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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-10-07**
MOUNTAIN POWER FOR	)	
APPROVAL OF CHANGES TO ITS	)	**Rebuttal Testimony of Hui Shu**
ELECTRIC SERVICE SCHEDULES	)	
AND A PRICE INCREASE OF $27.7	)	
MILLION, OR APPROXIMATELY	)	
13.7 PERCENT	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-10-07

November 2010

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

A. My name is Hui Shu, my business address is 825 NE Multnomah, Suite 600, Portland, Oregon 97232. My present position is Manager of Net Power Costs.

Q. Are you the same Hui Shu that submitted direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the adjustments proposed by intervening parties to the Company's filed net power costs ("NPC") in the current proceeding. These adjustments are proposed by Mr. Bryan Lanspery of the Idaho Public Utilities Commission Staff ("Staff"), Mr. Randall J. Falkenberg of the PacifiCorp Idaho Industrial Customers ("PIIC"), and Mr. Mark T. Widmer of Monsanto. In addition to my testimony, Company's witnesses Mr. Chad A. Teply addresses the adjustments proposed by Mr. Falkenberg and Mr. Widmer regarding the Lake Side outage, Colstrip outage and Naughton outages, and Ms. Cindy A. Crane addresses adjustment proposed by Mr. Falkenberg regarding the Jim Bridger fuel quality.

Recommendation for Company's Net Power Costs

Q. Has the Company made changes to its originally filed NPC?

A. Yes. The Company's system NPC has decreased from $1.07 billion in the original filing to $1.063 billion.

Q. What are the reasons why the Company's NPC decreased?

A. This decrease of $6.5 million reflects corrections and the Company's acceptance of certain adjustments proposed by Staff, PIIC and Monsanto.

Q. Please summarize the changes in NPC from your direct testimony.

A. Exhibit No. 71 summarizes the cost impact of the corrections and adopted adjustments that result in an NPC of approximately $1.063 billion on a total Company basis, which is $69.0 million on an Idaho-allocated basis.

Q. Do you have a general comment regarding the level of NPC that the Company has calculated and the adjustments proposed by other parties?

A. Yes. NPC and its components are volatile and inherently difficult to forecast. Actual operation lacks the same certainty and perfect foresight as the optimization model used to forecast NPC in regards to the variables and constraints, such as hourly load and market prices, availability of generation and transmission facilities, and weather conditions that impact the amount of hydro and wind generation. As a result, the actual operation/dispatch of the Company's resources may not necessarily achieve what the optimization model projects. That is, the model optimized NPC tends to understate the actual NPC that would be incurred for the same period. The Company's net power costs have increased significantly in recent years. With known changes in the Company's resource portfolio in the rate effective period, the normalized NPC in a historical test period further understates the costs that the Company prudently incurs to serve its customers. In the last general rate case, Case No. PAC-E-08-07, the Company agreed to NPC of $982 million, given the design of the test period. However, the actual NPC during 2008, which was the test period in that case, was $1.121 billion, and the actual NPC during 2009 when the rates were in effect was $1.022 billion. In the current case, the Company proposed NPC of $1,070 million that would be in effect during 2011. The Company's recent filing in Oregon Docket No. UE 216 has shown that the projected NPC in 2011 would be approximately $1,289 million. The preliminary results indicate that the Company's actual NPC through September are at approximately $859 million, or $1.129 billion for the 12-month period ended September 2010. Given the significant differences between what the Company proposed in this case and expected actual NPC in the rate effective period, it is unreasonable to make further adjustments to reduce the modeled NPC that will be used to set base rates beginning January 1, 2011, especially when the adjustments are as significant as the ones proposed by Staff, PIIC and Monsanto.

Q. The Commission has authorized an Energy Cost Adjustment Mechanism ("ECAM") for the Company. Doesn't the implementation of ECAM resolve the under-recovery risks of NPC?

A. No. As noted by Mr. Widmer the "review and determination of the appropriate NPC is very important because it represents one of the Company's single largest revenue requirement components and establishes the ECAM baseline."[1] The amount that the Company is authorized to recover under the ECAM is based on the differences between actual NPC and the base NPC included in rates during that period. Currently the Company's ECAM has a 90/10 sharing band. Because of the sharing band the Company is effectively limited to not recover all of the prudently incurred NPC in the rate effective period when actual NPC are

[1] Direct testimony of Mark T Widmer page 10 lines 14-16.

projected to be higher than what the Company proposes in the current case.

Company Responses to Specific Adjustments – Overview

Q. How have you organized your responses to the parties' modeling adjustments to NPC?

A. I have grouped the parties' proposed NPC modeling adjustments into three categories. First, there are adjustments to which the Company has agreed in whole. Second, there are adjustments to which the Company has agreed in part, or in response to which the Company has proposed a different position. Third, there are proposed modeling adjustments that the Company disputes as inaccurate, unsubstantiated, or inconsistent with normalized ratemaking.

Corrections and Adjustments Accepted in Whole

Q. Has the Company made any corrections since its initial filing?

A. Yes. After the initial filing, the Company has identified and provided in response to a Monsanto data discovery (Monsanto Data Request 2.33) three corrections:

- Dunlap was modeled without reserve requirements;
- STF transmission from southeast Idaho to northern Utah was not removed after the inclusion of the Populus to Terminal transmission line addition; and
- The UAMPS Use of Facilities wheeling expense should have been excluded

Correcting these three items increases the Company's system NPC by approximately $0.1 million.

Q. Has the Company accepted any adjustments proposed by Staff, PIIC or Monsanto?

A. Yes. The Company has accepted the following proposed adjustments:

- Commitment Logic Screens (PIIC Adjustment 1): As proposed by PIIC, the Company agrees to modify its daily screens consistent with the methodology set forth in the parties' stipulation in Oregon Docket UE 216. This change results in a decrease to system NPC of approximately $1.7 million. As discussed later in my testimony, the Company does not agree that this adjustment changes incremental O&M expenses included in the test year, as these expenses were not included in the test year.
- Inter-hour Wind Integration Costs of Non-Owned Resources (corrected PIIC Adjustment 4, and portion of Staff wind integration costs adjustment and portion of Monsanto Adjustment 2): The Company agrees to remove inter-hour wind integration costs associated with the wind projects that are located in the Company's balancing areas but do not deliver generation to the Company's system. PIIC's inter-hour wind integration adjustment needs to be corrected by removing the wind generation that the Company receives under contract with Seattle City and Light ("SCL"). This adjustment results in a decrease to system NPC of approximately $1.4 million.
- Colstrip Planned Outages (Monsanto Adjustment 8). The Company agrees to this adjustment that moves the timing of planned outages of the two Colstrip units from fall to spring. This reduces the system NPC by

approximately $0.2 million.

- Modeling of Mona Market (Monsanto Adjustment 14). The Company does not agree to the concept and logic of this adjustment. However, given the complexity around modeling all market caps in GRID, rather than selectively making adjustments to only one market for the selected time periods, the Company accepts the amount of adjustment proposed by Monsanto in the current case and will review the overall modeling of market caps in the future. This reduces the system NPC by approximately $0.4 million.

Adjustments Accepted in Part

APS Supplemental Adjustment (Staff's APS Supplemental Adjustment, Monsanto Adjustment 1)

Q. Please explain the issue raised by Staff and Monsanto with respect to the APS Supplemental contract.

A. Staff and Monsanto state that the Company's modeling of the APS Supplemental contract causes uneconomic dispatch of the contract, and the contract should be removed. The proposed adjustment would reduce system NPC by $1.9 million.

Q. Does the Company agree with the proposal?

A. No. Contrary to what Staff indicates as an inconsistency, the Company's modeling consistently reflects the fact that the Company has historically purchased energy from APS under the terms of the contract. It is not reasonable to arbitrarily remove this contract simply based on modeling results.

Q. Please describe the APS Supplemental contract.

A. The Company executed the Supplemental contract in 1990 with the Arizona Public Service Company ("APS") and has included it in NPC in Idaho since that time. Under the contract, APS makes available to the Company two categories of supplemental firm energy, coal ("APS Coal") and other ("APS Other"). At present, per the terms of contract, APS is obligated to offer the Company 219,000 megawatt-hours of firm energy on an annual basis priced at its incremental cost of coal generation, and 876,000 megawatt-hours of firm energy from other sources that are primarily natural gas-fired resources. The two categories of firm energy cannot be offered at the same time. APS is obligated to offer the energy, but the Company only takes the energy when it is economical to do so.

Q. Has the Company modified the modeling of the APS Supplemental contract in the current rebuttal filing?

A. Yes. The new approach to modeling this contract eliminates the increases to NPC when the contract is dispatched. The Company has aligned the timing and pricing of the deliveries with historic experience, rather than aligning the volume of deliveries with historic volumes, GRID now exercises the call option on the available energy when it is economical to do so. This change reduces the Company's filed system NPC by approximately $2.6 million.

Non-firm Transmission (Staff NF Transmission Adjustment, Monsanto Adjustment 3)

Q. Please explain Staff's and Monsanto's positions on the modeling of non-firm transmission.

A. Staff and Monsanto recommend that the Company should include non-firm transmission in GRID. Staff and Monsanto modeled non-firm transmission using a four-year historical average to adjust the capacity of links in the GRID model topology and using a dollar per megawatt-hour energy charge to calculate expenses. Staff's and Monsanto's proposed adjustments would reduce system NPC by $2.5 million and $2.4 million, respectively.

Q. What is the Company's response to Staff's and Monsanto's proposal?

A. The Company agrees to model non-firm transmission in GRID. However, if non-firm transmission is included in the model, it should be included on the same basis as short-term firm transmission. There is no basis for using a different method for non-firm transmission than for short-term transmission. Both types of transmission should be modeled using a four-year average to adjust the capacity links in the GRID model topology and the most current year of expenses.

