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

A. My name is Gregory N. Duvall. My business address is 825 NE Multnomah, Suite 600, Portland, Oregon, 97232. My present position is Director, Long Range Planning and Net Power Costs.

Q. Have you previously filed testimony in this case?

A. Yes. I filed direct and two sets of supplemental direct testimony in this case.

Q. What is the purpose of your rebuttal testimony?

A. I respond to proposed adjustments on the Company's net power costs ("NPC") from the Division of Public Utilities ("Division"), presented in the testimonies of Mr. James B. Dalton and Dr. William A. Powell, the Committee of Consumer Services ("Committee"), presented in the testimony of Mr. Randall J. Falkenberg, and UAE and Wal-Mart Stores, Inc. (collectively "UAE"), presented in the testimony of Mr. Kevin C. Higgins. I will also comment on the proposal of Committee witness Ms. Cheryl Murray for access to the Company's GRID model contemporaneously with the rate case filing.

Q. Please explain how your testimony is organized.

A. First, I present the Company's recommendation for NPC in this case and explain why it is reasonable on an overall basis. Second, I outline various corrections and respond to the various proposals to update NPC. Third, I respond to the specific adjustments proposed by the Division, the Committee and UAE.

Q. Please provide an overview of your testimony.

A. As adjusted in my rebuttal testimony, the Company proposes an increase in total

Company NPC of approximately $34 million, or 1.6 percent, a much smaller increase than the Company sought in its 2007 general rate case. This increase is based upon an NPC study filed in compliance with the Commission's Order in the Docket 07-035-93 ("the 2007 rate case Order"). Additionally, to enhance reliability and decrease controversy, the Company volunteered modifications to its NPC modeling in hydro modeling and improvements in the Company's screening methodology for uneconomic generation. The Committee's testimony acknowledges that "the Company has made a number of adjustments and improvements to its GRID modeling and input assumptions." See CCS 4D Falkenberg at 2, lines 29-30.

The Commission's 2007 rate case Order, the Company's NPC study complying with that Order and the Company's additional, voluntary modeling concessions should have significantly reduced the number of adjustments in this case. Because the Company's filing was effectively a compliance filing implementing the Commission's 2007 rate case Order on commitment logic, planned outage schedule, modeling non-firm transmission and optimization of the SMUD contract, one would expect that this case would be free of further adjustments on these modeling issues.

Instead, the Committee has proposed 30 NPC adjustments, many of which address these and closely related issues. The Division has also proposed adjustments related to these issues, most notably, the planned outage schedule. In many cases, these adjustments involve aggressive assumptions, modeling inconsistencies and calculation errors. On the whole, the adjustments diverge from the goal of this aspect of the proceeding, which is to accurately determine and fairly normalize the Company's prudently acquired NPC. For example:

- While the Committee argued for the de-optimization of the SMUD contract in the 2007 rate case because of its unique circumstances, in this case, the Committee proposes to de-optimize four additional power sales contracts. Without explanation, the Committee proposes a different approach to "normalize" each contract and, in all cases, the approach is different from that used for the SMUD contract. The two largest adjustments proposed are for the Black Hills Power contract and the PSCo contract. When serious errors in the Committee's modeling are corrected, the analysis proves that GRID models these contracts correctly—indeed, even generously.
- In support of its planned outage adjustment of $4.1 million, the Committee asserts that its schedule is so "transparent and realistic" that there is no basis upon which to claim that the schedule is "'result oriented'"…"impractical, infeasible or otherwise improper." CCS 4D Falkenberg at 32, lines 799-802. However, on March 2, 2009, the Committee had to refile its planned outage schedule to correct errors and inconsistencies in its modeling assumptions, lowering the proposed adjustment by $1.2 million. My testimony shows that a change in one assumption—modeling around the historic outage start date instead of modeling around the center of the historic outage—would swing the Committee's adjustment from an NPC decrease to a $4.5 million NPC increase. Additionally, using the Committee's planned outage schedule from the 2007 rate case in this case would reduce the adjustment to less than

$220,000 total Company.

- Similarly, the Division filed a new planned outage schedule on February 26, 2009, correcting errors and lowering its proposed adjustment by $1 million. If the Division used the same planned outage schedule in this case that it proposed in the 2007 rate case, NPC would increase by $6.6 million.
- The Committee proposes to adjust the modeling of non-firm transmission from a four-year average to one year based upon a misrepresentation of the 2007 rate case Order. The Committee claims that the Commission "required the Company to model non-firm transmission in a manner consistent with its modeling of market caps," and "the Company uses one year of data to establish the market caps, but uses four years of data to establish the non-firm transmission." CCS 4D Falkenberg at 56, lines 1368-71. The Commission's 2007 rate case Order, however, expressly directed the Company to model non-firm transmission using "an average of the 48-month history as is done in the calculation of avoided costs." Order at 107.
- The Committee proposes that the Company add short-term firm transmission to its NPC study, an adjustment with which the Company agrees in concept but not in modeling. While indicating that the adjustment was based upon inputting the Company's actual short-term firm transmission, the Committee significantly inflated this data to increase the adjustment without ever explaining this fact or providing any rationale. On one path, for example, the Committee increased the amount of short-term firm transmission more than 30-fold.

