REDACTED VERSION

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. 08-035-38 DPU EXHIBIT 6.0

PRE-FILED DIRECT TESTIMONY

JAMES B. DALTON

ON BEHALF OF THE

UTAH DIVISION OF PUBLIC UTILITIES

February 12, 2008

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DIVISION OF PUBLIC UTILITIES

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

A. My name is James B. Dalton, and my business address is 160 E 300 S, Salt Lake City, 84114. My employer is the Division of Public Utilities (Division) in the Utah Department of Commerce. My current position is Utility Analyst.

Q. Do you have any attachments that you are filing that accompany your testimony?

A. Yes. DPU Exhibit 6.1 documents planned outage information for some of PacifiCorp's (the Company)'s thermal generation units. This exhibit contains proprietary Company information and is therefore marked confidential. DPU Exhibit 6.2 highlights forecasted declines in energy prices for calendar year 2009.

Q. Please describe your education and work experience.

A. I graduated with my Bachelor's degree and Master's degree from the University of Utah, both in economics. I began working for the Division in the fall of 2006. I provided testimony and appeared as the Division's witness on Net Power Cost issues in the previous rate case, Docket No. 08-035-93. In addition, I have thirteen years of experience in energy and natural resource management, planning, and policy analysis with the Utah Department of Natural Resources. As an Energy Analyst for the Utah Office of Energy and Resource Planning, I performed research and provided analysis on issues and methodologies dealing with Utah's energy supply, electric industry restructuring, forecasting, and benefit-cost analysis.

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

A. The purpose of this testimony is to identify and quantify adjustments to the Company's Net Power Costs (NPC) as proposed in the current Utah rate case. In this rate case, the Company now proposes a rate increase of $116.1 million reflecting the Utah Public Service Commission's (Commission) order in the Test Year hearing.

Q. What is the value that the Company has filed as a Total Company NPC for its calendar year 2009 test year?

A. As identified in the second supplemental direct testimony of Company witness Mr. Gregory N. Duvall (page 2, line 31), the Company's normalized NPC for the filed test year are approximately $1.053 billion, with approximately $420 million of these costs allocated to Utah.

Q. Please describe the adjustments that should be made to the Company's NPC figure.

A. At this time, the Division has identified six specific adjustments that reduce the Company's Utah allocated NPC figure by about $5.4 million. Each adjustment is listed below with the corresponding reduction.

Adjustment	Reduction
1. Adjust the imputed price of the SMUD contract	$ 652,473
2. Adjust planned outage dates in GRID	1,033,546
3. Revised forward price curve adjustments	2,554,765
4. Reduction of fuel costs at Bridger mine	541,843
5. Rolling Hills Wind capacity factor adjustment	209,516
6. NPC input errors, MDR 1.8	419,253
Total Recommended Reductions in NPC:	**$5,411,396**

In addition, the Division is currently reviewing additional NPC issues and may have additional adjustments or adopt adjustments of other parties at a future point in this proceeding.

Q. Please describe the Division's proposed NPC adjustment related to the Sacramento Municipal Utility District (SMUD) contract.

A. In its response to the Company's Petition for Reconsideration (Petition) filed under Docket No. 07-035-93, the Division supported the Company's request for reconsideration concerning the increased imputation of the SMUD contract price. In the petition, the Company argued that:

> …the Commission adopted a new and significantly higher imputed price related to a wholesale sales contract between the Company and SMUD—$58.46 per megawatt hour ("MWh")….The effect of the Commission's adjustment increasing the imputed price to $58.46 per MWh was to reduce system net power costs by $7.52

million and the Company's Utah revenue requirement by $3.287 million.[1]

In its reconsideration order, the Commission granted a reconsideration of this issue because of unresolved questions.[2]

Q. Where are the Division's arguments and recommendations concerning the SMUD pricing issue found in this docket?

A. They are contained in the Direct Testimony of DPU Witness Dr. William Powell, DPU Exhibit 9.0.

Q. What is the imputed SMUD contract price that Dr. Powell recommends?

A. He recommends that the imputed SMUD contract price be set at $41.56 for this filing.

Q. What are the NPC effects from this recommended price?

A. The new imputed price increases the current imputed price of $37/MWh to $41.56/MWh. Since this new recommended imputed price exceeds the accepted imputed price by $4.56/MWh, this would result in a $1,597,824 system-wide reduction in NPC ($4.56/MWh multiplied by the 350,400 MWh in contracted

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[1] Rocky Mountain Power, "Petition for Reconsideration," Docket No. 07-035-93, September 2, 2008, pp. 4-5.

