 from the 2011 GRC.
- Non-Owned Wind Ancillary Service Revenues – Company witness Mr. Steven R. McDougal proposes to extend the deferral of Schedule 3A ancillary service revenues from non-owned wind in the Energy Balancing Account ("EBA") without the application of the 30 percent sharing mechanism until the end of the test period May 31, 2013. This addresses DPU proposed adjustment 5 and part of OCS proposed adjustment 1 in the 2011 GRC.
- Morgan Stanley Call Options – These contracts have expired and have been removed from GRID. This addresses DPU proposed adjustment 8 and UIEC proposed adjustment 4 from the 2011 GRC.
- Centralia Point-to-Point Wheeling – This contract expires on June 30, 2012, and has been removed beyond that time. This addresses OCS proposed adjustment 10.3 and UIEC proposed adjustment 9 from the 2011 GRC.
- Hydro Outage Rates – The Company has adopted UIEC's recommendation from the 2011 GRC, relating to the base period used to calculate hydro outages. This addresses UIEC proposed adjustment 10 from the 2011 GRC.
- Bridger Coal Adjustment – The Company has systematically removed all fines and citations from coal costs. This addresses UIEC proposed adjustment 12 from the 2011 GRC.

- BPA Transmission Rate Increase – The rates for the Bonneville Power Authority have been set and are no longer an estimate for the test period in this case. This addresses OCS proposed adjustment 12.1 from the 2011 GRC.

Hedging

Q. Does the Company continue to include hedging costs from financial transactions in NPC?

A. Yes.

Q. Has the Company entered into any financial hedging transactions since the Company entered into a settlement agreement with all parties in the 2011 GRC on July 28, 2011?

A. Yes. The test period includes six electricity swap transactions that were entered into subsequent to July 28, 2011. The total impact of these electricity swaps on NPC is a net gain of $4,992. The test period does not include any gas swap transactions entered into subsequent to July 28, 2011.

Wind Integration Costs

Q. What wind integration costs are included in NPC?

A. The costs of integrating wind generation in the Company's balancing authority areas included in NPC are approximately $3.44/MWh.

Q. Does the Company continue to base its wind integration costs on the results of the 2010 Wind Integration Study ("Wind Study") filed with this Commission in both the 2011 GRC and the 2011 Integrated Resource Plan dockets?

A. Yes. The Company continues to believe that the level of reserves required to integrate wind generation net of system load, as identified in the Wind Study, is appropriate.

Q. Has the Company made any changes to the reserve requirements since the 2011 GRC?

A. Yes. The reserve requirement from the Wind Study has been increased to integrate the additional wind capacity in the test period. The Wind Study calculated that an average of 533 MW of reserves were necessary to integrate 2,046 MW of wind capacity. This level of reserves was included in the prior case. The test period for this proceeding includes an average of 2,280 MW of wind capacity, 234 MW more than in the Wind Study. To integrate this additional capacity, the Company increased the reserve requirement by 25 MW to 558 MW, based on the relationship between the reserves required at the two highest penetration levels in the wind study.

Q. Has the Company included the costs associated with integrating the non-owned wind generation in the Company's balancing authority areas?

A. Yes. As explained in the 2011 GRC, the Company is required by federal law to provide wind integration services to its wholesale customers on a non-discriminatory basis. Therefore, the Company continues to believe it is appropriate to reflect these costs in rates as prudent and necessary costs associated with operating its system.

Q. Has the Company filed its transmission rate case with FERC, and included charges for ancillary services for non-owned wind facilities?

A. Yes. The Company filed its transmission rate case on May 26, 2011, under docket number ER11-3643. In that case, the Company proposed a new Schedule 3A that will apply to all transmission customers delivering energy from generators in PacifiCorp's balancing authority areas to other balancing authority areas. The transmission rate case is ongoing with FERC.

Q. Will the Company include these incremental revenues resulting from the FERC transmission rate case in Utah rates once they are known and measurable?

A. Yes. As more fully explained in the direct testimony of Company witness Mr. McDougal, since the exact amount of any increase are unknown at this time, the Company proposes to defer any ancillary service revenues resulting from the FERC transmission rate case through the end of the test period May 31, 2013. This deferral will occur through the EBA without the application of the 30 percent sharing mechanism. Utah's allocated share of these deferred revenues that are incremental to revenues included in the Company's filing may then be passed through to Utah customers as directed by the Commission.