- The Committee supports its adjustment imputing revenues for transmission imbalance services based upon the claim that GRID includes expenses for transmission imbalance services. This is flatly untrue. The Committee also bases this adjustment on a ten percent imbalance premium/discount, instead of the applicable five percent premium/discount. Finally, the Committee completely ignores the existence of a deadband for imbalance charges, within which most imbalance transactions are managed.
- On the commitment logic issue, the Committee acknowledges that the Company "has now adopted a more rigorous methodology for computing the screens." CCS 4D Falkenberg at 12, lines 348-49. Nevertheless, the Committee proposes a major adjustment using daily screens, misleadingly implying that the Commission approved daily screens for the Company's gas-fired units in the 2007 rate case Order. CCD 4D Falkenberg at 13, lines 365-366. In fact, the Committee proposed monthly screens for the Company's gas-fired units in the 2007 rate case, the Commission adopted these screens and the Company complied with and even enhanced this monthly screening approach in this filing. For call options, the Committee again misleadingly implies that the Commission adopted daily screens, when in fact the Committee proposed daily screens which the Commission rejected in favor of the monthly screens proposed by UAE and accepted by the Company.

Net Power Costs Recommendation/Reasonableness Check

Q. What is your NPC recommendation in this case?

A. Based upon corrections and accepted adjustments, my testimony now supports total company NPC of $1.048 billion, which is $418 million on a Utah allocated basis. This is the equivalent of $17.51 per MWh. The results of the Company's NPC study are provided in Exhibit RMP___(GND-1R).

Q. Have you reviewed the reasonableness of this recommendation on an overall basis?

A. Yes. The increase in NPC supported by this study is both reasonable and verifiable.

Q. As a part of your reasonableness check, have you compared the normalized NPC in this case to the Company's most recent actual power costs?

A. Yes. The Company's actual system NPC for calendar year 2008 were approximately $1.119 billion or 18.89/MWh. In the 2007 rate case, the Commission approved system NPC of approximately $1.014 billion or $17.31/MWh. The shortfall between NPC in rates and the Company's actual power costs for 2008 is approximately $104 million or $1.58/MWh on an annual basis. The shortfall between NPC requested in this rebuttal case and the Company's actual power costs for 2008 is approximately $71 million or $1.38/MWh.

Q. Is the 2008 shortfall between NPC in Utah rates and actual power costs a continuation of a multi-year trend?

A. Yes. 2008 is the eleventh consecutive year that the Company's actual power costs have exceeded its normalized power costs in rates in Utah. The Company has failed to earn its allowed rate of return in Utah during any year of this period.

Q. The Committee concludes that its proposed $1.021 billion for system NPC is very reasonable. Do you agree with their assessment?

A. No. First, the Committee's system NPC recommendation of $1.021 billion is somewhat misleading since it makes a $12 million adjustment to increase NPC by removing the wind generation of Rolling Hills which consists only of wind integration charges. This wind generation is mainly replaced with purchased power from the market. Not counting the impact of removing Rolling Hills, the Committee recommends disallowances of approximately $45 million and system NPC of $1.008 billion. Thus, the Committee proposes to decrease NPC from the amount now reflected in Utah rates.

Q. How does the Committee's position in this case compare to its position in the Company's 2007 rate case?

A. The Committee recommended $48 million in adjustments in its surrebuttal in the Company's 2007 rate case. While the Committee acknowledges that the "Company has made a number of adjustments and improvements to its GRID modeling and input assumptions," it nevertheless proposes adjustments almost identical in dollar magnitude to those proposed in the previous case. See CCS 4D Falkenberg at 2, lines 29-30.

Q. How does the Committee defend the reasonableness of its overall recommendation?

A. The only "reasonableness" factor cited by the Committee is the Company's 2009 budget for NPC, which is lower than its NPC recommendation. The relevance of budget forecasts for NPC is dubious, since such forecasts are not used to set NPC in rate cases, nor do they take into account normalizing adjustments. Indeed, the Committee admits the apples-to-oranges nature of the comparison on lines 1543-1550 in Mr. Falkenberg's testimony, acknowledging the differences between a power cost budget forecast and a regulatory filing.

The irrelevance of budgeted NPC is especially clear in this case, where the budget is based upon a load forecast that differs from the one used in this case. Under the load forecast used for the budget, loads in another state decreased, lowering NPC, but Utah's allocation factors increased, resulting in the assignment of costs to Utah at a level that approximately offset any decrease in NPC.

NPC Corrections

Q. Does the Company have corrections to its NPC study in this case?

A. Yes. The Company has five sets of corrections.

First, in MDR 1.8, the Company noted the following minor errors in the NPC study sponsored by my Second Supplemental Direct Testimony:

- 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;
- Chehalis screen: the duration of the screen should be at least eight hours.

The above corrections, except the Chehalis screen that will be corrected together with the updated screens, reduce system NPC by approximately $1 million on a net basis. These errors are the basis of the Division's Utah NPC adjustment of $419,253, which accepts all of the proposed corrections. These are also the basis of the Committee's adjustments CCS 14 (QF Modeling Errors), CCS 27 (Reserve Modeling Error) and CCS 29 (US Magnesium Reserves). These corrections sum to approximately $1.25 million (system), because the Committee accepts only the corrections that lower power costs and does not address corrections that go the other direction.

Second, the Committee proposes and the Company accepts CCS 13 (Grant Reasonable), remodeling this contract using the correct price. In making this correction, the Company has used the correct revenue stream from the contract of $10.57 million, which results in an increase of $264,053 in system NPC, not a decrease of $202,760 as proposed by the Committee.