[2] Utah PSC, "Order Granting Request for Reconsideration," Docket No. 07-035-93, September 22, 2008.

sales). This results in a reduction of NPC on a Utah-allocated basis of about $652,473.

Q. Please describe the Division's proposed NPC adjustment related to the Planned Outage dates included in the GRID model.

A. While it appears the Company has made efforts to model planned outages in off peak, lower cost periods, the Company can reduce net power costs further by bringing its planned outage dates in line with historic planned outage periods. This is particularly an issue for some of those thermal generation units that will not actually experience an outage during the test year, even though a normalized planned outage date input is included in the GRID model for the calculation of NPC.

Q. Can you show those units for which estimated planned outages are not consistent with historical data?

A. Yes. Confidential Exhibit DPU 6.1 shows the Company thermal units for which the GRID-modeled planned outage dates are significantly different from the actual historical planned outages that have occurred over the 48-month normalizing period ending June 30, 2008. This exhibit shows the frequency of total daily planned outages at each unit as they occurred in each month over the normalizing period. This clearly shows that for the plants identified, the related planned outage GRID inputs for calendar year 2009 vary from their typical outage period. Additionally, more than half of these plants will experience no actual planned outages during calendar year 2009, and for most of those that do have scheduled outages, the planned outage date in GRID does not match either the normalized historical period or the date when these actual outages are likely to occur.

Q. In general, if generation units are not expected to experience actual planned outages during the test period, why are planned outage dates included as input data into the GRID model for the calculation of NPC?

A. The Company assigns a planned outage date to each unit based on its average annual outages over a 48-month period. Using these historical data, the Company prepares a normalized planned outage schedule for each unit from which an annual NPC estimate for planned outages can be determined and allocated. Therefore, the respective date entered in GRID represents an average of allocated outages that occur from year to year.

Q. How was the Division's analysis developed?

A. The Division reviewed the Company's updated response to Master Data Request (MDR) 2.57 (2) to evaluate normalized planned outages for the 48-month period ending June 30, 2008 and compared these dates to the Company's forecasted planned outage dates for calendar year 2009, as contained in the GRID model. The Division's analysis aligns the planned outage dates in GRID with periods that are more consistent with historical data, as shown in Division Confidential Exhibit 6.1. The analysis takes care to make sure that the dates are within the

Company's preferred outage periods, as listed in its confidential response to DPU Data Request (DR) 41.6. These adjustments are congruent with the Commission's order on planned outages issued under Docket No. 07-035-93.

Q. What is the impact on NPC from adjusting these planned outage dates?

A. This adjustment results in a reduction to net power costs of about $2,404,415 system-wide or about $1,033,546 on a Utah-allocated basis. As net power costs decline when planned outage dates are aligned with historical data, this would indicate that such outages have typically occurred in periods in which planned outage costs are minimized.

Q. Please describe the Division's issues regarding fuel costs.

A. The Company based its net power cost estimates on the November 4, 2008 Official Forward Price Curve. The Division is concerned that with significant changes occurring in fuel prices for thermal resources, particularly for natural gas generation, the most up to date forward price curve information should be included in this filing.

Q. Why should this information be updated?

A. First, as the Division's analysis will show, prices for natural gas have dropped significantly since the issuance of the November 4, 2008 forward price curve, and are forecast to remain at current levels or decline even further during calendar year 2009. Secondly, in its testimony, the Company argues that updates of the forward price curve will increase the accuracy of the NPC forecast.[3] Given the dramatic economic changes that have occurred the past several months, the Division believes that updating forward price curve information at this stage is a prudent course of action.