Q. Please explain why non-firm transmission should be modeled the same as short-term firm transmission.

A. In the process of reviewing how the Company has utilized non-firm transmission, it is clear that the Company purchases and uses short-term firm and non-firm transmission in the same way. The transmission providers offer certain amount of transmission capacity as firm products, and the rest as non-firm. The only difference between the two products is that non-firm transmission will be cut first for reliability of the transmission system. For both short-term firm transmission and non-firm transmission, the wheeling expenses are incurred whether the transmission capacity purchased is fully utilized or not. As a result, the Company has modeled the non-firm transmission capability based on a four-year average of the historical purchases of non-firm transmission, and the expenses estimated based on what was incurred in the base period of the current filing.

Q. What is the impact on NPC of including non-firm transmission in GRID?

A. Including non-firm transmission using an approach that is consistent with the modeling of short-term firm transmission decreases system NPC by approximately $1.2 million.

Top of the World Wind (Monsanto 6)

Q. Please describe the adjustment proposed by Monsanto for the power purchase contract with Top of the World Wind.

A. Monsanto proposes to reflect the actual in-service date of the contract, which is one month earlier than what the Company has included in its original filing, but exclude the wind integration costs related to the wind generation. This adjustment would increase system NPC by $1.6 million.

Q. Does the Company agree with this adjustment?

A. Partially. In addition to the impact of additional purchase expenses, the additional wind generation would lead to additional wind integration costs, which is a subject that I will discuss later. Applying the same methodology as the Company applied for all other wind generation, the additional energy purchased from Top of the World Wind increases system NPC by approximate $1.9 million, including additional wind integration costs.

Company Responses to Contested Adjustments

Wind Integration Costs (Staff Wind Integration Costs Adjustment, PIIC Adjustment 5, Monsanto Adjustment 2, 2a and 2b)

Q. What have Staff, PIIC and Monsanto proposed with respect to the overall wind integration costs and the wind integration costs of the OATT customers?

A. Staff's proposal is to remove the entire amount of wind integration costs from the Company's filing, which would reduce the Company's system NPC by approximately \$34.2 million. PIIC proposes to remove the intra-hour wind integration costs associated with integrating non-owned wind projects that are interconnected to the Company's transmission system, which would decrease the Company's system NPC by approximately \$4.3 million. Monsanto proposes various versions of adjustments to the Company's wind integration costs, including the same proposal as the Staff to remove the \$34.2 million of the total wind integration costs, a similar proposal to PIIC is to remove the wind integration costs of the non-owned wind projects that would reduce the Company's system NPC by approximately \$6.4 million, or to include the wind integration costs for the portion of the test period that incorporated the actual wholesale transactions and reduce the Company's system NPC by approximately \$2.6 million.

Q. Do you see any basis to the proposals made by Staff and Monsanto to exclude the entire wind integration costs?

A. No. The proposals seem to be made based on three general arguments. First, the wind integration charge that the Company used is for setting avoided costs rates and not for setting retail rates. Second, the wind integration costs "are neither paid under contract or to any other utility." Third, the costs should be captured in the Company's ECAM. Their arguments to support their adjustments are contradictory and illogical.

Q. Please explain.

A. In Case No. PAC-E-09-07, after considering the Company's proposed wind integration costs and parties' positions on such costs, the Commission adopted a wind integration charge that was lower than what the Company proposed and authorized the Company to use $6.50 per megawatt-hour charge in determining its avoided costs for wind qualifying facilities in Idaho. Neither Staff nor Monsanto provides any evidence that would explain why this charge is appropriate to apply to wind qualifying facilities, but not appropriate to apply to Company-owned facilities or non-qualifying facility purchased power agreements. It is also unclear whether Staff or Monsanto is suggesting that by applying this charge, the prices for wind qualifying facilities located in Idaho are understated and whether the retail customers should pay more for the two qualifying facility contracts that are listed in Mr. Lanspery's testimony. While implying that the Company's wind integration costs are not real ("neither paid under contract or to any other utility"), Staff states that the Company's wind integration costs are captured in actual test period expenses and reflected in a number of accounts.[2] In addition, if the proposal of removing the wind integration costs from the Company's filing is

[2] Staff's testimony on page 5, lines 20 through 22 suggest that the reference to 2009 may need to be 2010. Otherwise, the discussion on a 2009 test period would be irrelevant in the current proceeding.

based on the fact that the wind integration costs are of significant size, difficult to calculate, and the Company may capture such costs in its ECAM filings, then the same argument may be made to the wholesale sales revenues: the Company's wholesale revenues are large, the actual amount of revenues in a year never matches the amount that has been projected, and as a result, the Company could use the ECAM filings to capture such revenues.

Q. Staff indicates that in the testimony requesting the ECAM, the Company stated that the ECAM was designed to capture the volatility, including the wind variability. How do you respond?

A. It is correct that the ECAM is designed to capture the volatility in NPC that occurs in relation to a properly set base NPC. However, the wind integration costs are not the same as the variation in NPC that the ECAM is designed to capture. Instead of addressing the variation between normalized and actual wind generation as the ECAM is designed for, wind integration costs are costs incurred due to additional reserve requirements to integrate the intermittent generation from the wind projects into the Company's portfolio of resources. The additional reserve requirements include regulating services that deal with wind variability in ten-minute interval, and load following services that deal with wind variability over hourly time intervals. Both services should respond to the up and down variations inherent in wind facilities. That is, the additional reserve requirements to integrate wind generation into the Company's resource portfolio takes on the forms of regulation up, regulation down, load following up and load following down.

In proposing to remove the wind integration costs, Staff never explained why such costs, which are reflected in a number of accounts, simply should not be part of the normalized studies, or at least not "explicitly". The Company could have modeled the wind integration costs "implicitly" by incorporating the additional reserve requirements in GRID, which would certainly lead to a value that is higher than $6.50 per megawatt-hour. The Company applied a simplified calculation using a Commission-authorized value that is lower than what the Company believes it to be in an attempt to minimize the controversy. In addition, since the ECAM is designed to capture the differences between actual NPC and the base NPC, the base NPC should reasonably account for all components, including the wind integration costs.

Q. Staff stated that the Commission has never expressly approved wind integration costs in any utility's general rate case. Do you believe that this is a precedent to follow?

A. No. The fact that the Commission has never expressly approved such costs does not mean that the costs do not exist or are not prudently incurred. The Company's wind resources have increased significantly in recent years. The subject of wind integration costs has received more and more attention in recent years. The Company is not the only utility that has recognized the cost impact of integrating wind generation into its resource portfolio. By allowing the wind integration costs charged by the Bonneville Power Administration ("BPA"), Staff and Monsanto agree that the Company prudently incurred wind integration costs in serving its customers at approximately $5.89 per megawatt-hour.

Q. One of Monsanto's arguments for removing wind integration costs seems to be the fact that the Company is unable to calculate its actual wind integration costs, and without knowing the actual costs "it is very difficult to determine the reasonableness of Company's requested recovery." How do you respond?

A. First of all, as Mr. Widmer is aware, the Company operates its resource portfolio to serve all its obligations, and does not differentiate what resources are used for serving which obligations. As such, the Company can only estimate the impact of wind integration costs. Second, if Mr. Widmer is looking for references to check if the Company's wind integration costs are within reasonableness, he only needs to look at the wind integration charge that BPA imposes, the wind integration study that the Company used in proposing wind integration costs for avoided costs, wind integration costs that he quoted in his testimony from the Company's last Integrated Resource Plan ("IRP"), and the wind integration costs of $6.63 per megawatt-hour that were approved by the Public Service Commission of Utah in the Company's last general rate case Docket No. 09-035-23.

Q. Why do PIIC and Monsanto propose disallowing intra-hour wind integration charges associated with non-owned wind facilities in the Company's balancing areas?

A. PIIC argues that the Company should not include the wind integration costs incurred by providing wind integration services to the non-owned wind projects because the Company does not have a transmission tariff to recover the costs from those customers. The proposal would reduce system NPC by $4.3 million. As a secondary proposal, Monsanto also proposed the same adjustment, which would reduce system NPC by $6.4 million.

Q. Are there any errors in the adjustments by PIIC and Monsanto?

A. Yes. The adjustments proposed by PIIC and Monsanto are both incorrectly calculated because, in addition to generation from the non-owned wind projects, their adjustments exclude the generation under the contract between the Company and SCL. Per the terms of the contract, the Company receives wind generation from the portion of the Stateline wind project owned by SCL and then returns firm and shaped energy to SCL. In addition, Monsanto's adjustment also includes an adjustment for inter-hour wind integration for the wind projects that are located in the Company's balancing areas that the Company has interconnected.

Q. Why doesn't the Company charge wind generators for wind integration costs that are located in the Company's balancing areas but do not provide generation to the Company?

A. The Company could not charge wholesale transmission customers for this type of service without FERC approval of a rate application proposing a new wind integration charge. The Company is required by federal law to interconnect with new facilities under the terms of its Open Access Transmission Tariff ("OATT"). Once the Company interconnects a new facility to its transmission system, it is responsible for integrating it into the system.

Q. Are there barriers to charging non-owned wind facilities for wind integration costs?

A. Yes. Modifying the Company's OATT to impose wind integration charges on only non-owned wind facilities would violate the federal statutory mandate that the Company treat all transmission customers, affiliated and non-affiliated, on a not unduly discriminatory basis. In addition, there is little regulatory guidance from FERC in this area with respect to what FERC will ultimately consider to be an adequate proposal for a wind integration charge. Although FERC conditionally accepted a proposal by Westar to add a new Schedule 3A charge, whereby all variable generators located within Westar's balancing area pay a regulatory service fee for power exported outside of the balancing area, recently, FERC rejected Puget Sound Energy's proposed revision to its OATT to add a new charge applicable to all wind generators for wind integration within-hour generation following service. In each case, wind industry advocates vigorously protested the proposed tariff revisions because, among other issues, the proposed charges constituted significantly higher regulatory service fees to intermittent resources than for dispatchable resources.