Third, the Company has corrected the modeling of start-up costs within GRID to reflect the 2x1 nature of the Currant Creek and Lake Side plants. The input for MMBtus that are required to startup Currant Creek and Lake Side plants now reflect the actual operation of the plants, which have two combustion turbines and one steam turbine. Also, the input to GRID for Chehalis's additional operation and maintenance costs was approximated based on Currant Creek's costs in the Company's previous filing, and is corrected to match the current level of costs for the Chehalis plant in this rebuttal filing. This correction decreases system NPC by approximately $0.1 million.

Fourth, in updating the fuel costs for the Chehalis plant to the most recent forward price curve in the Company's second supplemental filing, the Company inadvertently omitted the costs of the Washington natural gas use tax. As shown in Exhibit RMP___(GND-2R), the costs of the natural gas use tax increases system NPC by approximately $3.8 million. This is computed by multiplying the Washington natural gas use tax of 3.852 percent by the total value of natural gas fuel used at the Chehalis plant in the test period. Both the existence of this tax and its $3.8 million impact were disclosed to all parties in June 2008 through discovery in the Utah Chehalis approval proceedings. For this reason, and because the gas use tax is an objective and verifiable pass-through expense, its inclusion in the Company's rebuttal filing should not be prejudicial. Exhibit RMP___(GND-3R) contains the June 2008 correspondence as well as the Washington Natural Gas Use Tax form which show the mechanics of how the tax is calculated.

Fifth, the parties have proposed adjustments to rate base to reflect the actual in-service dates of Rolling Hills and Glenrock III, January 17, 2009. Mr. McDougal has accepted these adjustments and adjusted the Company's rate base. Accordingly, we have revised NPC to incorporate the actual in-service date of these resources, increasing system NPC by approximately $1 million. The High Plains project was also incorrectly modeled using the capacity factor of Seven Mile Hill instead of its 35.7 percent capacity factor. The correction of this error increases system NPC by approximately $300,000.

NPC Updates

Q. In CCS 16, does the Committee propose an update for the Biomass non-generation agreement?

A. Yes, although the Committee claims that this is an adjustment, not an update. The Company did not model the contract for 2009 because it did not exist at the time of the December filing, nor was the Company sure that it would execute a new agreement given the potential impact of the economic downturn on the wood products industry in Oregon and the Biomass QF facility. As of the date of this filing, the situation has not changed. The Company has not executed a new Biomass agreement, or even begun negotiating a new agreement. In light of these facts, the Commission should reject this update. If the Commission accepts the update, it should be expressly contingent upon the Company actually executing an agreement similar to the previous years' agreements on or before the rate effective date in this case.

Q. Does the Company propose any updates to its NPC in rebuttal?

A. No, for three reasons. First, the Company's NPC were comprehensively updated just three months ago when the Company made its compliance filing with the Commission's test year decision. Second, the Commission rejected the Company's proposal to update its NPC for the forward price curve in the 2007 rate case. Third, the Company has concluded that the best way to ensure that NPC are reflected in rates in an accurate and up-to-date manner is through an energy cost adjustment mechanism ("ECAM"). Such a mechanism ensures that updates are made to reflect actual changes in all costs, not just a selected few, irrespective of whether those costs are rising or decreasing.

Q. Both the Division and UAE propose to update the Company's NPC to reflect the December 31, 2008 forward price curve, instead of the November 4, 2008 forward price curve used in this case. Does the Company oppose such an update?

A. Yes. In the 2007 rate case, the Commission rejected the Company's proposal to update the forward price curve in rebuttal, despite the Company's evidence that the forward price curve used in the case was approximately 8 months out of date and about 25 percent lower than the Company's then-most recent forward price curve. The Commission ruled that such an update required more review than was possible late in the case and the evidence that the Company was fully hedged mitigated the need for an update. These same reasons the Commission used to reject the Company's update in the 2007 rate case are applicable to the updates proposed by the Division and UAE in this case.

Q. Is there any principled way to distinguish in this case the 2007 rate case Order denying an update for the forward price curve?

A. No. Neither the Division nor UAE supported the Company's proposal to update the forward price curve in the 2007 rate case and the Committee actively opposed the proposal. In addition, no party proposed to use the then most recent official forward price curve (March 31, 2008) in its direct testimony in the 2007 case. The only difference between the previous case and this case is the direction of the change in the forward price curve change. Indeed, the argument for making an update in the 2007 rate case was more compelling because the forward price curve was much more out of date and out of step with the most recent official forward price curve.

Q. Does the Division also propose an update to the Company's coal costs?

A. Yes. The Company updated its diesel fuel inputs to coal costs as a part of its December 2008 filing. These costs were reduced significantly from the Company's previous filing, based upon the Company's new forecast for 2009 fuel costs. The Division proposes an adjustment of $7.8 million to reduce the costs of fuel for its purchased coal contacts based on even more recent prices.

Q. Does the Company oppose this update?

A. Yes. The Company is concerned about the selective nature of the adjustment, looking at a single cost component and updating it only when it goes in the direction of lowering costs. The Company is also concerned about the late-filed nature of this adjustment, especially given the fact that it is the single largest adjustment proposed by the Division.

Q. Please address your procedural concerns about this adjustment.

A. The Division presented this adjustment in Supplemental Direct Testimony filed on February 26, 2009, two weeks after the deadline for the Division's testimony.