Q. Can you describe some of the declines you mentioned in the cost of natural gas?

A. Yes. DPU Exhibit 6.2 shows how calendar year 2009 energy price forecasts have changed since November 2008. The forecasts shown in DPU Exhibit 6.2 are from various U.S. Energy Information Administration (EIA) Short-Term Energy Outlook (STEO) forecasts for nominal fuel prices. On average, the January 2009 forecast for 2009 monthly natural gas generation fuel costs are about 14.4 percent lower than the November 2008 STEO for 2009. EIA expects natural gas price decreases to persist through 2009. EIA points to significant decreases in the Henry Hub spot market price in the latter months of 2008 and indicated that this price could decline even further in 2009:

> The Henry Hub spot price averaged $9.13 per Mcf in 2008 but ended the year averaging $5.99 per Mcf in December. Weak natural gas demand associated with poor economic conditions together with strong domestic production growth contributed to the recent decrease in prices that is expected to persist in 2009. On an annual basis, the Henry Hub spot price is expected to average $5.78 per Mcf in 2009 and $6.63 per Mcf in 2010. As consumption reacts to worsening economic factors, natural gas prices may need

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[3] See Second Supplemental Direct Testimony of Gregory N. Duvall, p.4.

> to fall further than currently forecast in order to restrain production activities and balance the market during the second half of 2009, particularly as inventory nears storage capacity. Prices are expected to begin to increase in 2010 as the economy improves.[4]

Other forecasts support this analysis. In Platt's January 9, 2009 "Inside FERC's Gas Market Report," it was noted that because of ongoing declines in demand from worsening economic conditions, average U.S. market gas prices could dip below $4/mmBtu in early 2009 and could persist near these levels for several months.[5]

These trends highlight how natural gas prices have fallen since the period of time when the Company's November 4, 2008 forward price curve was developed. As a result, the Division believes that the Company needs to update its GRID model to include the most recent forward price curve for all its thermal resources. Without such updates, NPC estimates for calendar year 2009 are inaccurate and excessive.[6]

Q. Can you summarize the effects of declining natural gas costs on the Company's 2009 NPC estimate?

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[4] US EIA Website: "Short Term Energy Outlook, Highlights – Natural Gas Prices," http://www.eia.doe.gov/emeu/steo/pub/#Electricity_Markets

[5] Platts, "Inside FERC's Gas Market Report," January 9, 2009.

[6] Note that on February 10, 2009, Questar Gas Corporation (Questar Gas) filed a proposed $157 million decrease in rates. According to Questar Gas company officials, $90 million of this decrease is due to forecasted declines in natural gas costs over the next 12 months.

A. Yes. The Division and other intervenors requested the Company provide the most updated forward price estimates and show how fuel price forecasts have changed since the issuance of the second supplemental filing. The Company complied with this request and provided updated fuel prices and other related inputs in its GRID model to reflect more current price forecasts. These inputs integrate the most recent price information officially approved by the Company.[7]

Q. What was the result of these updates to GRID model inputs?

A. System-wide, NPC declined by about $5.9 million.

Q. Does the Division believe this to be a reasonable estimate?

A. Yes, as far as the GRID model calculated the results. However, the Division is concerned that the Company's gas hedging policies may result in overstated power cost estimates that are not an accurate reflection of actual market conditions. Moreover, it points out a need for the regulatory community to have a better understanding of the Company's hedging practices.

Q. You mentioned that the Company engages in gas hedging practices. What type of gas hedging practices does it employ?

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[7] Updated forward price data (as of December 31, 2008) and analysis are found in Company Response to UAE DR 2.1.

A. In its response to DPU DR 3.4, the Company noted that it uses two types of hedging strategies that affect NPC: "Mark-to-Market" for physical gas hedges and "Gas Swaps" for financial hedges.

Q. Will you please explain what the Division's specific concerns are with the updated forward price information?

A. Yes. In the Company's revised GRID run with updated price curve information, the Company's system-wide gas fuel burn expense decreased by $75,461,040, changing from $413,814,083 to $338,353,043, a decrease of approximately 18 percent.[8] These decreases appear to be a reasonable estimate of stated declines in market gas price forecasts. However, this decrease is almost entirely offset by increased costs from gas swaps.

Q. Can you please explain what a gas swap is?

A. Yes. A gas swap is a form of derivative. It is a financial instrument that the Company uses as a hedge against fluctuations in natural gas prices. In general, a commodity swap (such as a gas swap) is an agreement where one party agrees to exchange a floating or market commodity price with another party for a fixed price over a given time period.[9] Typically, the party using the commodity will

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[8] Compare Total Gas Fuel Burn data from Company Exhibit GND-1SS with Total Gas Fuel Burn data from Company response to UAE DR 2.1.