Improving NPC Accuracy

Q. Does the Company propose to update NPC during the course of this proceeding and in general rate cases in the future in order to improve the accuracy of the NPC projections?

A. Yes. The Commission authorized the Company to establish an EBA in which the base NPC will be set in general rate cases. In order to achieve the most accurate forecast of base NPC, and thus minimize the deferred NPC, the Company proposes to update the following limited categories of NPC:

- The official forward price curve for electricity and natural gas;
- Coal costs;
- Wholesale sales and purchase contracts for electricity and natural gas, for both physical and financial products;
- Transmission contracts to wheel generation to load centers; and
- Transportation contracts to deliver natural gas to generation facilities.

Q. Did the Company propose to update NPC in the 2011 general rate case?

A. Yes. In its rebuttal filing, the Company proposed to make several updates to NPC. No party objected to the inclusion of updates and the updated NPC was the basis for the NPC adopted in the settlement stipulation in that case. However, the Commission order was silent on whether updates would be allowed in the future.

Q. What is the Company proposing in this case?

A. The Company is requesting that the Commission establish a fixed schedule of when NPC updates will occur over the course of a rate case proceeding and what particular NPC items will be updated. This will ensure that the update process is applied consistently and that no party will selectively accept or reject updates only on the basis that they increase or decrease NPC.

Q. When does the Company propose to make these updates during this proceeding and future general rate case proceedings?

A. The Company proposes to update NPC for the limited categories prior to parties' filing their direct testimony. In this proceeding, the Company proposes to file the update one month prior to the date that other parties will file direct testimony. In addition, prior to the update filing, the Company will periodically provide new information in those categories that will be reflected in the update filing, either on a monthly basis or when a significant amount of information has been accumulated. The Company believes that this will allow adequate time for parties to review the information prior to filing their direct testimony.

Q. Why is it reasonable to update NPC during the course of a general rate case proceeding?

A. The Company's load and resource balance for any given period change with time, as do market prices and contracts. As a result, the operation of the Company's system continues to change during the course of the NPC proceeding. The Company's proposal to update NPC will ensure that the NPC forecast for the rate effective period is as accurate as possible.

Q. Will such updates unreasonably impact other parties' abilities to review the Company's NPC?

A. No. The Company believes the review time is reasonable given the limited scope of the update and the provision of new information in a timely fashion. These updates are transparent, apply equally whether they increase or decrease NPC, can be easily verified and are straightforward to model in GRID. In addition, the Company will provide work papers to support these updates.

Q. Do other commissions allow the Company to update its NPC inputs, including the forward price curve after the initial filing?

A. Yes. This has become the regular practice in Oregon and Washington with the goal of improving the accuracy of the NPC in rates. For example, the Oregon Commission authorizes the Company to update its forward price curve and new information on contracts for electricity and natural gas after it has entered its final order, but prior to the time rates go into effect. The Company made this same proposal in its current Wyoming rate case that was filed on December 09, 2011. The Wyoming Public Service Commission has included the NPC update in the procedural schedule for that case. The Company made this proposal in Wyoming for the same reasons it is making it in this case; to improve the accuracy of base NPC in order to minimize the EBA true-ups.

Determination of NPC and Model Inputs and Outputs

Q. Please explain NPC.

A. NPC 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 NPC.

A. NPC are calculated for a future test period based on projected data using GRID. 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 has used the GRID model to determine NPC in its Utah filings for several years.

Q. Is the Company using the same version of the GRID model as used in its 2011 general rate case?

A. Yes.

Q. What inputs were updated for this filing?

A. All inputs have been updated since the 2011 general rate case, including system load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, market prices for electricity and natural gas, fuel expenses, and the characteristics and availability of the Company's generation facilities. As noted previously, many issues raised by intervenors in the 2011 general rate case have also been addressed in this filing.

Q. Has the Company changed its GRID model topology?

A. Yes. There are two main changes to the GRID model topology. The first change better reflects the wheeling contracts with Idaho Power Company and the impact of the Populus to Terminal line. The second change better reflects the operational constraints of the Company's wheeling contracts with the BPA after the expiration of the BPA Peaking contract.

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 RMP___(GND-1). The GRID model also produces more detailed reports in hourly, daily, monthly and annual formats by heavy-load hours and light-load hours.

Q. Does this conclude your direct testimony?

A. Yes.