Just before the February 12, 2009 deadline for its testimony, the Division sought February 2009 forecast fuel prices. Although Mr. Dalton's Supplemental Testimony suggests that he filed it late because he was waiting for a response to a data request from the Company, the Company's response to the data request was not due until after the February 12, 2009, filing deadline. The Division sought the information too late for it to be included in its direct testimony. As just discussed, in the 2007 rate case Order, the Commission made clear that it would not entertain a forecast update raised late in the case. Here, the testimony proposing a forecast update is particularly improper because it is based upon information acquired after the due date of the Division's testimony.

Q. If the Commission adopts the Division adjustment, do you have concerns that this would violate the overall balance of projecting costs for the rate effective period?

A. Yes. When projections are made, there is an expectation that some of the estimates will be lower than actual and some higher. However, overall the expectation is they will generate a reasonable outcome. Here, the case was filed based on cost validation and escalators for all costs based upon the most recent data available in November 2008. At this point, to selectively update certain cost elements which reduce costs without doing a comprehensive update, both increases in costs and decreases, will likely underestimate the total costs expected to occur in the rate effective period.

Q. Please provide an example of this selective approach to making adjustments related to the Division proposed adjustment to coal costs.

A. At page 6, lines 81-89 of Mr. Dalton's Supplemental Direct Testimony, he discusses his approach of calculating the revised coal cost impacts and the related results of the various plant units. The results demonstrated that all plants except Huntington had a lower cost, but the update would actually increase Huntington's cost level in the case. While the Division's adjustment reflects cost decreases in most of the plants, it does not reflect an offsetting cost increase for Huntington. While this is a relatively small cost item, it does illustrate the fundamental unfairness of this adjustment.

Q. How did the Company's projected fuel costs for coal from the last general rate case compare to actual costs in 2008?

A. I have prepared an Exhibit RMP___(GND-4R) which compares the crude oil projections used in the 2007 rate case with the actual crude oil costs which were incurred to serve customers. As can be observed in the exhibit, in May 2008 when the Company filed its rebuttal testimony in the 2007 rate case, the Company's forecast was $79/barrel, while actual crude oil costs were $125/barrel, a difference of $46/barrel.

Q. Did any party propose to update fuel costs for coal in the previous rate case to address the fact that the Company's projected costs were so far below market?

A. No. Given the Commission's rejection of the Company's proposed update to NPC for the forward price curve, it seems clear that the Commission would have rejected such a proposal.

Q. Was the Company's projected price for fuel costs for coal well below actual prices for most of 2008?

A. Yes. For the first 10 months of 2008, the Company's projection was well below actual market levels. In November and December 2008, the market dipped. This end-of-year market decline was reflected in the Company's updated fuel price in the December 2008 filing. Between the Company's July 2008 and December 2008 filings, the projected price of crude oil utilized in this case, declined from $140/barrel to $68/barrel, a level that is below the amount currently in rates.

Q. Would an ECAM capture the impact of volatility in the forward price curve and fuel costs for coal in a reciprocal and even-handed manner?

A. Yes. If the Commission is concerned about reflecting the most recent forward price curve and fuel costs for coal in the Company's NPC, it should not accept the forward price curve adjustment proposed by the Division and UAE, or the adjustment to coal costs proposed by the Division in this case, but instead require these parties to work with the Company to develop an ECAM.

Responses to Specific Adjustments

Optimization (CCS 9-12)

Q. Please describe the contract adjustments proposed by the Committee for the Black Hills, Public Service Company of Colorado ("PSCo"), Sierra Pacific, and Utah Municipal Power Authority ("UMPA") II power sales contracts.

A. Based upon the Commission's 2007 rate case Order directing the de-optimization of the modeling of the SMUD contract, the Committee proposes to de-optimize another four long-term sales contracts. This is true even though the Committee argued for the de-optimization of the SMUD contract in the 2007 rate case in part on the basis that the "Commission has already recognized that the history of the SMUD contract differs from that of other contracts." CCS-4SR Falkenberg at 45, lines 1144-45.

Q. How does the Committee propose to model these contracts?

A. The Committee uses historic data to shape these four contracts in GRID. Each contract uses a different method, which are all different than the method used for shaping the SMUD contract the Committee recommended in the last case.

Q. Please describe the five different methods used by the Committee to normalize these four power sales contracts and the SMUD contract.

A. First, for the Black Hills contract, the Committee used the average of four years of annual energy to create a sale that was flat in all hours of the year.

Second, for the PSCo contract, the Committee used 2007 annual average energy to create the minimum take for the contract and then ran it through the normal GRID logic for shaping contracts. This resulted in a virtually flat sale across all hours of the year.

Third, for the Sierra Pacific contract, the Committee used two months in 2007 to calculate monthly average energy and use it as the minimum take for the contract in the remainder two months of the contract terms and then ran it through the normal GRID logic for shaping contracts. This too resulted in a virtually flat contract.

Fourth, for UMPA II, the Committee used 2007 data and created 24 hourly numbers by averaging each hour across the year. The minimum of the 24 averages was then input into the GRID model as the minimum take value.

Fifth, for the SMUD contract, the Committee used four year monthly average energy to develop the shape of the contract.

There is little logic in these methodologies let alone consistent logic. All other contracts are allowed to be shaped by GRID pursuant to the terms of each individual contract.