[9] Internet Website; The Financial Express "Some Basic Ideas About Commodity Swaps", originally posted June 11, 2007. http://www.financialexpress.com/news/some-basic-ideas-about-commodity-swaps/201454/

agree to pay a maximum price for a given quantity to a financial institution. In return, the commodity user receives payments based on the commodity's market price. At a specified point in the contract period, the two parties agree to "swap" an amount that is equivalent to the difference between the contract price and the floating market price multiplied by the purchased quantity. A swap is a purely financial arrangement in that there is no actual exchange of the commodity between the two parties. For example, assume the Company enters into a gas swap and agrees to pay a financial institution a fixed price of $6/mmBtu for the purchase of 1,000 mmBtu of gas, or $6,000. In return, the financial institution agrees to pay the Company the market price of gas for the given quantity. If the market price increases to $7/mmBtu at the specified payment period, the financial institution pays the Company $7,000. Therefore $1,000 ($7,000 - $6,000) is "swapped" to the Company from the financial institution in this exchange because it "hedged" against the increase in the market price. On the other hand, if the market price would have decreased to $5/mmBtu, the Company must pay (or "swap") $1,000 to the financial institution because the market price is $1/mmBtu less than the agreed-upon contract price. As with most financial instruments, there is also typically a transaction fee or some form of risk premium cost associated with the contract.

Q. Can you briefly explain what a "Mark-to-Market" hedge is?

A. Yes. A mark-to-market hedge is similar to a gas swap, except that the focus of the hedge is on how the purchase is valued from an accounting perspective. In this arrangement, the purchaser of a commodity enters into a contract to buy a physical amount of a commodity at a given price, and then takes delivery at some future time period on the expectation that the market price for the commodity will have increased. Assume the Company purchases 1,000 mmBtu of gas at a current price of $6/mmBtu. At purchase, the Company "books" this amount as $6,000, and agrees to take delivery at some future period. If the market price increases to $7/mmBtu at delivery, the "mark-to-market" value of that purchase is $7,000, and the Company accounts for that asset at that value. On the other hand, if the market price decreases to $5/mmBtu, the mark-to-market value is $5,000 at delivery.

Q. How are these hedges accounted for in NPC?

A. In its response to DPU DR 3.4, the Company noted that these hedging costs are calculated outside of the GRID model and are classified in two separate net power cost study line items: "Mark-to-Market" for physical gas hedges and "Gas Swaps" for financial hedges. Hedge data are entered as inputs in the GRID model "Other Costs" data series. Once entered, GRID compares hedged natural gas purchases to gas market prices, and adds or subtracts the additional costs or benefits of those purchases from the dispatch costs that are calculated at burner tip prices.

Q. How much did gas swaps increase?

A. In the Company's updated forward price GRID run, gas swaps increased by $75,193,355. In Company Exhibit GND-1SS, gas swaps totaled $80,070,048. They increased to $155,263,403 in the GRID run with the updated forward price information. This almost negates the savings in the gas costs, netting out as savings to customers of only $5.9 million (according to GRID) from a commodity cost savings of over $75 million. In other words, ratepayers will receive very little benefit from the significant decrease in projected gas costs. In general, in a declining fuel cost scenario, if full cost recovery of hedges is allowed, fuel cost risk effectively becomes the burden of the ratepayer with no corresponding benefit.

Q. Should the Division simply disallow the Company's Gas Swap estimates?

A. Not necessarily. With such a significant drop in prices over such a short period of time, it would seem natural to argue that these costs are imprudent. However, the Division understands that swaps or hedging policies are a two-edged sword. For example, in the July filing, there was to be an estimated [redacted][10] to total NPC from gas swaps that were hedged with forward prices estimated to be high in the July 2008 through June 2009 test year. Therefore, hedging practices may be beneficial in that they protect ratepayers from potential volatile increases

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[10] See Company Exhibit GND-1 (Confidential) from the Company's July filing under this docket.

in gas costs, such as those that were experienced in the market in mid-2008. Alternatively, ratepayers do not experience the benefit of lower power costs, because the Company is paying premium prices in times of sharply declining fuel costs.