Q. Does the Company plan to raise this issue in its next FERC rate case?

A. Yes. The Company plans to file a rate case with FERC no later than June 1, 2011, in which the Company will include a proposed wind integration charge in its transmission tariff rates pending any FERC guidance on the issue. The Company completed a wind integration study in conjunction with its 2010 Integrated Resource Plan and is in the process of reviewing comments from parties regarding the study. It is hoped that the study can be used in the development of a wind integration charge proposed to be added to the OATT, however, no determination has yet been made. The Company is closely tracking all developments at FERC related to wind integration and is bound to follow any guidance FERC may issue in this regard.

Q. Are the costs associated with wind integration a prudent expense?

A. Yes. As a balancing area authority, the Company must operate its balancing areas by matching system resources to actual load and generation fluctuations on a moment-to-moment basis through automatic generation control. Maintaining system balance is one of the key functions of a balancing area authority who is required to maintain system reliability, including maintaining system frequency. Load fluctuations, outages, and generation output fluctuations all contribute to the need for balancing resources. The addition of renewable resources such as wind has the tendency to increase the need for balancing resources.

Q. What are the benefits to the Company's retail customers of providing such services to the non-owned generation?

A. As a balancing area authority, the Company owns and operates an extensive transmission network that it is required to operate safely and reliably for all of its customers, keeping all resources and loads in balance on a moment-to-moment basis. By providing wind integration services in addition to other transmission related services as a balancing area authority, the Company ensures that its customers are served by a reliable system with diverse resources. Moreover, any transmission revenues received from non-owned generation, which pays wheeling to the Company, are credited against retail rates and therefore have the effect of lowering retail rates.

Q. What adjustment does Monsanto propose to the Company's inter-hour wind integration costs?

A. If the Commission does not agree with Monsanto's proposal to remove the entire wind integration costs from the Company's filing then Monsanto proposes a secondary adjustment. Monsanto claims that the inter-hour wind integration costs for balancing purposes have already been included in the Company's filing through the inclusion of actual short term firm transactions, and by calculating the inter-hour wind integration costs for the period from January 1 to May 4, 2010, the Company double counted the wind integration costs. The adjustment would reduce Company's system NPC by $2.6 million for inter-hour wind integration costs from January to April.

Q. What is your response to the proposal?

A. I don't agree with the proposal. Monsanto's own arguments present contradictions. On one hand, Mr. Widmer claims that the inter-hour wind integration costs have been included for the first four months of the test period because the Company has included actual short term firm transactions through that period. Then on the other hand, Mr. Widmer also agrees that "[t]he Company has a variety of options for balancing," and these options include redispatch of all flexible resources, firm and non-firm wholesale contracts, generation and wind curtailment. The Company has included actual short term firm transactions in its filing. However, those transactions are only a small portion, if any, of the resources that the Company utilizes to integrate generation from wind facilities into its system. In its filing, the Company has included wind generation at the expected level that lacks the significant variability as in actual generation. As such, the generation from all other flexible resources is also at the level that does not reflect the impact of the significant variability in actual wind generation and the costs of integrating such generation into its system.

Q. Are there other problems with Monsanto's proposal?

A. Yes. While not accepting the Company's wind integration costs at $6.50 per megawatt-hour, Mr. Widmer uses the Company's wind integration at $6.92 per megawatt-hour as a reasonable approximation to split the intra-hour and inter-hour wind integration costs. In addition, it is unclear what Mr. Widmer implies by stating that further adjustment could be made to what he has proposed in relation to various other means. If the reference were to the flexible resource indicated above, the Company's NPC in the proceeding has not considered the impact of significant fluctuation in wind generation on other resources because they are all modeled on a normalized basis. If the reference were to the additional sales transactions that the Company could make, Mr. Widmer would be double counting the presumed impact that he calculated based on short term firm transactions, which would have included both sales and purchases.

Q. What do you recommend the Commission do regarding various proposals to remove all or portion of the wind integration costs that the Company has included in the case?

A. With the exception of inter-hour wind integration costs discussed earlier in my testimony that the Company agrees to remove, the Commission should reject all other adjustments proposed by Staff, PIIC and Monsanto.

Bear River Hydro Normalization (Staff Bear River Hydro Generation Adjustment, Monsanto Adjustment 12)

Q. **What was the issue on the Bear River normalization?**

A. The Company modeled the normalized generation from the Bear River system based on history, excluding the flood control years. Staff and Monsanto argued that the Company should not have reduced hydro generation from the Bear River system based on long-term drought conditions on the Bear River, and recommend using the historical average generation from the Bear River system. The adjustments would reduce the Company's system NPC by $2.2 million.

Q. **Does the Company agree with Staff and Monsanto's argument?**

A. No. The water available for generation at the Bear River facilities is dependent on contractually specified irrigation and flood control releases from Bear Lake. Flood control on the Bear River is an operational constraint and releases of water for flood control have not been available to the Company since 2001. The usual manner of normalizing hydro requires adjustments for operating constraints.

Q. **Please explain the contractual controls over discharges of water from Bear Lake.**

A. Those contractual controls include: (1) The 1958 Bear River Compact approved by the United States Congress which prohibits the release of water from Bear Lake solely for power generation below the irrigation reserve level of elevation 5,914.61 feet; (2) the 2000 "Operations Agreement for PacifiCorp's Bear River System," which requires that the Company operate Bear Lake primarily for irrigation and flood control. This agreement was required by Idaho, Wyoming, and Utah as a condition for approving MidAmerican Energy Holdings Company's acquisition of PacifiCorp; and (3) recently, the Company began modeling the impact of the new operating constraints required by the 2003 license for FERC Project #20, including the Grace Plant on the Bear River system, which mandates increased bypass flows below Grace dam for ameliorating fisheries and aquatic issues and to provide recreation opportunities (e.g., white water boating). Water released into the river channel below the dam bypasses the turbine and cannot be used for generation. This alone reduces total generation available from the Bear River by an estimated 19,000 megawatt-hours.

Q. Please provide background on how the Company modeled Bear River generation in the last case.

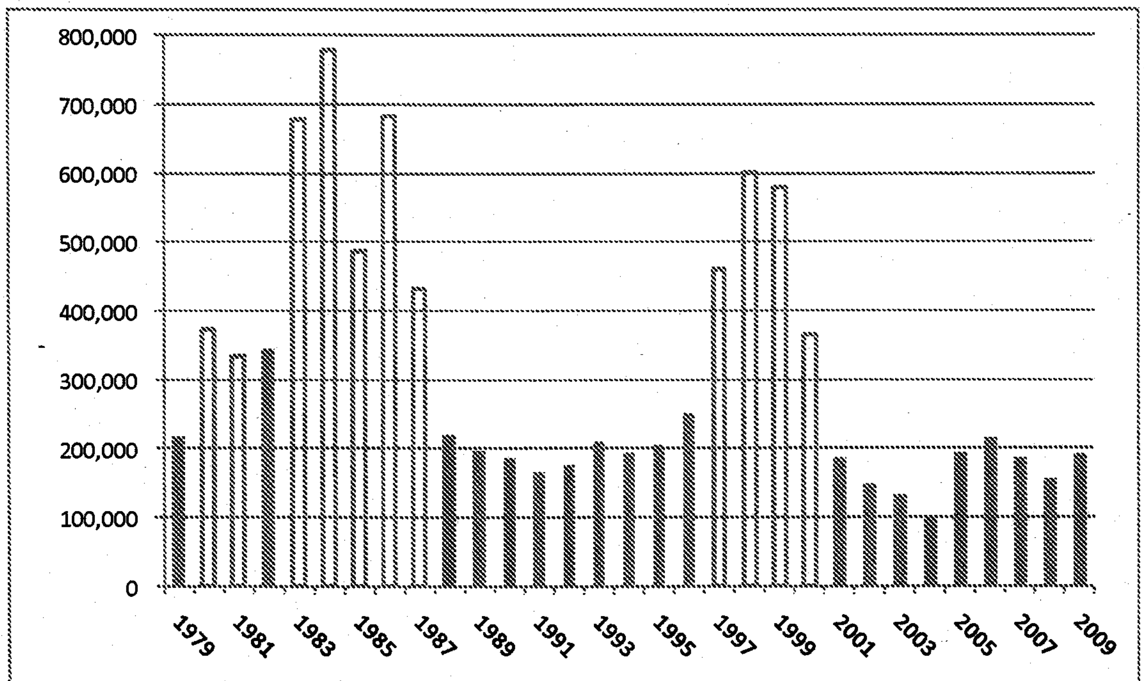
A. The dams on the Bear River have three potential sources of water for generation: natural inflow, water withdrawn from Bear Lake to supply downstream irrigators, and water withdrawn from Bear Lake for flood control purposes. The Company's operating agreements for the Bear River system referred to above prohibit the Company from withdrawing water from Bear Lake for generation and flood control purposes unless the lake elevation exceeds a certain level. For the past 10 years, and for the foreseeable future assuming median streamflow into Bear Lake, this operational constraint has and will prevent the Company from operating the Bear River system with flood control releases. The lake elevation is projected to drop to about 5,910 feet at present, which is 11 feet below the 5,921 feet elevation level that allows the Company to release flood control storage.

The Company previously modeled the Bear River system using historical normalized hydro generation for all three operational modes that included water supply from natural run-off, irrigation deliveries, and flood control releases, without considering the operational constraints around flood control operations. After a careful review, the Company concluded that the flood control mode of operation has now effectively become unavailable, and the Company has begun accounting for this operational constraint in its rate filings and operations planning by excluding the generation using the flood control water in its normalized hydro generation.