Q. Are the shapes developed by the Committee reasonable?

A. No.

Q. Please explain.

A. As an example, in "normalizing" the Black Hills contract, the Committee did not consider that Black Hills can take delivery under their contract in multiple delivery points on either the east or the west side of the Company's system. As shown in Exhibit RMP___(GND-5R), in 2007 the total Black Hills sales were flat across the 12-month period. However, Exhibits RMP___(GND-6R) and RMP___(GND-7R) put the energy take and the market prices by east and west in the same graphs, and clearly show that Black Hills used the flexibility built in the contract to increase the value of the contract to them throughout the year and during both heavy load hours and light load hours, which in turn increases the cost to the Company. In fact after reviewing the data, the Company believes it has underestimated the costs of the Black Hills contract, which is demonstrated in Exhibit RMP___(GND-8R).

Another example is the PSCo contract. The Committee failed to account for all of the energy under the contract in its analysis which occurs across multiple delivery points. When all of the energy is considered, the contract is not flat; rather it is shaped similar to the shaping produced by GRID. Exhibit RMP___(GND-9R) compares the average hourly dispatch in 2007, what is modeled by the Company, and what is modeled by the Committee. This exhibit clearly shows that the Committee's modeling of the PSCo contract is in no way close to reality.

Q. Did you revisit the shaping of the SMUD contract?

A. Yes. Given the serious flaws in the methodologies used for the four contracts described above, the Company took a closer look at the SMUD "normalization." It turns out that the original method only looked at the firm power portion of the SMUD contract. However, the contract also allows SMUD to take provisional power. When both of these are taken together, the SMUD contract showed that the shape proposed by the Committee in the last general rate does not comport well with the historic take by SMUD under the contract. Exhibit RMP___(GND-10R) shows the monthly pattern of the total firm and provisional sales in a 4-year period, and Exhibit RMP___(GND-11R) shows the comparison of the 2007 shape and the "normalized" shape. Because the Committee's approach does not simulate the actual history of the SMUD contract, and for the policy reasons previously outlined in my Second Supplemental Direct Testimony, the Commission should order a return to normal, optimized modeling for the SMUD contract.

Q. Do you have other concerns about "de-optimizing" the contracts?

A. Yes. Whether or not other parties actually optimize their take of energy at all times from the Company, the Company is exposed to the potential of such an optimization. This fact should be taken into account in how these contracts are modeled.

Q. Have you looked at "normalizing" any purchased power contracts using historic data?

A. Yes. As an example, Exhibit RMP___(GND-12R) compares the energy usage during heavy load hours for the capacity contract with the Bonneville Power Administration ("BPA"), both the 4-year average and 2007 monthly, against the optimized usage pattern generated by GRID and found that GRID significantly over-optimized the usage of the contract during the heavy load hour period. If the Company were to follow the same methodologies that the Committee has applied to the sales contract, NPC would increase because the over-optimized energy usage during heavy load hours would be moved to light load hours. Using a historic “normalization” process for the BPA capacity contract would raise NPC by about $8 million total Company during the test period.

Q. What is your recommendation on normalization?

A. Given the evidence presented in my exhibits, the Commission should reject the Committee’s proposed adjustments to the Black Hills, PSCo, Sierra Pacific and UMPA II power sales contracts. In addition, in light of the new evidence presented on the normalization of the SMUD contract, I recommend that the Commission revert to using GRID to normalize the energy under the SMUD contract.

These four adjustments and the ”normalized” SMUD using the history of only a portion of the contract should be rejected based upon the use of inconsistent methodologies and because the normalized values are not representative of actual historic usages under the contracts. Restoring the modeling of the SMUD contract to let the GRID dispatch the contract increases NPC by about $2 million. If the Commission uses historic normalization for any or all of these five power sales contracts, then the Company recommends that the Commission also use history to normalize the BPA Capacity contract. There is no principled reason to differentiate between the normalization of purchase and sales contracts.

Q. Are you introducing any new information in your analyses that is not available to the Committee?

A. No. The information that the Company used comes from the same data set that has been provided to the Committee.

SMUD Contract Pricing (CCS 15 and Division)

Q. Do the Committee and the Division both propose adjustments to the current $37/MWh price for the SMUD contract?

A. Yes. The Committee proposes to increase the imputed contract price to $46.9/MWh and the Division proposes to increase the imputed contract price to $41.56/MWh.

Q. Do you have concerns about the Committee's analysis?

A. Yes. To support the Committee's adjustment, Mr. Falkenberg selectively chose the higher numerical value from the two separate pieces of the total calculation. The Company presented data for the contract revenues and $94 million upfront payment year-by-year and on a levelized basis. In Exhibit RMP___(GND-3SS) that I sponsored in my Second Supplemental Direct Testimony, I selected the levelized numbers from both calculations to give the Commission an approximation of the impacts of a different approach while at the same time continuing to support the $37/MWh. However, the Committee's SMUD pricing adjustment uses the actual revenues from the contract and the levelized value of the $94 million upfront payment. This approach is inconsistent with regulatory matching principles.

Q. How does the Division's approach compare and do you support this approach?

A. Division witness Dr. Powell uses an approach very similar to the approach I used in Exhibit RMP___(GND-3SS). His adjustment is a levelized approach for both of the components and produces a similar number to the one I generated. The differences between the two calculations are in escalation and present value assumptions. Unlike the approach used by the Committee, the Division's proposal is consistent with regulatory matching principles.

Q. Is there another approach that the Commission should consider, one that is more consistent with the Commission's historical accounting practices?

A. Yes. If the Commission is going to adopt an entirely different approach to pricing this contract from the $37/MWh it previously ordered, it should use the same regulatory liability approach it used in handling the gain from the Centralia sale.

