BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power For Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.	))))))	DOCKET NO. 10-035-124 DPU EXHIBIT 12.0 D-RR

PRE-FILED DIRECT TESTIMONY

GEORGE W. EVANS

ON BEHALF OF THE

UTAH DIVISION OF PUBLIC UTILITIES

May 26, 2011

PUBLIC

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INTRODUCTION

Q. Please state your name, business address, employer, and current position or title for the record.

A. My name is George W. Evans, and my business address is 358 Cross Creek Trail, Robbinsville, North Carolina 28771. I am a Vice President with Slater Consulting.

Q. For whom are you providing testimony in this case?

A. I am providing testimony on behalf of the Utah Division of Public Utilities (DPU or Division).

Q. Please describe your education and work experience.

A. I received a Bachelor of Science in Applied Mathematics from the Georgia Institute of Technology in 1974. In 1976, I received a Master of Science in Applied Mathematics, also from the Georgia Institute of Technology. My area of concentration was probability and statistics. In 1980 I joined Energy Management Associates, Inc. (EMA), the company responsible for the development of the premier electric utility modeling tools, PROMOD®, PROSCREEN®, PROVIEW® and MAINPLAN®. While at EMA, I worked with some fifty (50) major electric utilities in the United States and Canada in the application of these modeling tools for generation expansion planning, the development of net power costs, fuel budgeting, the analysis of power purchases and the development of optimal maintenance schedules for generating units.

In 1989 I left EMA to join GDS Associates, Inc., a consulting firm located in Marietta, Georgia. At GDS I was a principal and the Manager of System Modeling. In this position I was primarily responsible for performing analyses and presenting expert testimony concerning integrated resource planning, the forecasting of system production costs, developing estimates of the likelihood of service interruptions, developing estimates of replacement power costs and related activities.

In August of 1997 I left GDS to join Slater Consulting as a Vice President. A copy of my résumé is included in DPU Exhibit 12.1.

Q. Where have you testified before?

A. I have provided expert testimony on 38 previous occasions, before the public utility commissions in Pennsylvania, Georgia, Michigan, Arkansas, South Dakota, Colorado, Illinois, Mississippi, Alabama, Delaware, South Carolina and Oklahoma; and also before the FERC (Federal Energy Regulatory Commission), and in state court and federal court. A complete list of the proceedings that I have testified in is in DPU Exhibit 12.1.

Q. Have you appeared before the Public Service Commission of Utah (Commission) in the past?

A. Yes, I have. I presented direct, supplemental and rebuttal testimony on behalf of the DPU in Docket No. 09-035-23, the previous general rate case for Rocky Mountain Power Company. In addition, I served as the DPU's consultant on net power cost issues in the Company's two 2010 major plant addition cases.

PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to identify and quantify certain recommended adjustments to the Company's Net Power Costs (NPC) as proposed in the current Utah rate case. In this rate case PacifiCorp, which does business in Utah as Rocky Mountain Power (the Company), proposes a rate increase of $527.1 million over the forecasted test period July 1, 2011 through June 30, 2012. My recommended adjustments total a reduction to NPC of approximately $144 million, with a reduction of approximately $62 million allocated to Utah.

Q. What is the amount that the Company has filed as a Total Company NPC for the test year?

A. As identified in the direct testimony of Company witness Mr. Gregory N. Duvall (page 2, lines 34-36), the Company's normalized NPC for the test year are approximately $1,521 million, with approximately $649 million of these costs allocated to Utah.

Q. What recommendations are you making in this filing?

A. I am recommending eleven adjustments to the Company's filed NPC, and also including one additional adjustment (the twelfth adjustment in Table 1) that will be supported by other DPU witnesses.