Q. What does the Division recommend?

A. The Division is concerned that in spite of several inquiries into the topic of hedging, it remains a highly complex topic, the pros and cons are not clearly understood, and there appears to be no consensus or guidance on what constitutes prudent hedging practices. The Division is not recommending that the Company suspend hedging. As noted above, there is the potential for hedging practices to benefit both ratepayers and the Company. Similarly, the Division does not argue for complete disallowance of gas swaps in this filing because cost variances typically accompany hedging practices. However, the Division is concerned about the magnitude of these variances, and the risks that such occurrences may pose on ratepayers. Therefore, the Division recommends that the Commission open an investigation into Company hedging practices under a new docket to establish regulatory guidelines for prudent hedging practices with the objective of balancing risk and reward for both ratepayers and the Company.

Q. What is the Division's recommended adjustment to NPC when these forward price updates are run through the GRID model?

A. At this time, the Division needs to further review the updated information to determine whether the GRID inputs used to develop the Company's NPC $5.6 million adjustment are reasonable. As a result, the Division will adopt the Company's revised NPC estimate merely as a placeholder. Therefore, NPC are reduced by about $5.6 million decrease on a Company-wide basis, or about a $2.5 million decrease in NPC on a Utah-allocated basis.

Q. Can you comment on the Company's forecasted increases in coal costs?

A. Yes. In its second supplemental filing, the Company indicated that overall system coal costs increased by $14.6 million since the September 2008 filing. A large factor for this increase is due to higher mine operating expenses for the Company's Deer Creek and Bridger mines. While the Company argues that these increases are warranted despite the economic downturn, the Division believes that declines in fuel costs, reduced loads, and deteriorating economic conditions will negate some of the projected cost increases.

Q. Does the Division have any specific issues it is reviewing regarding these coal cost increases?

A. Yes. The Division recommends adjustments to the Company's forecasted diesel fuel, lubrication, propane/natural gas, and other energy-related costs at its Bridger Coal mining operation. The Division is also reviewing similar cost categories at the Company's Deer Creek mining operations. The Division is also concerned that coal contracts with variable fuel cost components should also be reevaluated.[11]

Q. Why should these costs be adjusted?

A. Because current forecasted costs for petroleum-related items have dropped sharply since the Company issued its forecasts in November 2008. DPU Exhibit 6.2 shows that average forecast 2009 prices for diesel fuel dropped by more than 24 percent from November. Likewise, crude oil price forecasts declined by almost 32 percent, and propane forecasts have dropped by more than 11 percent for 2009. The Company's estimated fuel costs at its mining operations are clearly higher than costs found in more current forecasts. For example, the Company estimated its 2009 diesel fuel costs at the Bridger mine at [redacted].[12] As of December 1, 2008, the date for which the latest EIA data are available, the average retail price for No. 2 diesel fuel was about $2.54.[13]

Q. The Company's Bridger mine uses significant quantities of these fuel items. What is the Company's projected cost estimates for diesel fuel, propane/natural gas, and lubricants?

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[11] Refer to "Contract Fuel Cost Assumptions," Company response to CCS DR 23.31-2, entitled "Utah General Regulatory Budget" (Confidential).

[12] Company presentation to Division staff: "Bridger Coal Company 2008 – 2010 Operating Summary," Dec. 18, 2008 (Confidential).

[13] U.S. EIA Website, "Weekly Retail Gasoline and Diesel Prices," February 3, 2009, http://tonto.eia.doe.gov/dnav/pet/pet_pri_gnd_dcus_nus_w.htm

A. According to the Company's confidential response to CCS DR 23.6 d-2, estimated diesel fuel costs for 2009 are about [redacted], propane/natural gas costs are about [redacted], and costs for lubricants are just over [redacted].

Q. Can you show what you are recommending as an adjustment to these costs?

A. Yes. The Division evaluated the Company's estimated diesel fuel, lubrication, and propane/natural gas costs at the Bridger mine, as shown in the Company's response to CCS DR 23.6. Based on the EIA forecasts, the Division de-escalated each of these cost categories by the corresponding percent decrease in forecasted prices in diesel fuel, crude oil (as an indicator for lubrication costs), and propane, as shown in DPU Exhibit 6.2. Specifically, the Division reduced estimated 2009 diesel fuel costs by 24.2 percent, propane/natural gas costs by 11.1 percent, and lubricants by 31.9 percent. This reduced the unit coal price from Bridger mine from [redacted] to [redacted].