Q. Please describe the regulatory liability approach for handling money that is owed to customers.

A. The Commission adopted a regulatory liability approach when they approved the sale of the Centralia Power Plant and ordered the gain to be passed back to customers over the remaining life of the plant.

Q. How would this approach apply to the $94 million payment associated with the SMUD contract?

A. If the Commission is going to change its approach to the contract and look to separately account for the return of the $94 million to customers, it should calculate this by assuming that the creation of a regulatory liability for the $94 million payment in 1987, with the amortization of the liability over the life of the SMUD contract. This would be similar to the Commission's treatment of gain realized on the sale of the Centralia Plant in 2000. On page 21B of the Order in Docket No. 99-2035-03, the Commission stated: "Because ratepayers bear the risk of purchasing replacement power over the remaining life of the Centralia plant after it is sold, we conclude that amortizing the gain over the remaining life of the plant best implements the matching principle we employ in ratemaking. We further conclude that the gain ….. should be separately recorded on a system basis in the year the transaction closes." Ordering paragraph 6 states: "The gain is to be amortized as an offset to ratebase not associated with any previous acquisition adjustment."

Q. How did the Company account for the regulatory liability associated with the Centralia gain?

A. For ratemaking and FERC accounting purposes, the Company recorded the Centralia gain to FERC Account 254, Regulatory Liabilities. The gain was amortized in FERC Account 456, Other Electric Revenues. Similar accounting could be adopted for the SMUD prepayment.

Q. If the Commission decides to adopt this approach how would they develop the imputation value for the $94 million payment made in 1987?

A. I would recommend letting the annual revenues continue per the contract for each of the remaining years through 2014. This would leave the remaining value of the amortization of the regulatory liability as the revenue imputation adjustment. The approach would establish a rate base liability for the $94 million in the year received (1987) and amortization of the benefit back to customers over the contract life (2014). This approach is consistent with the Commission's view expressed at page 27 of the 2007 rate case Order "that the SMUD contract revenue imputation should be based on information that was known at the time of contract execution."

Q. **Please describe the level of imputation for the remaining years of the contract.**

A. I have prepared an Exhibit RMP___(GND-13R) which shows the year-by-year value of the amortization and return on the unamortized balance of the $94 million payment. These two components are translated into a revenue requirement value based on the last Commission ordered capital structure and divided by the contractual MWh in developing the $/MWh revenue imputation level. This approach is simple to understand, follows Commission precedent for amortization of a balance back to customers and establishes the level of imputation to be included in rate cases over the remaining life of the contract. For 2009, the contract generates revenues of $21.99/ MWh and the imputation of the $94 million is ($15.73/ MWh) or a total $37.72/ MWh.

Q. Are you recommending that the Commission adopt this approach for pricing the SMUD contract?

A. No. I continue to believe that my recommendation of $37/MWh for the SMUD contract from the Second Supplemental Direct Testimony is reasonable and consistent with the orders in the Company's 1999 and 2001 general rate cases. However, this analysis provides the Commission with an alternative approach to setting an imputation level if it decides to value the $94 million payment had a regulatory liability been set up at the time of the $94 million payment. The imputation value of this approach for 2009 is essentially the same as the $37/MWh I have presented in this case and reinforces the reasonableness of that number.

Planned Outage Schedule

Q. Have the Division and the Committee proposed adjustments to the Company's planned maintenance schedule and then proposed corrections to these adjustments?

A. Yes. The Committee proposed an adjustment of $4.1 million based on an alternative maintenance schedule in its direct testimony. In an updated workpaper served on the Company on March 2, 2009, the Committee reduced this adjustment to about $2.9 million based upon errors in its original schedule. The Division originally proposed an adjustment of $2.4 million based on yet another proposed maintenance schedule. The Division's Supplemental Direct Testimony reduced this adjustment to $1.9 million based upon errors in its original schedule.

Q. The Committee and Division use a 4-year historical approach to calculating a future schedule for plant outages. What concerns do you have with this approach to modeling planned outages?

A. Most fundamentally, it is impossible to model four years of actual outage data within only one year. In order to compress four years of data into a single year, assumptions and changes need to be made to historic data. It is mistakes and inconsistencies in those assumptions that caused both the Committee and Division to refile their alternative schedules and reduce their proposed adjustments. The approaches proposed by the Committee and the Division result in alternative planned outage schedules that are ultimately more subjective and less reasonable than the Company's approach which uses history as the primary guide to the schedule, but also takes into account factors that make the schedule logical, realistic and consistent.

Q. Can you briefly describe the approach used by the Committee?

A. Yes. The Committee's general approach to modeling planned outages is to take each outage in a four year historic period and divide that outage by four to come up with an annual level for the test period. According to the Committee, these shorter individual outages are selectively "centered" around the actual outage date for purposes of placing them at some point in time in the test period. While the Committee's testimony states that it "centered" the longer outages for purposes of determining their timing in the schedule, the Committee began the outage in the center of the actual outage in its original and corrected schedules rather than centering the outage at the actual mid-point of the historic outage. Indeed, if the Committee "centered" the test period outage around the actual mid-point of the historic outage for its schedule, it would reduce the Committee's adjustment to a de minimis decrease in NPC. See Exhibit RMP___(GND-14R).