Table 1

		System	Utah
Filed Net Power Costs		$1,521.0	$649.1
Proposed Adjustments:			
Utah QF Contracts:			
1	Extend Utah QF Contracts at Current Rates	$0.3	$0.1
Wind Integration Costs:			
2	Correct Gadsby CT Usage	-$3.8	-$1.6
3	Remove Double-Count of Wind Contingency Reserves	-$2.0	-$0.9
4	Correct Spinning Reserve Increase	-$13.6	-$5.8
5	Credit for Wind Integration Costs of Non-Owned Wind Producers	-$4.1	-$1.7
Contracts and Market Sales and Purchases:			
6	Market Cap Adjustments	-$5.3	-$2.2
7	California ISO Fees	-$4.3	-$1.8
8	Morgan Stanley Call Options	-$2.1	-$0.9
9	Arbitrage & Trading Margins	-$3.0	-$1.3
Fossil Generation Issues:			
10	Heat Rate Deration Issue	-$4.1	-$1.7
11	Chehalis Reserve Contribution	-$3.4	-$1.4
Gas and Electric Swaps			
12	Gas and Electric Swaps	-$99.0	-$42.3
Total Adjustment		-$144.4	-$61.6
Adjusted Net Power Costs		$1,376.6	$587.5

Q. Will you describe each of these recommended adjustments?

A. I will describe the first eleven adjustments to NPC in the following sections of my testimony.

UTAH QF CONTRACTS

Q. What is the issue concerning the Utah QF contracts?

A. The Company's GRID model used for this filing does not include costs for the Kennecott, Tesoro, or U.S. Magnesium Corp. (U.S. Magnesium) qualifying facilities (QFs) after December 2011. The Power Purchase Agreements (PPAs) for each of these QFs expire on December 31, 2011. However, it is highly likely that these agreements will be renewed. These QFs should be included in the Company's NPC estimate for the remaining six months of the test year. Including these QFs increases the Company's Utah allocated NPC figure by about $116,813.

Q. Why do you believe that these contracts are likely to be renewed?

A. Contracts with Kennecott, Tesoro and U.S. Magnesium have been in place and periodically renegotiated or renewed for a number of years. At this time, there is no reason to believe contract renewals will not continue to occur in the future.

Q. If there are modifications to these contracts, do you anticipate that they will be significant?

A. No, I do not.

Q. What have you assumed concerning the contract terms after December 2011?

A. I have extended the QFs through June 2012 at the same contract terms that existed in December 2011. That is, I've assumed no contract changes.

WIND INTEGRATION COSTS

Q. Please describe the wind integration costs that the Company has included in NPC.

A. The Company has included [redacted] million in wind integration costs. This amount is equivalent to [redacted] per megawatt-hour of Company-owned wind generation. However, the Company does not include the wind integration charge as a dollar per megawatt-hour charge (as was done in the previous rate case), but instead makes several modeling changes within GRID to accomplish the desired result.

Q. What is the basis for the Company's modeling changes?

A. The Company performed a new wind integration study (Wind Study) as a part of its 2011 Integrated Resource Plan. This Wind Study is the basis for the modeling changes made in GRID to address wind integration costs.

Q. What modeling changes were included within GRID?

A. The Company increased the required level of operating reserves within GRID and forced the Currant Creek combined cycle unit and the Gadsby combustion turbines (Gadsby units 4, 5 and 6) to operate whenever available regardless of economics. In addition to these modeling changes, the Company also charged $0.71 per megawatt-hour for system balancing costs for Company-owned wind generation and two wind facilities that are located in the Bonneville Power Authority (BPA) balancing area – Leaning Juniper and Goodnoe Hills. The system balancing charges account for [redacted] million of the total wind integration charges. The modeling changes in GRID account for the remaining [redacted] million.

Q. What issues do you have with the Company's Wind Study?

A. The Wind Study has two basic flaws. The study never considers actual operations, that is, how the PacifiCorp generating system is actually responding to additional wind generation, and the study makes a basic assumption that is clearly incorrect – the Wind Study assumes that reserves must be increased in all hours in response to wind generation.

Q. Please describe the study's failure to consider actual operations.

A. The Wind Study is a theoretical analysis that concludes that additional reserves must be carried and certain gas-fired generating units must operate in all available hours, without ever considering the actual operations of the Company's generating system.