Q. What has been the generation from the Bear River system in the recent history?

A. Figure 1 below shows the actual generation from the Bear River system from 1979 to 2009 water year (October of the previous calendar year to September of the current year), which is the base period applied in the current proceeding. The unshaded bars identify the flood control years. It is clear that the generation during the flood control years is significantly higher than the non-flood control years. The actual generation through 2010 is also added to the Figure.

Figure 1 Actual Generation from Bear River

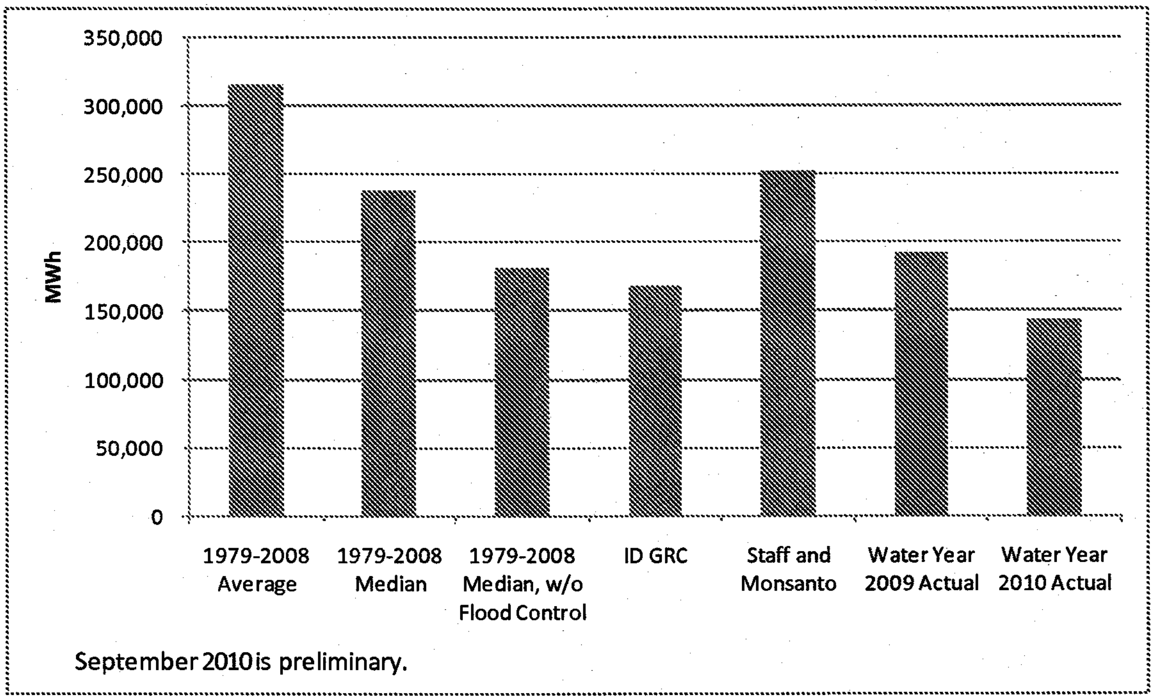


September 2010 is preliminary.

Q. How does the normalized hydro generation from the Bear River system compare with actual generation?

A. Figure 2 below shows the comparison of historical generation that is unadjusted for any known and measurable changes, such as rules and regulations, over the years, normalized generation in the current proceeding as proposed by the Company and by Staff and Monsanto, and the most recent actual generation. It is clear that the normalized generation in the Company's filing is more representative of the expected generation from the Bear River system.

Figure 2 Bear River Generation Comparison



Q. What then is the consequence of adopting Staff and Monsanto's proposed adjustment for Bear River normalization?

A. Adopting Staff and Monsanto's proposal would lead to overstating hydro generation, and understating NPC as a result of not incorporating this operational constraint in normalizing historical generation. I recommend the Commission reject the adjustment proposed by Staff and Monsanto.

Start Up Energy (PIIC Adjustment 2)

Q. Please explain PIIC's proposal for the value of start-up energy.

A. PIIC proposed that the Company include the energy associated with starting up Currant Creek, Lake Side, and Chehalis in NPC because the fuel costs of start-ups are included in NPC. The adjustment would decrease the Company's system NPC by $1.7 million.

Q. **What other costs are incurred when starting up the gas-fired plants?**

A. Start-up costs are not limited to fuel. In order to accommodate the start-ups of a 500 to 600-megawatt gas unit, the Company must re-dispatch the system. In doing so, the Company incurs costs beyond what it would have incurred had the start-ups not occurred. These costs could result from ramping down the lower-costs hydro and thermal units to lower efficiency levels, and increasing generation from higher-cost units prior to when they are needed. None of these costs are included in GRID.

Q. **Did PIIC's proposal contain technical errors?**

A. Yes. In calculating the value for the start-up energy, PIIC violated the requirement of the minimum down time required for units to stay offline before returning to service. This is due to the fact that GRID allows units to start instantaneously. However, if start-up energy is to be considered, the multi-hour start-up sequence must also be considered. The end result is that the units would need to stay offline and be unavailable for a longer time in order for PIIC's adjustment to be even applicable. The prolonged downtime would lead to increases in NPC by approximately $4.7 million from what the Company included in its original filing on a total Company basis, which offsets the $1.7 million assumed value of the start-up energy. As a result, I recommend the Commission reject PIIC's adjustment.

Normalization of Call Option Contracts (PIIC Adjustment 3, Monsanto Adjustment 13)

Q. What were the adjustments that PIIC proposes to the modeling of the SMUD sales contract and Monsanto proposes to the modeling of the Black Hills sales contract?

A. PIIC proposes to substitute actual data for normalized data for the sales contract with the Sacramento Municipal Utility District ("SMUD"), and Monsanto proposes similar adjustment for the sales contract with Black Hills Power ("Black Hills"). The adjustments would reduce the Company's system NPC by $1.6 million and $1.3 million, respectively.

Q. Do you have any general comments about the two proposals?

A. Yes. For normalized purposes, the GRID assumes that the counterparties – who control the call options on these two contracts - will maximize the value of the contracts and take power at the most economical time. GRID assumes optimization of all flexible resources, while PIIC's and Monsanto's proposals embody an approach of optimizing flexible resources when it lowers NPC and not optimizing flexible resources when it raises NPC. It was based on the assumption that the Company acts rationally and other companies act irrationally. PIIC's and Monsanto's proposals violate any reasonable principles of consistency and fairness. If NPC are to be set using an optimization model, then all resources and contracts that are subject to being optimized should be optimized. This is the same argument used by Staff and Monsanto in their proposed treatment of the APS Supplemental contract where they propose that actual historic energy take under the contract should be rejected in favor of optimizing the contract in GRID.

Q. Please explain.

A. The proposed adjustments depart from modeling power costs on a normalized basis. If this type of modeling adjustments were adopted, then consistency and fairness require its application to all other flexible purchase or sale contracts that are modeled in a similar fashion to the SMUD and Black Hills contracts. For that matter, it should also be applied to flexible generating resources. Optimization of the Company's system operations decreases NPC on a net basis. PIIC and Monsanto have not proposed "de-optimization" across the board, which would increase NPC. Nor have PIIC and Monsanto provided any justification for selective "de-optimization" of only two call option sales contracts, rather than all purchase and sale contracts and flexible generating units.

Q. Why is it important to treat third party contracts the same whether the Company is selling or purchasing energy?

A. Use of any delivery patterns other than the optimized delivery patterns will always lower net power costs for wholesale sales contracts with flexibility such as the SMUD and Black Hills contracts. The opposite is true for purchased power contracts that give the Company flexibility in how the power is taken. It is not fair or consistent to normalize different contracts using different rules.

Q. How do you respond to the arguments made by PIIC and Monsanto that flexible wholesale sales contracts should not be optimized because the Company has not modeled any of the loads, constraints, or forward price curves used by the counterparties?

A. It is correct that the Company does not model the counterparties' systems due to the impossibility of obtaining the data that are proprietary to those counterparties. However, given that the Company is only one of the many participants in the market, the only assumption is to assume that all the participants in the same market are rational and will exercise their rights to the flexible contract to lower their costs. This is confirmed by Black Hills as presented on page 2 of Exhibit No. 72, which was an exhibit to Mr. Falkenberg's testimony in the Company's 2009 Wyoming general rate case, Docket No. 20000-352-ER-09[3], where it states: "BHP will capture the maximum contract value by taking delivery of the contract energy to serve load or facilitate market sales." This is exactly what the Company's method of optimization captures, and what is demonstrated in Exhibit Nos. 73-75. Exhibit No. 73 shows the actual delivery taken as a whole, and that the pattern of this energy delivery may appear to be flat. However, looking at the same data, but by HLH and LLH and by location where the energy was delivered in Exhibit Nos. 74 and 75, it is clear that Black Hills exercised their rights based on price signals from the market, taking more energy when and where market prices were relatively higher.

[3] Both Mr. Falkenberg and Mr. Widmer were consultants to Wyoming Industrial Energy Consumers ("WIEC") in that proceeding.