Q. Is the Committee's approach subjective and can the results vary depending on the start date of the planned outage?

A. Yes. The Committee extols its schedule as so "transparent and realistic" that there is no basis upon which to claim that the schedule is "result oriented…impractical, infeasible or otherwise improper." CCS 4D Falkenberg at 32, lines 799-802. But while the Committee seems to have chosen some version of the mid-point of the actual maintenance schedule as the start date for planned outages, they could have selected many different points within that range of the duration of the actual historic outage and come up with substantially different results. I have prepared Exhibit RMP___(GND-14R) which demonstrates the various results for beginning and mid-point start dates, centering, and end of period finish date for the outage.

Q. Please explain the results of the exhibit and impacts on NPC for the outcomes.

A. If the start date of the Committee's outage modeling was positioned at the beginning of the actual outage time period (instead of somewhere around the mid-point), the resulting schedule would produce an increase in NPC of $4.5 million. And, as demonstrated by the Committee's need to file a corrected schedule, using the start date of the actual historic outage is certainly a more reliable modeling point than some undefined mid-point. With this small and legitimate change in assumptions, the Committee's adjustment swings from a reduction in NPC to a large increase in NPC.

Q. What is your view on the simplification and straightforwardness of this approach to modeling outages?

A. As the Committee notes, there is no debate in the length of the outages used by the parties. The entire debate is when to start each of the outages. The Committee's approach is anything but straightforward. I have established how one simple assumption change results in an entirely different outcome. The Committee's approach will not produce year-on-year stability. Additionally, since their direct testimonies, both the Division and the Committee have modified their adjustments on planned maintenance. This is crystal clear evidence that, in fact, these approaches are not simple and straightforward since the authors of the approaches are still modifying the results at this late stage of the process. Even on the "un-debated" length of the maintenance outages there are uncertainties: it is unclear how the Committee makes sure the total length of the maintenance is correct because the methodology that the Committee used pieces together the individual maintenance outages, after dividing by four, and joins the ones from different years in a single year which may also be plagued by overlapping schedules for an individual unit.

Q. The Committee and the Division both proposed outage schedules in the last case. If the Commission were to use those schedules with this year's length of the outages, what impact would they have on this case?

A. Referring back to Exhibit RMP___(GND-14R), I have modeled the outages schedules of both the Committee and Division from the last case with the outage durations from this filing. In the case of the Division, the result would be an increase in NPC of $6.6 million over the level filed by the Company. The Committee's schedule would lead to a decrease in NPC of less than $1 million, a substantial decrease from the level of the adjustment they are proposing in this proceeding. Once again, rather than accepting the Company's compliance with the 2007 rate case Order as sufficient, the parties have proposed adjustments to their own outage schedules from the 2007 rate case that are much more punitive to the Company than those they previously presented.

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

A. As I previously stated, the parties are all using the same number of days for the planned outages. The Company uses a tree-modeling approach which systemically spreads the planned units for maintenance over defined periods of time. Using history as a guide, the Company understands that spring and fall timeframes are the cheapest periods of time to have plants down. As can be seen in Exhibit RMP___(GND-15R), most of the units are scheduled in the spring. For normalized rate making purposes, planned outages are scheduled so that all units are on maintenance during the test year, and the timing of the outages are scheduled not to fall within certain periods during the year due to the obligations to serve both the retail load and wholesale contracts. For example, the schedule takes into consideration the need to avoid planned outages in the winter.

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

Q. Do you assume the same fixed maintenance schedule in all normalized NPC calculations?

A. No. The schedule of each unit may move a little depending on the length of the normalized planned outages that precedes it. However, the structure of the tree will remain the same from one proceeding to another.

Q. What do you conclude from your analysis of the various proposals presented by the parties?

A. The planned outage schedules presented by the Committee and the Division are both supposedly based upon modeling actual planned outage schedules over the past four years. However, as can be seen from the differences in the two "actual historical" schedules presented in this case, and by comparing these to two different "actual historical" schedules in the last case, there is no one true way to compress four years of data into one year and call it an "actual historical" schedule. Both parties made modifications to their maintenance schedule, and both resulted in significant changes in their adjustments. This clearly shows that their schedules are not straightforward and objective. In addition, neither the Committee nor the Division have demonstrated that the Company's schedule is unreasonable and neither have shown that their schedules are superior to either the Company's proposed outage schedule or the outage schedules presented by the Committee and Division in the 2007 rate case.

The Company's schedule is stable and predictable while those of the Division and Committee are arbitrary and have no consistent logic from year to year. The schedule put together by the Committee would also cause the units to be on and off maintenance multiple times during the test period. The Commission should therefore accept the Company's planned outage schedule and methodology in this case.

Transmission Adjustments

Non-firm Transmission

Q. Does the Committee agree that the Company implemented the Commission's order on including non-firm transmission in the GRID model?

A. Yes. See CCS 4D Falkenberg, page 55, lines 1344-1345.

Q. In CCS 22, does the Committee nevertheless propose a change to the manner in which the Company has modeled non-firm transmission?

A. Yes. The Committee acknowledges that it recommended in the 2007 case that the Company model non-firm transmission using 48 months of data, this 48-month approach was consistent with avoided cost modeling, and the Commission adopted this approach in approving the Committee adjustment. Nevertheless, the Committee proposes in this case to use 12 months of data to model non-firm transmission. This proposal increases NPC by approximately $1 million.