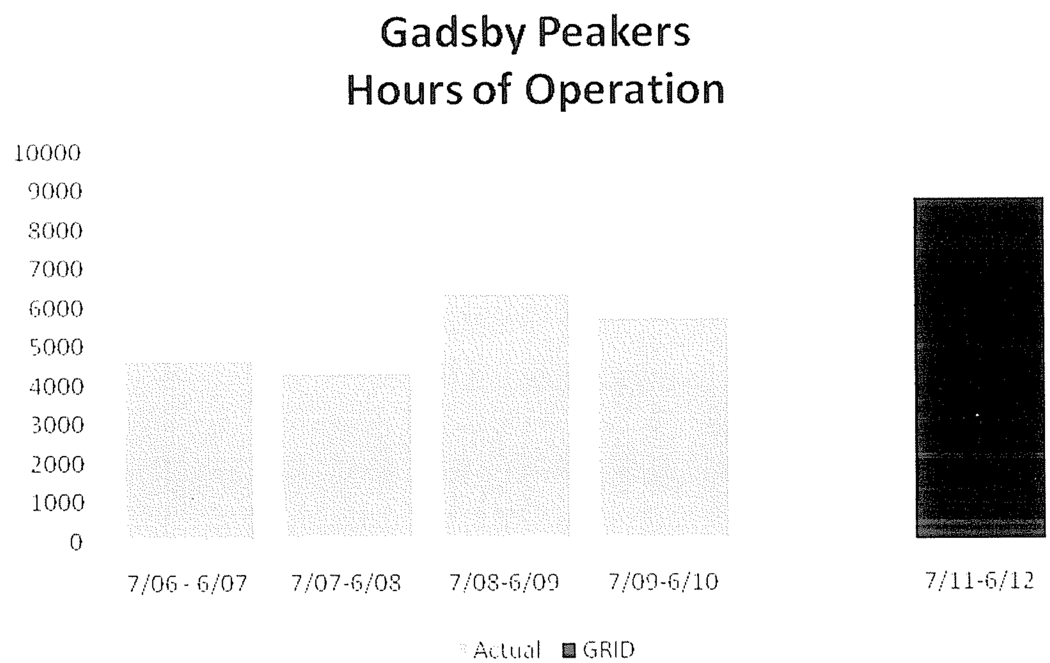
Q. Will recent actual Company operations reflect the Company's response to the intermittent nature of wind generation?

A. Yes. At the beginning of 2010, the Company had in operation [redacted] megawatts of wind capacity. Two additional wind generators began operations in October of

2010, bringing the total operating wind capacity to [redacted] megawatts. Thus recent actual Company operations should be representative of the operating changes necessary to integrate wind generation into the system. In fact, changes in system operations over recent years should show the move to the Company's assumed operating changes in the GRID runs.

Q. Do the GRID modeling changes used by the Company for wind integration reflect recent actual operations?

A. No, they do not. The Company assumes in GRID, based on the Wind Study, that the Gadsby peakers (Gadsby units 4, 5 and 6) will need to operate round-the-clock in response to the wind generation on the system. Thus in GRID, the Gadsby peakers operate in every hour of the test year, or 8,784 hours. The following graph shows that, in reality, the Gadsby peakers have never operated more than 6,261 hours in a recent July-June twelve month period, and in the most recent period available, only operated a total of 5,767 hours, or 65% of the hours assumed in GRID. This is a clear indication that the methodology utilized in GRID greatly exaggerates the costs of wind integration.