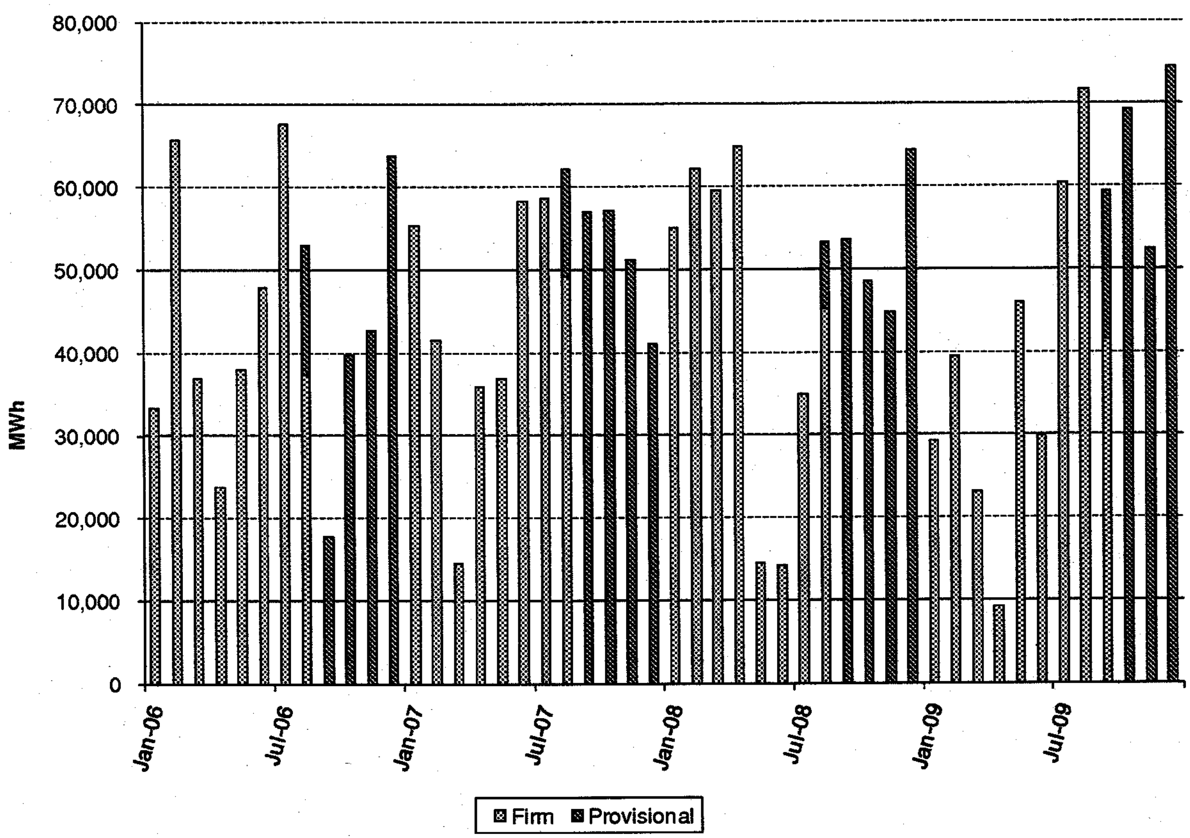
Q. How is the SMUD contract structured?

A. In addition to the firm energy component that is modeled in GRID explicitly, SMUD also has the right to take provisional power from the Company under the terms of the same contract, which will be returned in full to the Company next year. For the normalized calculation, the Company assumes the take and return of the provisional power are equal and matching in the test period.

Q. Does the historical data display SMUD's preference on when to take energy under the contract?

A. Yes. When both of these are taken together, it is clear that SMUD intends to take energy with preferences by season. Figure 3 below shows the monthly pattern of the total firm and provisional sales in a four-year period. Based on the historical pattern, it would be reasonable to assume that without the flexibility of the provisional portion of the contract, SMUD would shape their take of the firm portion with a similar seasonal pattern. PIIC's proposal only considers the firm portion of the contract, and suggests that SMUD would take more energy in spring than in fall as if SMUD would not have considered their rights to the provisional energy.

Figure 3 Historical Shape of Energy Take by SMUD



Q. Does the Company model any contracts based on actual historical data?

A. Yes. The Company models non-flexible contracts, such as the ones with GP Camas, Biomass, and small purchases, based on historical information because none of these contracts provide the Company the kind of flexibilities that are provided for under the terms of the call option sales contracts. Based on the principle of known and measurable information, the only information known to the Company is the history of those contracts. I recommend the Commission reject the adjustments proposed by PIIC and Monsanto on the basis that the adjustments violate the fairness in the optimization of all flexible resources to reduce NPC.

Heat Rate Deration (PIIC Adjustment 10)

Q. What does PIIC's propose in this adjustment?

A. PIIC claims that the Company's application of outages biases the availability and average heat rates of the units. The adjustment proposed by PIIC would reduce Company's system NPC by $1.8 million.

Q. How does the Company apply the deration method?

A. The Company's approach derates the maximum capacity of the unit in every hour of the year by an equal percent based on historic forced outage rates, which constitutes a "haircut" in unit availability.

Q. How would PIIC's discussion change this method?

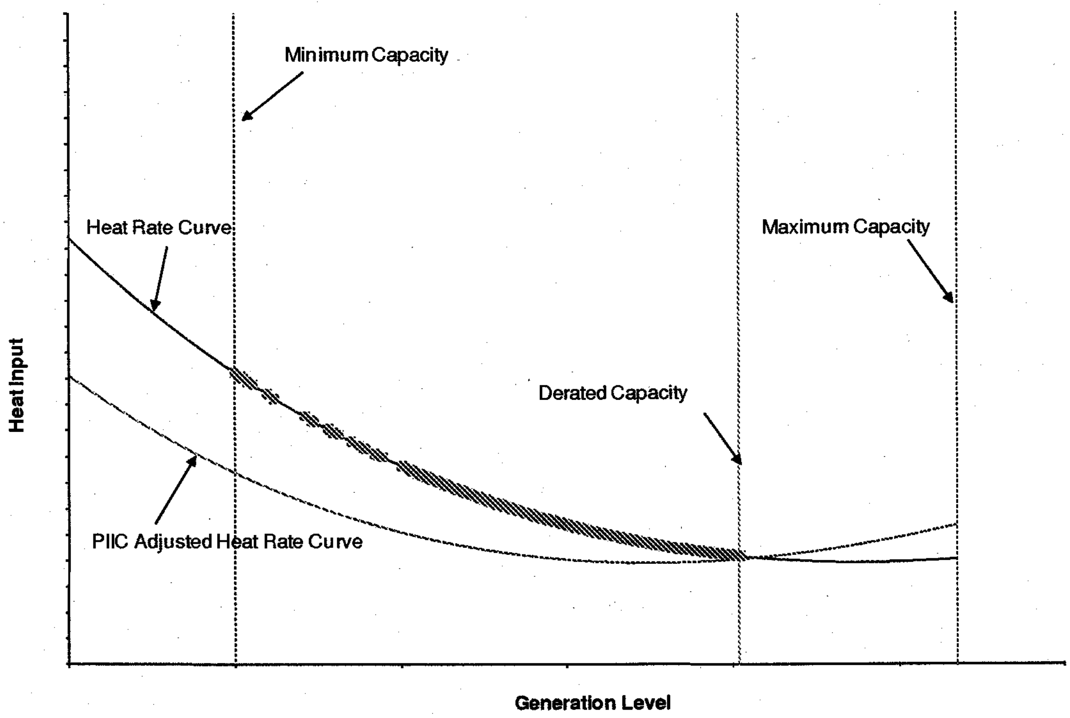
A. The discussion presented by PIIC would alter thermal units' heat rate curves to artificially increase their efficiency as compared with the heat rate curves that are developed from actual plant operating data. The discussion on the "other aspect" of the problem that PIIC presents is to reduce thermal plant minimum generation levels so GRID can run thermal units at levels they are physically incapable of reaching.

Q. Would PIIC's method significantly understate the heat rates?

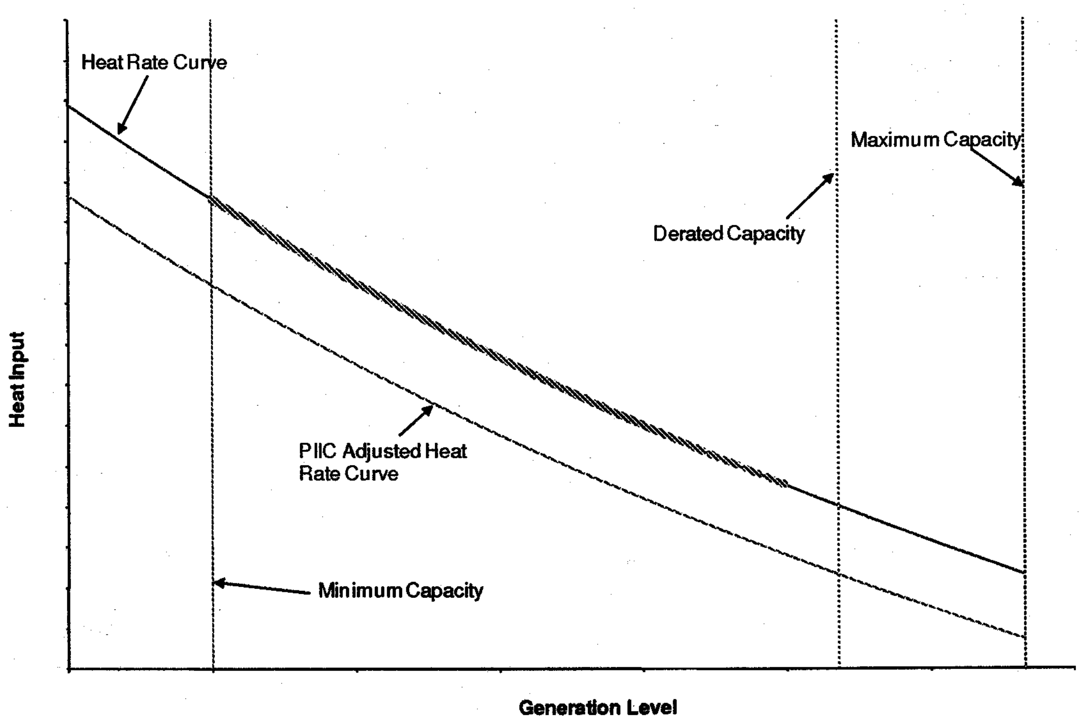
A. Yes. The only time when the derate adjustment to the heat rate may be applicable is when the unit is dispatched at one particular level of generation – its derated maximum capacity, with the assumption that the unit may be dispatched at its stated maximum capacity in GRID if there were not the availability "haircut". When the unit is dispatched at any level below its derated maximum capacity, GRID has made the optimal decision to dispatch that unit at a lower and less efficient generation level, whether it has been derated or not. Therefore, derating the entire heat rate curve overstates the efficiency of the unit and understates the heat inputs.