Q. How does this reduction affect NPC?

A. As coal from the Bridger mine is used at the Jim Bridger plant, de-escalating these expenditure items lowered the plant's \$/mmBtu price. Using the adjusted \$/ton unit price, and aggregating this information with the other coal cost and consumption data as found in the Company response labeled CCS 23.6-b, the unit fuel price at Jim Bridger was reduced from [redacted] to [redacted].

Q. What is the impact when this reduced fuel price is run through GRID?

A. System-wide NPC decrease by about $1.24 million, or about $541,843 on a Utah-allocated basis.

Q. Is the Division performing a similar analysis for the Company's Deer Creek mining operations and for its variable cost coal contracts?

A. Yes. However, the Division has not completed its discovery process and lacks sufficient information to make a reasonable adjustment for these areas at this time. We may propose a similar adjustment for Deer Creek in our rebuttal testimony.

Q. Please describe the Division's issues regarding the Rolling Hills wind generation facility.

A. The Division is concerned that GRID underestimates wind capacities with the Rolling Hills wind generation facility.

Q. What is the Rolling Hills project?

A. It is a 99 MW wind farm consisting of 66 1.5 MW turbines located along an 11 mile ridge of the reclaimed Dave Johnston coal mine in Converse County, Wyoming. The Glenrock wind farm projects are generally located about one mile east of Rolling Hills at a slightly higher elevation.

Q. What issues are you raising with regard to the Rolling Hills wind project?

A. I am going to comment on the reasonableness of the 33.7 percent capacity factor the Company uses for Rolling Hills as part of its net power cost calculations for the current rate case.[14] My comments will include a discussion of the confidential reports prepared for the Company regarding the Rolling Hills project by CH2M HILL (Consultant) and the reaction last summer of the Oregon Public Utilities Commission (Oregon Commission OPUC) and its staff.

Q. Are you also going to deal with the prudency of the Rolling Hills project?

A. Not at this time. However, as more information becomes available, the Division reserves the right to make a determination on the issue of prudency.

Q. The Oregon Commission ruled that Rolling Hills was not a prudent acquisition. What is the Division's current position on this issue?

A. The Division has concerns that Rolling Hills may not be a least-cost resource. However, at this time we do not have sufficient information to reach a conclusion. Capacity factor is only one variable among others that might make a site economical. We invite the Company to show us why Rolling Hills is a prudent, least-cost acquisition.

Q. Please describe the CH2M HILL documents.

[14] The 33.7 percent average capacity factor is found in Company Exhibit GND-1SS.

A. CH2MHILL prepared two confidential "Technical Memoranda" for the Company, and addressed both to Mark Tallman, Vice President, Renewable Resource Development, for the Company.[15] The first Technical Memorandum is dated November 30, 2007 (2007 Report); the second one is dated August 14, 2008 (2008 Report).

Q. What were the results of the November 30, 2007 Technical Memorandum?

A. The 2007 Report concluded that Rolling Hills had an expected average net capacity factor (NCF) of [redacted] percent. These results were based on an average elevation of [redacted] meters above sea level, meteorological data from the Dave Johnston mine's meteorology station, with [redacted] years of data, and [redacted] meteorology towers set up to collect data specifically for the Glenrock projects that had data from [redacted] to [redacted]. The meteorological data suggested that the average temperature was about [redacted] degrees Celsius, which was adjusted downward by [redacted] degrees to reflect that Rolling Hills would produce more power during winter months, an average air density of [redacted] kg/m^3, and an average wind speed of [redacted] m/s (about [redacted] mph). CH2M HILL also estimated factors for turbulence, wind shear, terrain efficiency, and wake velocity deficits. The Consultant also estimated a wind speed uncertainty of [redacted] percent. CH2M HILL