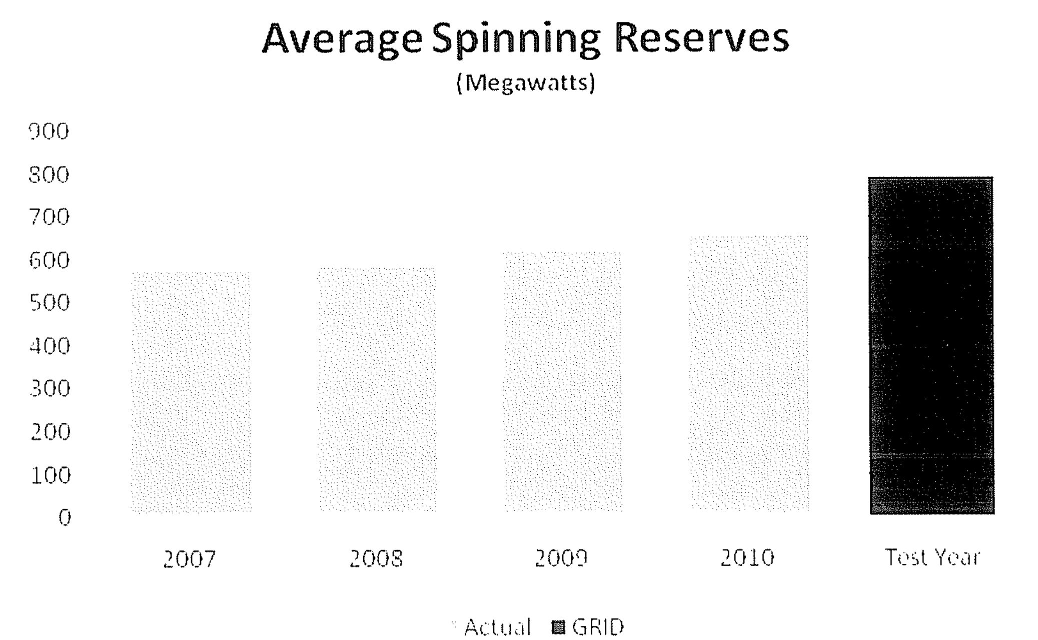


Q. Are there other problems with the Company's GRID changes for wind integration costs?

A. Yes. The Company also increased the hourly spinning reserve requirement in GRID, based again on the Wind Study.

Q. Do actual operations support this increase in spinning reserves?

A. No, they do not. The following chart compares the actual average hourly spinning reserves carried by the Company to the average hourly spinning reserves carried by GRID in the development of the Company's NPC. Given that nearly all the anticipated wind generation in the test year had been installed and operating in 2010, the increase in the GRID spinning reserves is unjustified.



Q. Are there other indications that the Wind Study exaggerates the need for additional spinning reserves?

A. Yes. In response to DPU Data request 10.34, the Company indicated that additional reserves would need to be carried in all hours for wind integration. In other words, the Company never considered whether existing reserves in some hours would be sufficient to cover the needs of wind integration. The Wind Study assumed that all hours would require additional reserves.

Q. Are there hours in which additional reserves would not be needed?

A. Yes. In many early morning hours, when customer requirements are low, but many generating units cannot be removed from service, there are generally excess reserves, which could be used for wind integration. The Company has made the blanket assumption that such hours do not exist. This will cause the Wind Study to exaggerate the level of reserves required for wind integration.

Q. Are there other problems with the Wind Study?

A. Yes. Several parties have raised issues with the Company's study. A major problem with the study is its use of estimated wind data rather than actual recorded wind data. Hopefully the Company will correct this issue in future studies.

Q. What adjustments to NPC do you recommend concerning wind integration costs?

A. Adjustments 2 through 5 in Table 1 concern wind integration. Adjustment 2 is the result of modifying the operation of the Gadsby peakers so that the units are forced to run in high load hours only, rather than in all hours, as in the Company's GRID run. This adjustment better reflects the actual operation of the Gadsby peakers.

Q. What is Adjustment 3 in Table 1?

A. Adjustment 3 removes the 5% wind contingency reserve that the Company has included in GRID in this case and in previous rate cases. The 5% wind contingency means that GRID will carry operating reserves equal to 5% of installed wind capacity to cover the potential complete loss of 5% of all installed wind facilities. However, based on the Wind Study, the Company has in this rate case increased the GRID spinning reserve requirement to cover the complete intermittent nature of wind generation. In other words, the increase in the GRID spinning reserve requirement covers all the potential losses of wind generation, and the 5% wind contingency is redundant. Leaving the 5% wind contingency in place, along with the increase in spinning reserves, would result in a double-count of reserves to cover the loss of wind generation.

Q. What is Adjustment 4 in Table 1?

A. Adjustment 4 reduces the spinning reserve requirement to reflect the actual spinning reserves carried by the Company's system, as discussed above.