Figure 4 and Figure 5 below show the heat rate curves that would be under the methods modeled by the Company and modeled by Mr. Falkenberg in the Company's previous cases in other jurisdictions for a coal-fired unit and gas-fired unit, from minimum to maximum generation level, with the assumed generation levels superimposed on the heat rate curves that would be dispatched under the Company's methods. The graphs clearly demonstrate that heat input required for various levels of generation is understated using the derate-adjusted heat rate. In both cases, there are many hours of dispatch below the derated maximum capacity, which are the generating levels at which PIIC's proposal would understate the heat rate, and subsequently understate NPC.

1 **Figure 4 Heat Rate Curve (Coal Unit)**



2 **Figure 5 Heat Rate Curve (Gas Unit)**



Q. Hasn't the Company agreed to adjust the heat rates at least to the derated maximum capacities of the units as claimed by PIIC?

A. No. The Company believes that the only adjustment that may be valid is at units' derated maximum, assuming that the unit could generate at a slightly more efficient level, but the Company does not believe such adjustment should be made. After the Company's application of the "haircut," the units' capacities are still at relatively efficient levels. In actual operations, a unit can be derated to any level between its minimum and maximum capacities, and from Figure 4 and Figure 5, the heat rate at lower levels are significantly less efficient than at the derated maximum.

Q. Do you agree with PIIC's discussion that the minimum generation level should be derated because the maximum generating level is derated?

A. No. The purpose of the "haircut" to the maximum generating capability is to reflect the amount of generation no longer available due to outages. That is fully accomplished through the "haircut" to the maximum generating capacity.

Q. PIIC relates the proposal of making duration adjustment to the Company's modeling of fractionally owned units. Do you have comments on that?

A. Yes. PIIC seems to suggest that the portion of the units that would not be available due to outages may be considered to be owned by other entities. Such concept would require the modeling of all aspects of the units in the same manner, including the reserve capabilities of the units. In addition, in the case of outages, it is not correct to assume that another entity owns the portion of the units that are forced out. When GRID determines certain amount of generation from a unit, it does not make the decision based on whether or how much the unit has been derated. That is, for basis that no purchases are modeled at the Nevada-Oregon Border ("NOB"), the point from which the agreement provides wheeling. The two adjustments proposed by PIIC would result in a $4.8 million decrease to system NPC.

Q. Please provide some background on the DC Intertie contract.

A. The DC Intertie contract was executed 16 years ago on May 26, 1994, to provide deliveries of 200 megawatts of power from Southern California Edison at NOB under Amendment 1 to the Winter Power Sales Agreement ("WPSA"). The WPSA was executed on December 14, 1993 and provided up to 422 MW of power to be delivered to the Company's west control area. At the time the WPSA was executed, the Company had sufficient transmission rights to import 222 megawatts of power into the west control area. The agreement provided that if the Company procured additional transmission rights by June 1, 1993, then it could import the remaining 200 megawatts to its system. The Company secured the remaining 200 megawatts of transmission rights by acquiring 200 megawatts of transmission capacity on the DC intertie. The Company terminated the WPSA effective January 1, 2002, but kept its 200 megawatts of DC Intertie import rights.

Q. How does the DC Intertie contract benefit the Company's customers today?

A. The agreement takes advantage of the load diversity between summer-peaking California and the winter-peaking Pacific Northwest. The contract provides a valuable means of securing capacity and energy from California entities to meet retail loads. Loads in California are relatively low in the winter when loads in the

Company's west control area and the rest of the Pacific Northwest are at their highest.

Existing Long Term Contracts (PIIC Adjustments 11 and 13 regarding DC Intertie Costs, and Idaho Power PTP Contract)

Q. Please explain PIIC's proposed adjustment to costs associated with the DC Intertie.

A. PIIC argues that costs associated with the DC Intertie and Network Transmission Agreement between BPA and the Company should be removed from NPC on the basis that no purchases are modeled at the NOB, the point from which the agreement provides wheeling. The two adjustments proposed by PIIC would result in a $4.8 million decrease to NPC.

Q. How should the Commission judge the prudence of this contract?

A. Prudence should always be judged based on the information that was known at the time the contract was executed. It would not be reasonable to judge a 16-year old contract based on information that is available today that was not available 16 years ago.

Q. But there are no transactions modeled at NOB in the test period in this proceeding. Why is it appropriate to include costs related to the DC Intertie agreement in this proceeding?

A. In making their proposal, PIIC focuses on energy deliveries under the contract rather than the capacity and diversity benefits of the contract. It would be inappropriate to penalize the Company for prudently acquiring transmission rights 16 years ago by disallowing costs today based on hindsight and only looking at the energy value of a resource that can facilitate the delivery of both capacity and energy. By purchasing these transmission rights, the Company has purchased assurance that it can reliability serve its load obligations. PIIC's proposals based on the limited energy-only view of this contract is similar to arguing that the Company should only be able to recover insurance premiums when it receives proceeds under an insurance policy. The costs associated with this contract are modest in light of the benefit to the Company's overall transmission strategy and hedge against changes in the market.

Q. What does PIIC propose to adjust for the expenses of the contract between the Company and the Idaho Power Company ("IPC")?

A. PIIC claims that the contract that the Company has with IPC would no longer be needed after the Populus to Terminal section of transmission line goes into service. As a result, the expenses related to the contract should be removed, which would reduce the Company's system NPC by $0.8 million.

Q. Why does the Company disagree with this adjustment?

A. The notion that an existing contract should be terminated simply because a new resource may replace the function of that contract is unfounded. The referenced contract is a two-year contract that the Company entered into in 2009 to serve retail load, given the information at the time about the resources available to the Company to meet its obligation in the next two years. This contract is not the same as the short term firm contracts that the Company enters into from time to time and for a short duration, such as the ones listed as a correction earlier in my testimony. The capability of those short term firm transmission is modeled in

GRID at the assumed level based on what the Company has experienced historically, and the assumption should be modified when the Populus to Terminal line can provide the needed transmission capacity. The Company entered into that particular contract based on expected in-service date of the Populus to Terminal line and with the option of annual contracts only. As the result, the terms of the contract could not perfectly match the in-service date of the new transmission line, and the Company should not be required to time the contract terms precisely with resources that become available subsequently. Had the Company entered into a shorter contract, there would have been a potential gap prior to the new transmission line being in service to the detriment of customers. I recommend the Commission reject PIIC's adjustment.

Reserve Shutdown (Monsanto Adjustment 5)

Q. Please describe Monsanto's adjustment for reserve shutdowns.

A. Monsanto claims that the Company's forced outage rates and the rates used in GRID are calculated inconsistently and proposes that reserve shutdown hours should be added to the denominator of the forced outage rate calculations. The proposed adjustment would reduce the Company's system NPC about $0.8 million.

Q. Do you agree with this adjustment?

A. No. This adjustment has the effect of artificially lowering the forced outage rates by stating that the units would be available 100 percent of the time if they were to be called upon to run during the hours when they were on reserve shutdown for economic reasons.

Q. Please explain.

A. Contrary to what Monsanto claims, the Company's calculation of forced outage rates is consistent with how GRID applies them. Monsanto agrees that the planned outage hours should be excluded from the denominator in the calculation of forced outages. Removing the reserve shutdown hours are based on the same fact that no forced outage events are collected during either the planned outage hours or the reserve shutdown hours. Monsanto's proposal is the same as stating that if the units were to run during the hours when they were shutdown for economic reason, the units would not encounter any forced outage events. The proposal is not supported by logical or analytical reasoning. In addition, given the fact that GRID models reserve shutdowns, the rates are only applied to the hours when they are scheduled to run, which is a fact even supported by Mr. Widmer in his testimony stating that "[t]he Company's daily screen modeling in GRID specifically identifies when CCCTs are available but are not economic to run and essentially placed them on reserve shutdown so they cannot run." I recommend the Commission reject Monsanto's proposal.

Cal ISO (Monsanto Adjustment 7)

Q. Please describe Monsanto's adjustment to the Cal ISO Fees.

A. Monsanto recommends removal of the Cal ISO fees that are based on 2009 actual costs incurred by the Company, and replace them with a lower amount. Monsanto's recommendation is based on the assumption that a significant portion of the fees are not matched by electricity transactions that the Company included in the case and could incur the fees. This adjustment results in a $4.0 million decrease to the Company's system NPC.

Q. How do you respond to this adjustment?

A. I urge the Commission to reject this adjustment. Cal ISO fees are incurred for transactions at market points of SP15, NP15, and when the Cal ISO is the counterparty.[4] The bulk of these transactions are short term transactions made close to the time of delivery. Cal ISO is a major counterparty in the Company's activities to balance its system, which is a fact that Monsanto doesn't dispute according to Mr. Widmer's testimony stating "[h]istorical records reveal that most of the transactions with the Cal ISO as a counter party are incurred shortly before or on the actual day of delivery." Such activities are reflected in GRID as part of the system balancing sales and purchases, which are transactions computed by GRID representing the types of transactions that would be consummated shortly before or on the actual day of delivery. The Company continues to do business with the Cal ISO and continues to incur Cal ISO fees. There is no reason to arbitrarily eliminate expenses that are required to be incurred when doing business with the Cal ISO simply because the data in the Company's filing does not explicitly include those applicable transactions.