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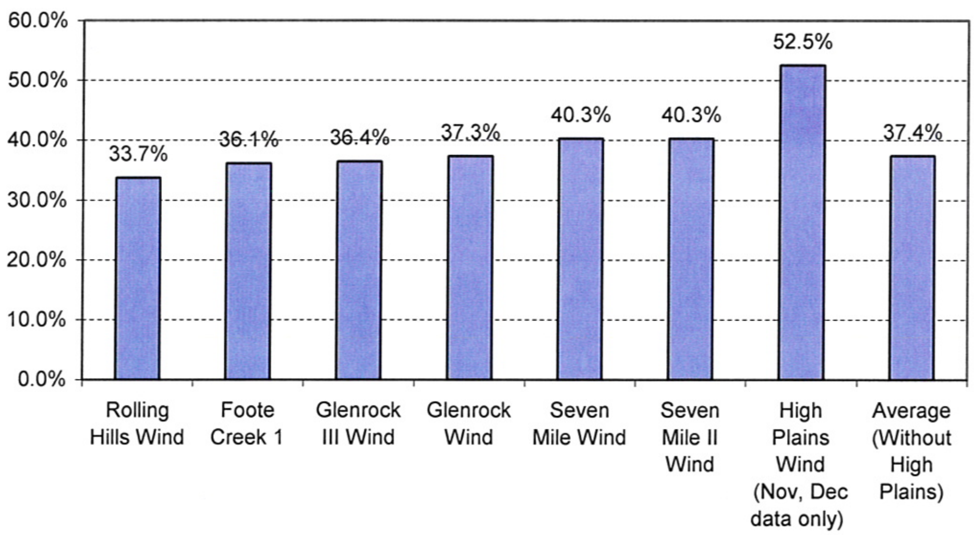
[15] The November 30, 2007 report was also addressed to Merrill Brimhall. The August 2008 report was addressed only to Mr. Tallman, but with copies to four other individuals, including Nick Rahn of PacifiCorp and three CH2M HILL employees.

also states that [redacted][16]

Q. How does the [redacted] percent net capacity factor compare with other Company wind projects in Wyoming?

A. It is noticeably below the others, which are all 36.0 percent or higher (see figure 1, below).

Figure 1: Estimated Wyoming Wind Capacity Factors, 2009
Source: Company Exhibit GND-1SS



Q. What is the effect on net power costs of this lower net capacity factor for Rolling Hills?

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[16] November 30, 2007 Report, page 1, "Summary of Findings."

A. It raises net power costs because, as there are no fuel costs associated with wind generation, lower estimated wind output results in greater energy demand for other, higher cost generation resources.

Q. What happened at the OPUC in the summer of 2008?

A. In a proceeding before OPUC regarding Oregon's Transition Adjustment Mechanism (a type of power cost adjustment procedure), OPUC staff witnesses Kelcey Brown and Lisa Schwarz in testimony dated June 23, 2008 opposed the Company's use of the [redacted] percent NCF and instead imputed 38.0 percent as the NCF.[17] The staff also asked, among other things, for a finding of imprudence on the Rolling Hills project.

Q. Why did they oppose the [redacted] percent NCF?

A. They believed that it was inadequately supported by site-specific data and was in contradiction to the higher results claimed for other Company wind sites in Wyoming.

Q. What was the basis of the 38.0 percent figure the OPUC staff advocated?

A. According to OPUC staff, it is the average NCF for the other PacifiCorp Wyoming wind farms.

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[17] Testimony of OPUC Staff Kelcey Brown and Lisa Schwarz in OPUC UE 199.

Q. What were the findings of the OPUC?

A. The majority of the Oregon Commission held that "[the Company] failed to prove that its acquisition of the Rolling Hills project was prudent. Costs attributed to [the Company's] Rolling Hills' project should not be recovered through the RAC [Renewable Adjustment Clause] mechanism."[18]

Q. Was the August 14, 2008 CH2M HILL report used in the Oregon process?

A. No. It seems to have been prepared following OPUC staff's challenge to the Rolling Hill's project mentioned above.

Q. What was the conclusion of the August 2008 Report?

A. The 2008 Report concluded that Rolling Hills had a NCF of [redacted] percent (vs. [redacted] percent in the 2007 Report). These results were based on an average elevation of [redacted] meters above sea level, meteorological data from the Dave Johnston mine's meteorology station and the [redacted] Glenrock meteorology towers mentioned above as well as [redacted] additional meteorological towers set up at Glenrock in December 2007. These additional towers provided [redacted] months of data for the 2008 Report covering [redacted] through [redacted]. The average temperature was about [redacted] degrees Celsius which was adjusted downward by [redacted] degrees to reflect that Rolling Hills would produce more power during winter months, and an average