Q. What is Adjustment 5 in Table 1?

A. Adjustment 5 reflects a credit for the two wind producers (Stateline and Long Hollow) that are based in the Company's balancing areas, but do not provide any wind generation to the Company's customers. The Company provides wind integration services for these two wind facilities, using System resources, but to date, has been unable to collect wind integration charges from the wind facilities. In other words, ratepayers are charged (through NPC) the cost to integrate the generation from these two wind facilities, but the ratepayers receive no benefit from the generation. Adjustment 5 would keep ratepayers whole.

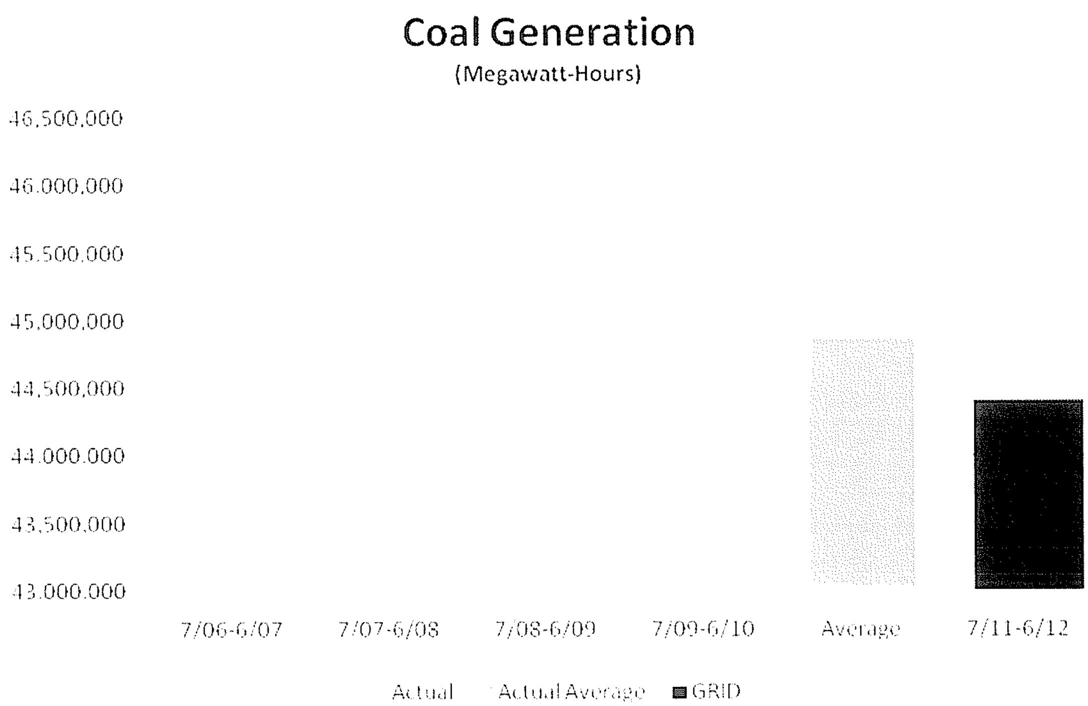
MARKET CAPS

Q. How has the Company modified the market capacity limits in this proceeding?

A. In the previous rate case, the Company only used capacity limits on the major wholesale markets in graveyard hours. In this case, the Company has included capacity limits on all the major markets in all hours.

Q. Are these limits appropriate?

A. No. These limits have restricted the generation of the Company's coal plants to a level lower than the average generation over the 48 month period used to develop the availability of the coal plants, as shown in the following chart.



Q. How have you addressed this problem in your NPC adjustments?

A. I removed the Company's market caps in all of the major markets, except for the Mona market, allowing GRID to produce additional coal generation for sale into these markets. Adjustment 6 reflects this change to market caps.

CALIFORNIA ISO FEES

Q. What is the issue concerning California ISO fees?

A. The Company has included in the firm wheeling charges within NPC, fees paid to the California ISO to allow transactions between the Company and the California ISO. The fees include costs for grid management, reserve energy, congestion charges and charges to move energy through the California ISO grid. However, the connection between the Company and the California ISO is not included within GRID, so no transactions with the California ISO are included in NPC. Ratepayers are being asked to pay for access to a market that provides no benefit to ratepayers. Adjustment 7 removes the fees paid to the California ISO.