Q. Would removing the Cal ISO as a counterparty affect the operations of the Company's power system?

A. Yes. The Company enters into transactions with the Cal ISO in order to

[4] Mr. Widmer quoted an excerpt presumably from the testimony by Company's witness Mr. Duvall from the Wyoming Docket No. 20000-352-ER-09. Mr. Duvall's testimony in that case did not contain the quoted excerpt. However, Mr. Duvall did testify to content similar to the excerpt as the Second Supplemental testimony in the Company's Utah general rate case Docket No. 08-035-38, where the discussion was about the reason why the Company entered into transactions that had delivery points in SP15 when it did not have firm transmission rights.

economically balance the system. In doing so, the Company incurs Cal ISO fees. Not allowing the Cal ISO fees is the same as making the assumption that the Company would not do business with the Cal ISO. Removing Cal ISO as counterparty would limit the options that the Company may use to balance its system economically. As a result, NPC would go up due to those limitations and constraints.

Q. Does the Company expect that it will continue to do business with the Cal ISO in 2010?

A. Yes. The Company expects to do business with the Cal ISO in 2010 and the future and incur various fees in the markets governed by the Cal ISO. Costs such as wheeling costs are typically quantified for ratemaking purposes by using the most recent historic data, absent any known and measurable changes. This is exactly how the Company has normalized Cal ISO costs in this proceeding.

Q. Do you see other problems in Monsanto's proposal?

A. Yes. Despite the fact that the Company requested Monsanto to provide all workpapers supporting their adjustments, the workpapers for this adjustment is among the ones that do not support the amount of the adjustments. Given the magnitude of the adjustment, it seems that Monsanto proposes to remove the entire amount of the Cal ISO fees that the Company included in the case, replacing it with only a fraction of the actual Cal ISO fees that the Company has incurred during the period that is claimed to match the actual short term firm transactions that the Company included in the case. However, through September 2010, the Company has incurred approximately $3.2 million of Cal ISO fees, both wheeling fees and service fees, which are only $66,265, lower than what the Company included in the filing for the corresponding period. Accordingly, the Commission should reject Monsanto's argument that the Company would not incur Cal ISO fees in the test period, as well as rejecting the proposed adjustment, which would replace what the Company has included in the case with a fraction of the actual fees.

Cholla 4 Capacity (Monsanto Adjustment 10)

Q. What was the issue regarding the capacity of Cholla unit 4?

A. As the result of a major overhaul in 2008 the capacity at Cholla Unit 4 was upgraded. However, due to transmission constraints, the generation from the Cholla unit 4 to the Company's system has remained at the previous level. Monsanto argues that the upgrade should be reflected in GRID. The adjustment would reduce the Company's system NPC by $1.1 million.

Q. Do you agree with Monsanto's argument?

A. No. First, the argument ignores the physical transmission constraints on delivery of power from Cholla. Second, Monsanto has increased transmission capacity to accommodate the increased generation from Cholla unit 4 without increasing any other costs related to that capacity. Third, the purpose of derating the units for forced outages is to capture the lost generation due to such outages, while Monsanto's proposal would suggest the lost generation due to outages could be supplemented by the possible generation from the unit that cannot be delivered to the system.

Morgan Stanly Call Premiums (Monsanto Adjustment 11)

Q. **Please explain the Monsanto's proposed adjustment.**

A. Monsanto proposes to remove the capacity payments related to two of the Company's call option contracts because those contracts are not dispatched during the test period. The adjustment would reduce the Company's system NPC by $3.1 million.

Q. **Do you agree with Monsanto's proposed adjustment?**

A. No. Monsanto is seeking to disallow the capacity payments that the Company pays on call option contracts without demonstrating the imprudence of these costs. The Company executed these call option contracts to meet demand and ensure reliable service by providing physical delivery of energy during periods of increased demand and/or transmission constraints when prices are higher. So even if the contracts are not dispatched in GRID, they can provide customers a real benefit in the event of a change in the Company's system.

Q. **What would you recommend the Commission do in the current case?**

A. The Commission should reject Monsanto's proposal to remove the capacity payment of the call option contracts. As stated above, the contracts were entered into to meet demand and ensure reliable service by providing physical delivery of energy during periods of increased demand and/or transmission constraints when prices are higher. Monsanto's adjustment is similar to requesting a refund of your auto insurance payment every year when you have not been involved in an accident.

Other Proposals

Combined Cycle O&M Adjustment (PIIC Adjustment 14)

Q. Please explain PIIC's adjustment to O&M costs of combined cycle plants.

A. PIIC states that the proposed daily screening adjustment reduces the O&M costs associated with combined cycle plants.

Q. What is the basis for PIIC's adjustment?

A. Based on Mr. Falkenberg's testimony on this issue in prior cases and the reference to Mr. McDougal's exhibit, PIIC seems to be referring to the O&M that the Company might have added to fixed O&M for each start-up of a combined cycle plant.

Q. Is PIIC's adjustment reasonable?

A. No. The Company has not included any incremental O&M to reflect the additional costs of combined cycle plant start-ups. Therefore, there are no costs to remove.

Q. Do both Staff and Monsanto oppose updates to the Company's filed NPC?

A. Yes. The Company believes that updated information would provide the Commission with the most recent and more accurate information for the test period. While opposing updates to the Company's NPC, Monsanto proposes to selectively update components of the NPC, such as the recommendation to replace the Cal ISO fees that the Company included in the filing with actual Cal ISO fees that the Company has incurred for period prior to May 4, 2010. If the Company were to update the NPC to reflect all actual information that is available for the test period through September, the NPC for the twelve-month period ending December 2010 would be approximately $53.7 million higher than what was contained in the Company's original filing. If the Company were to update all NPC for actual information through May 4, 2010, as Monsanto recommended for the Cal ISO fees, the test period NPC would be $25.0 million higher than filed.

Q. Has the Company updated its NPC in this rebuttal?

A. No. However the Company believes updates improve the accuracy of NPC forecasts and reserves the right to propose updates in future filings Staff, PIIC and Monsanto proposed and the Company accepts adjustments to NPC, which total to an approximate $6.5 million reduction from what the Company originally filed.

Q. Please summarize your testimony.

A. In its direct filing, the Company proposed NPC of $1.07 billion on a total Company basis for the 12-month test period ending December 2010. In this current filing, the Company has revised its projected NPC to $1.063 billion on a total Company basis. The revised NPC incorporate corrections and positions that Staff, PIIC and Monsanto proposed and the Company accepts, which total to an approximate $6.5 million reduction from what the Company originally filed. For the adjustments that the Company does not agree with, I have provided explanations and evidence to support the Company's positions. I believe the revised NPC has reflected more accurate information and presented a reasonable compromise to positions proposed by Staff, PIIC and Monsanto.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Case No. PAC-E-10-07
Exhibit No. 71
Witness: Hui Shu

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Hui Shu

NPC Summary

November 2010

Idaho GRC 2010, Initial Filing		
	NPC ($) =	**1,069,701,315**
	$/MWh =	**$ 18.62**

Idaho GRC 2010, Rebuttal Filing

		Impact ($)	NPC ($)
Corrections, one-off			
1	Dunlap Reserve Contributor	121,389	1,069,822,704
2	Path C STF Transmission	(25874.30)	1,069,675,440
3	UAMPS Use of Facilities	(7000.00)	1,069,694,315
Adopted, one-off			
4	Commitment logic screens	(1684408.33)	1,068,016,906
5	Non-owned wind interhour	(1367358.97)	1,068,333,956
6	Colstrip planned outage moved to Spring	(215922.22)	1,069,485,393
7	Mona market	(438529.00)	1,069,262,786
8	APS Supplemental	(2640717.11)	1,067,060,598
9	Non-firm transmission	(1232943.93)	1,068,468,371
10	Top of the World Commercial Operation Date	1,904,544	1,071,605,859
	System balancing impact of all changes	(884,467)	
	Total Changes from initial filing =	(6,471,288)	
	Idaho GRC 2010, rebuttal filing		**1,063,230,027**

Case No. PAC-E-10-07
Exhibit No. 72
Witness: Hui Shu

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Hui Shu

Black Hills Power

November 2010

BLACK HILLS POWER, INC.
SD PUC DOCKET: EL-09-018

REQUEST DATE : November 5, 2009

RESPONSE DATE : December 8, 2009

REQUESTING PARTY: Black Hills Industrial Intervenors

BHII Request No. 1-68: Please explain the markets, in terms of liquid trading hubs, where the Company makes transactions. (e.g. Mid Columbia, 4 Corners, Palo Verde, etc.) Identify each hub where the Company trades, and the test year sales and purchase volumes, costs and revenues by hub or market.

Response to BHII Request No. 1-68:

Black Hills Power (BHP) trades at the following liquid trading hubs:

- Mid-Columbia (Mid-C)
- Four Corners 345
- Mona
- Midwest Independent System Operator (MISO)

These points of delivery are considered liquid trading hubs because there are established markets with published prices from various recognized sources.

See Attachment 68.1 for test year sales and purchase volumes, costs and revenues by hub or market.