[18] Public Utility Commission of Oregon, Order No. 08-548, entered 11/14/08, page 23.

air density that was now [redacted] kg/m^3. The 2007 Report had an average temperature of [redacted] degrees Celsius and an air density of [redacted] kg/m.[3] Wind speed seems to have been estimated for each turbine based upon its relative proximity to one of the meteorology stations. CH2M HILL also estimated factors for turbulence, wind shear, terrain efficiency, and wake velocity deficits. In the 2008 Report, there was no explicit estimate of wind speed uncertainty. In the 2007 report, however, the Consultant estimated a wind speed uncertainty of [redacted] percent. Among other discrepancies between the two reports, comparing Exhibit 17 in the 2008 Report with the similar Exhibit 5 in the 2007 Report reveals different sets of numbers that purport to be General Electric energy output data for its 1.5 MW turbines that are used in the Rolling Hills project for a [redacted] kg/m^3 wind density. In the 2007 Report, as wind speeds increase, the energy output from a turbine increases steadily, reaching its 1.5 MW peak at [redacted] m/s. In the 2008 Report, the output increases more rapidly and reaches its peak at just over [redacted] m/s.

Q. What are your conclusions?

A. The net capacity factor of Rolling Hills remains uncertain. While CH2M Hill [redacted]. Furthermore, the discrepancies between the two reports, some of the more significant ones are highlighted above, does not give the Division comfort at this time. However, it appears that generally the Rolling Hills site is inferior to other

Wyoming wind sites possessed by the Company. How inferior is yet to be determined. The Division proposes an adjustment to the NCF to 35.0 percent, which represents [redacted].

Q. Can you please describe the NPC impacts that occur by increasing the Rolling Hills capacity factor to 35 percent?

A. Yes. The Division adjusted the Equivalent Forced Outage Rate (EFOR) file in GRID for Rolling Hills wind based on the difference between the average annual 33.7 percent capacity factor, as found in Company Exhibit GND-1SS and the revised 35 percent factor. GRID models wind capacity by estimating EFOR rates for six periods each month during the year. The Division's approach allocated the average difference between the current 33.7 percent factor and the revised 35 percent factor equally across all 72 periods. This approach results in an average annual EFOR of about 0.647897, which yields a capacity factor of about 35.2 percent (1-0.647897). The result of this adjustment is a $504,741 decrease in system-wide NPC, which is equivalent to about $209,516 on a Utah-allocated basis. The Division continues to analyze this issue along with other related questions on wind, and therefore views this adjustment as preliminary.

Q. Do you have any other specific NPC adjustments that you plan to make at this time?

A. Yes. In its response to MDR- December 2008 Data Request 1.8, the Company identified several input errors in its NPC calculation for the calendar year 2009 test year. The Company lists the errors as follows:

- Non-Owned Generation: references to the month energy are off;
- Douglas County Forecast Product: amount of energy is overstated;
- Currant Creek weekend derate: reference to one weekend is incorrect;
- Kennecott QF purchase: amount of energy is overstated;
- Grant Surplus: generation is overstated in the second half of the last week that is partially 2010;
- Startup Costs: references to number of startups in some months are incorrect;
- Oregon Wind Farm purchases: energy prices should be by Heavy Load Hour and Light Load Hour; and
- Chehalis screen: the duration of the screen should be at least eight hours.

The Company argues that corrections to these errors will reduce NPC by about $1 million on a Total Company basis. The Company intends to make its corrections on rebuttal.

Q. Has the Division made its own adjustment to these errors?

A. No. The Division is still reviewing each of these errors to verify the impact. Therefore, the Division will accept the Company's $1 million adjustment as a preliminary estimate, and will likewise firm up this number on rebuttal. This would result in an NPC adjustment of approximately $419,253 on a Utah-allocated basis.

Q. Do you have any other specific NPC adjustments that you plan to make at this time?

A. No. The Division understands that other intervenors may file testimony on NPC. The Division will carefully review such filings. The Division reserves the right to adopt relevant NPC issues brought forward by any other party in this proceeding.

Q. Does this complete your testimony?

A. Yes it does.