MORGAN STANLEY CALL OPTIONS

Q. Please describe the Morgan Stanley Call Options.

A. The Morgan Stanley call options are agreements the Company has struck in which the Company pays certain fixed costs in exchange for energy that is callable at a given strike price. The problem with the agreements is that the strike price is a relic of years past, in which market prices peaked at very high levels. There is no utilization of the purchase power in the test year, nor should there be, given the strike prices in these agreements. Ratepayers are being asked to pay for access to power that will likely never be utilized.

Q. What do you recommend?

A. I recommend the Commission not allow the fixed costs of the Morgan Stanley Call Options in NPC. My adjustment 8 removes these costs.

ARBITRAGE & TRADING MARGINS

Q. What are arbitrage and trading margins?

A. Given its wide geographical expanse, the Company has opportunities to purchase power at one location and simultaneously, sell the same power at another location, generating a margin. These are known as arbitrage margins. Trading involves purchases of electric futures that are (hopefully) sold at a profit at a later time.

Q. Are the Company's arbitrage and trading margins included in NPC?

A. The Company has included only [redacted] in margins derived from trading and arbitrage. Historically, from July 2006 through June 2010, the Company has enjoyed margins from these activities averaging approximately [redacted] million per year.[1] Given that ratepayers paid to construct the system that allows the Company to generate these margins, the actual average margins

[1] See the Company's response to OCS data request 20.1.

should be used to reduce NPC.

Q. Have other commissions ruled on this issue?

A. Yes, they have. The commissions in Oregon and Washington have ruled that actual average arbitrage and trading margins should reduce NPC. In fact, the Company has included these actual average margins in the NPC filed in Oregon Docket No. UE-227[2].

Q. What do you recommend?

A. I recommend that the Company's estimate of actual average arbitrage and trading margins be used to reduce NPC. My adjustment 9 accomplishes this result.

HEAT RATE DERATION

Q. Please describe the heat rate deration issue.

A. To account for unplanned outages on generating units, the GRID model reduces the maximum capability of generating units to reflect the unplanned outage rate. For example, if a 100 megawatt generating unit has an unplanned outage rate of 10% (is unavailable 10% of the time due to unplanned outages), GRID sees the unit as a 90 megawatt generating unit. This methodology assures that the unit will produce the correct amount of energy in GRID, but has the additional impact of improperly increasing the generating unit's heat rate.

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[2] See the Company's response to OCS Data Request 20.1.

Q. Why does this method increase the heat rate?

A. Generating units are most efficient (or have lowest heat rate) at maximum capability. In GRID, the deration of the unit to 90 megawatts causes GRID to utilize a less efficient heat rate, namely the heat rate at 90 megawatts rather than the heat rate at 100 megawatts. This is the problem that should be addressed.

Q. Why is this a problem?

A. If the unplanned outages are full unit outages (in which the generating unit is completely unavailable), the reality is that the unit would operate 90% of the time at full capability (100 megawatts) and would not operate at all 10% of the time. So the heat rate would be the most efficient heat rate that is achieved at 100 megawatts, rather than the less efficient heat rate at 90 megawatts. So GRID will improperly apply higher (less efficient) heat rates, causing the unit to consume excessive fuel.

Q. Do other problems arise from the capacity deration?

A. Yes. It has been argued that the minimum operating capacity of the generating unit should also be derated by the same percentage. However, this issue presents problems, such as allowing the unit to operate at lower levels than are physically possible. In any case, the dollar impact of the corresponding deration of the minimum capacity is very small.

Q. Was this issue addressed in the previous rate case?

A. Yes, it was. The Commission directed the Company, DPU, the Office of Consumer Services (OCS) and other interested parties to review alternatives to this issue, review actual operations in comparison to modeling predictions, and work to understand the extent of the issue[3].

Q. Did such meetings occur?

A. Yes. The DPU organized a phone conference including the Company and Randy Falkenburg representing the OCS. It was agreed that the Company and OCS would submit proposals for review by all the parties. However, only OCS provided a proposal – the Company did not.

Q. What do you recommend?

A. I recommend the heat rate curves in GRID be modified so that the generating unit heat rates at the maximum capability derated by the forced outage rate are the heat rates at maximum capability. Adjustment 10 accomplishes this result.