Legend for Attachment:

- ✓ **HE** – the trading term for Hour Ending, 0100-0200 would be HE02 and so on
- ✓ **PHE** – the trading term for Price for Hour Ending
- ✓ **Transaction Type** – is the type of energy transaction that occurred, whether it is a purchase or a sale with a third party
- ✓ **Zone** – the trading point of receipt or point of delivery for energy, for example, the liquid trading hub
- ✓ **Market** – the transmission provider location code (PACW - PacifiCorp West, PACE - PacifiCorp East, AZPS – Arizona Public Service, PNM – Public Service of New Mexico, MISO – Midwest Independent System Operator)

BLACK HILLS POWER, INC.
SD PUC DOCKET: EL-09-018

REQUEST DATE : November 5, 2009

RESPONSE DATE : December 8, 2009

REQUESTING PARTY: Black Hills Industrial Intervenors

BHII Request No. 1-58: **Please explain why the Company's delivery pattern of power from the Colstrip contract appears to have a flatter profile than might be suggested by shaping the contract to optimize market revenue. Please explain any constraints that the Company encounters that limits its ability to maximize the contract revenue. Demonstrate that the methodology used is prudent.**

Response to BHII Request 1-58: First and foremost, the lowest cost resources available to BHP are allowed to serve BHP's Customers. Black Hills Power (BHP), on a monthly basis, maximizes the use of the Colstrip contract, based upon contractual parameters. The contract details are below:

Second Restated and Amended Power Sales Agreement between PacifiCorp and Black Hills Corporation *"Colstrip Contract"*	
Hourly Maximum Energy Delivery::	50 MW
Hourly Maximum Change:	±25 MW
Hourly Minimum Energy Delivery:	0 MW
Weekly Maximum Energy Delivery:	6,700 MWh
Monthly Maximum Energy Delivery based upon number of days in the individual month:	30-day Month 28,710 MWh 31-day Month 29,670 MWh

BHP will capture the maximum contract value by taking delivery of the contract energy to serve load or facilitate market sales. Typically this contract is utilized in the Day Ahead Energy Market where standard energy market products are traded in 25 MW blocks exercised in standard utility products – On-Peak hours equate to Monday through Saturday (0700-2300 MPT), Off-Peak hours equate to Monday through Saturday (0000-0700, 2300-2400) plus Sunday and Holidays (0000-2400). If maximum value is determined to be utilized for load, then the contract energy will be scheduled to BHP load, with a shaping pattern. BHP, as a practice, utilizes the maximum energy delivery on a monthly basis, if the market supports such.

Case No. PAC-E-10-07
Exhibit No. 73
Witness: Hui Shu

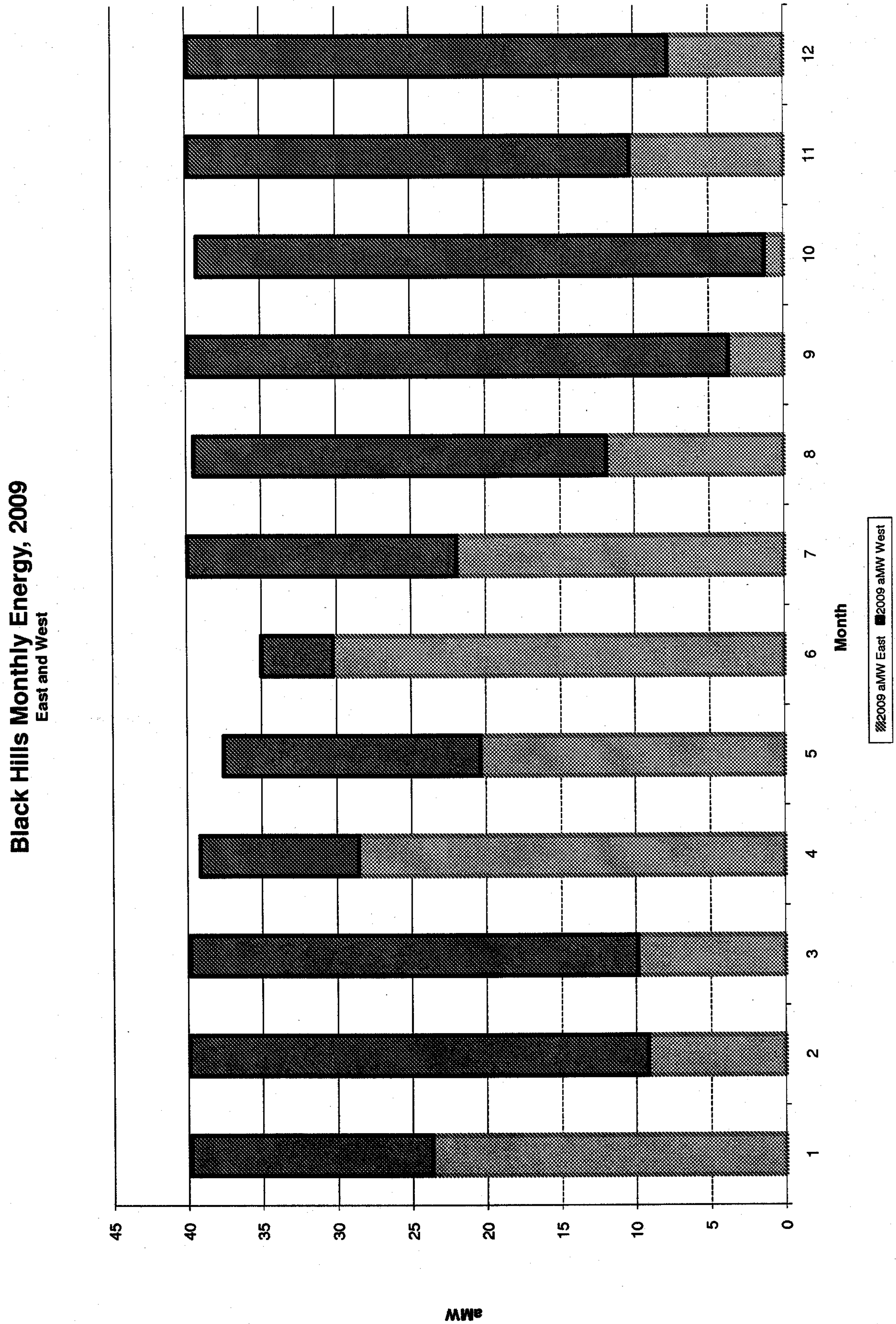
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Hui Shu

Black Hills Average Energy

November 2010


Black Hills Monthly Energy, 2009
East and West
aMW
45
40
35
30
25
20
15
10
5
0
1
2
3
4
5
6
7
8
9
10
11
12
Month
2009 aMW East
2009 aMW West

Case No. PAC-E-10-07
Exhibit No. 74
Witness: Hui Shu

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

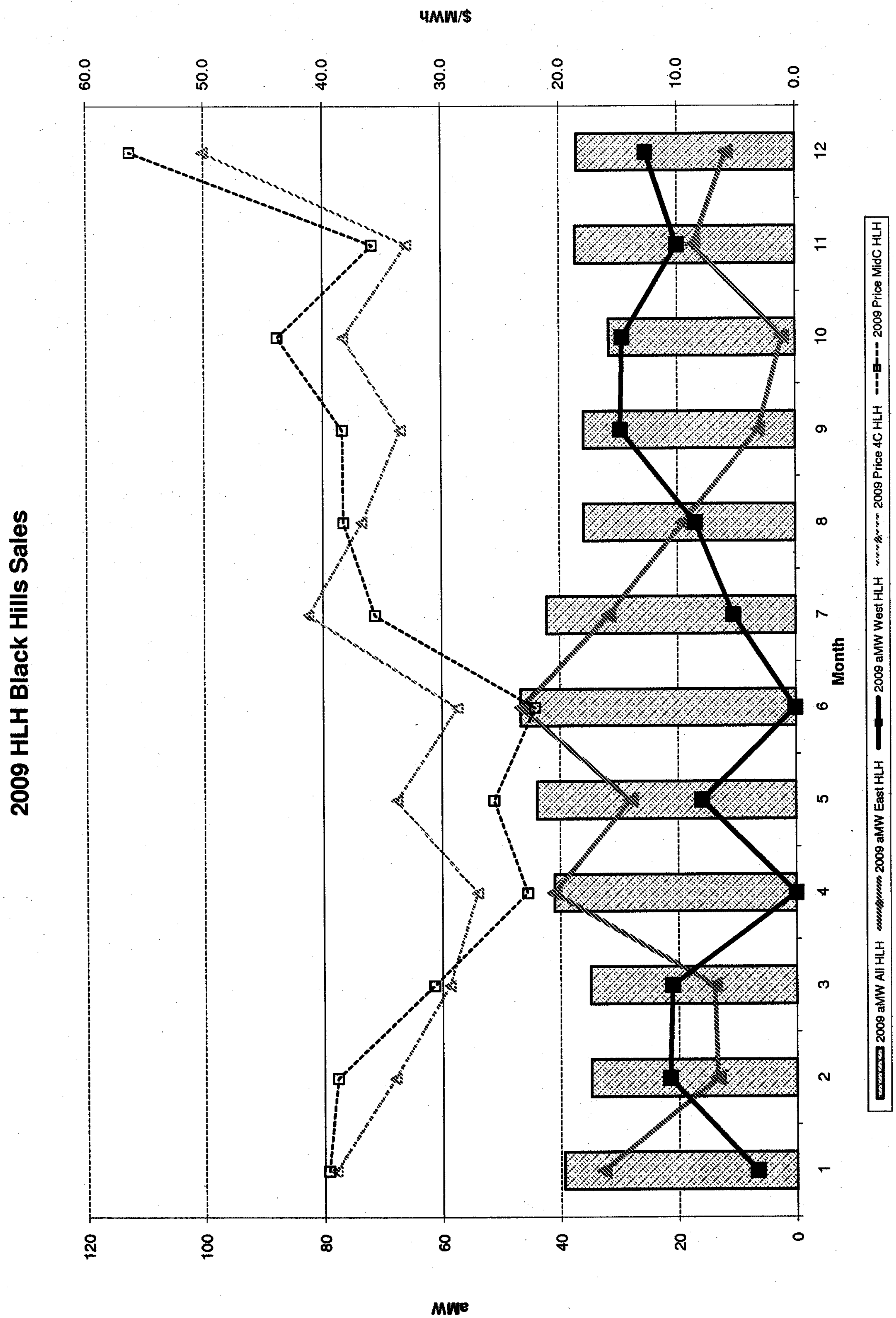
ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Hui Shu

Black Hills HLH

November 2010

Rocky Mountain Power
Exhibit No. 74 Page 1 of 1
Case No. PAC-E-10-07
Witness: Hui Shu



Case No. PAC-E-10-07
Exhibit No. 75
Witness: Hui Shu

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Hui Shu

Black Hills LLH

November 2010

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