CHEHALIS RESERVE CONTRIBUTION

Q. What is the concern with the Chehalis reserve contribution?

A. The Chehalis combined cycle generating unit no longer provides reserves in the GRID model. That is, Chehalis no longer contributes to the reserve requirements in GRID. This was not true in the previous rate case.

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[3] See page 57 of the Commission's order in Docket No. 09-035-23.

Q. Why did the Chehalis reserve contribution change?

A. Chehalis is located in the Bonneville Power Administration (BPA) balancing area and on April 30, 2010, BPA rejected the Company's request for dynamic transfer capability due to Chehalis lacking Automatic Generation Control (AGC). According to the Company, this means that Chehalis can no longer provide reserves.

Q. Is there a cost to this change?

A. Yes, there is. I made a GRID run in which Chehalis was allowed to provide reserves. This one change reduced NPC by $3.4 million.

Q. Has the Company made clear the reasons for this change?

A. The Company has provided the correspondence with BPA, but it is not clear exactly why the situation changed in April 2010, nor is it clear that the Company has pursued all possible remedies.

Q. Is it common for combined cycle plants such as Chehalis to lack AGC?

A. No, it is not. Combined cycle plants are generally fitted with AGC so that the plants can be precisely controlled through the Company's dispatch center. The lack of AGC at Chehalis not only restricts the plant's ability to provide reserves, but limits the plant's ability to follow load, provide regulation and to operate economically within the system dispatch. According to Mr. Duvall, the Company must now "block schedule Chehalis prior to the hour"[4].

Q. What is block scheduling?

A. This means that the Company must select one level (such as 200 megawatts) and load Chehalis to that one level throughout each hour. Changes in generation within an hour are not allowed.

Q. Does this bring into question the economics of the plant?

A. This situation certainly reduces the value of Chehalis to the Company and ratepayers, if it cannot be corrected.

Q. Did the Company previously state that Chehalis would provide reserves?

A. Yes. In Docket No. 08-035-35, in which the Company requested approval to acquire Chehalis, Mr. Stefan Bird testified as follows concerning the characteristics of Chehalis:

> Ownership of the Plant allows the Company full discretion in the dispatch of the Plant. Energy from the Plant will be dispatched on a forward, day-ahead basis, with real-time optimization of the Plant's usage. Dispatch flexibility will give the Company an additional System resource with the ability to provide operating reserves, load-following reserves and

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[4] See line 4, page 20 of Mr. Duvall's rebuttal testimony in WUTC Docket No. UE-100749.

automatic generation control. This System flexibility will provide increasing benefit to the Company as load grows, the Company's existing flexible contracts expire, and the existing and planned wind resources added to the System to support existing and future renewable portfolios standards increase the Company's requirement for each of the operational characteristics provided by the Plant.[5]

Q. As things stand today, does the Company have full discretion in the dispatch of Chehalis, as claimed by Mr. Bird?

A. No.

Q. Can the Company perform real-time optimization of Chehalis?

A. No.

Q. Can Chehalis provide operating reserves?

A. No.

Q. Can Chehalis provide load-following reserves?

A. No.

Q. Does Chehalis provide automatic generation control?

A. No.

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[5] See page 6, lines 129-130 and page 7, lines 131-138 of the direct testimony of Stefan A. Bird in Docket No. 08-035-35.

Q. Will Chehalis assist the Company in providing additional flexibility as wind facilities are added to the System?

A. No.

Q. Does your GRID analysis reflect all of the currently existing limitations on the operation of Chehalis?

A. No, it does not. My GRID analysis only considers the loss of the ability of Chehalis to provide operating reserves. The block scheduling limitation on Chehalis and other limitations are not reflected in this GRID analysis. To my knowledge, GRID does not provide an option for block scheduling generating resources.

Q. What do you recommend?

A. The Company's NPC should be reduced by $3.4 million to reflect the value of reserves from Chehalis. In addition, the Commission should require the Company to estimate the impact of the other restrictions on Chehalis, and further reduce NPC by that amount.

Q. Does this complete your testimony?

A. Yes it does.