Q. Does the Company agree that this is the correct approach to modeling non-firm transmission in NPC?

A. No. Traditionally, the Company has modeled only long-term, firm transmission as a part of its normalized NPC. This was due both to the difficulty of accurately predicting and modeling short-term or contingent transmission and the fact that modeling such transmission as fully available was contrary to normalization principles. In the avoided cost order in which the Commission first ordered the modeling of non-firm transmission, the order notes the reservations of the Committee about modeling non-firm transmission: "The Committee has no objection to modeling non-firm transmission if it is legitimate but notes that it has no evidence of a reasonable amount that is routinely available." *In re PacifiCorp*, Docket No. 03-023-14, 2005 WL 3710324 at 10 (Utah PSC October 31, 2005).

The Commission adopted use of a 48-month history for modeling non-firm transmission presumably to mitigate these concerns raised by the Committee about forecasting and normalizing a variable, contingent input. The Committee's proposal to input non-firm transmission takes a step back from ensuring that the modeling accounts only for "a reasonable amount that is routinely available." The proposal reduces the accuracy of an input that is already potentially unreliable.

Q. Does the fact that the Committee is already contesting the amount of non-firm transmission modeled in this case confirm the Company's concerns about using this data in modeling normalized power costs?

A. Yes. Because it is difficult to accurately forecast contingent transmission, the Company was concerned that this issue would immediately become controversial in subsequent cases.

Q. Is it poor policy to accept a Committee-proposed change to the Company's approach in this case when that approach was proposed by the Committee and adopted by the Commission in the last case?

A. Yes. The Company did not support the Commission's proposal to model non-firm transmission in the last case for the reasons just noted, but carefully implemented it in this case to comply with the 2007 rate case Order. Without even giving the Company a chance to implement the Committee's proposed approach to non-firm transmission in a single rate case cycle, and without giving the Commission an opportunity to observe and test the results of its Order, the Committee now makes a new proposal. The Commission should be skeptical of new Committee adjustments in this case to Committee adjustments approved in the last case because the Commission has not even had one full rate case for the Commission to observe the operation of the original adjustment. In addition, the Company should not be put in a position where NPC dollars are subject to adjustment on a particular issue, even though it is undisputed that the Company has complied faithfully with a just-issued Commission order on that issue.

This is an important policy issue for the Commission to resolve because the Committee has proposed adjustments in this case to virtually all of the material Committee adjustments the Commission adopted in the last case, including the modeling of non-firm transmission, planned outages and commitment logic screens. Indeed, if the Committee accepted its own Commission approved-adjustments from the last case, it would eliminate the bulk of the Committee's adjustments in this case.

Short-term Firm Transmission

Q. In CCS 23, does the Committee also propose to extend the Commission's order on including non-firm transmission in the GRID model to include short-term firm transmission in the GRID model?

A. Yes.

Q. Has the Company historically excluded short-term firm transmission from the GRID model?

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

Q. What short-term firm transmission has been included in the Company's December NPC study?

A. Short-term firm transmission is included between the Jim Bridger generating plant and Utah and between Four Corners and south path 15 ("SP-15").

Q. How has the Company forecast expenses for short-term firm transmission?

A. The Company forecasts short-term firm transmission expense, just like all other transmission expenses, using its most recent historical actual expense.

Q. Why doesn't the Company model transmission availability in GRID using the same approach?

A. Estimating transmission expense in rates and modeling transmission availability in an optimizing NPC model are very different exercises. For ratemaking purposes, the Company must estimate its actual transmission expense as accurately as possible, so it uses forecasts based upon its most recent actual expenses. For net power cost modeling, to smooth variations and optimize operations associated with as, if and when available transmission service, normalizing assumptions are employed that may differ from those used in capturing related expenses in rates. Historically, one such assumption the Company has used is that transmission availability is not modeled for normalized NPC unless the transmission is available on a firm, long-term basis.

Q. In light of the Commission's order requiring the modeling of non-firm transmission, what is the Company's response to including short-term firm transmission, regardless of its variability, in its GRID model?

A. The Company agrees that the modeling of non-firm transmission and the modeling of short-term transmission are closely related. For this reason, the Company is willing to adjust its filing in this case to model short-term firm transmission on the same basis as it models non-firm transmission.

Q. In CCS 23, the Committee proposes to reduce the Company's system NPC by approximately $9 million to reflect the modeling of short-term transmission. Is this a reasonable adjustment?

A. No, for at least two reasons.

First, the Committee proposes to model short-term firm transmission using one year of data, similar to its proposal on the modeling of non-firm transmission in this case (but contrary to its proposal on the modeling of non-firm transmission in the last case). There is no principled basis for using one year of data instead of 48 months of data because short-term firm transmission varies significantly from year-to-year, just like non-firm transmission.

Second, the Committee has significantly overstated the amount of short-term firm transmission even using just the most recent year of data. For example, on one path where the historic data showed 4.7 aMW of short term firm transmission, the Committee has modeled that path reflecting 165.1 aMW. The Committee's testimony does not note or explain its inflation of the historic data, the details of which are buried deep in Committee workpapers. The problems in the Committee's modeling show the challenges of hastily adding short-term transmission to the NPC model.

Q. If correctly modeled using accurate amounts derived from a 48-month average, how does the introduction of short-term firm transmission impact NPC in this case?

A. The Committee's system NPC adjustment declines by more than two-thirds, from approximately $9 million to approximately $2.7 million total Company. The Company has included this adjustment in its rebuttal NPC study in this case.

Transmission Imbalance

Q. In CCS 30, the Committee proposes an adjustment of $1.8 million (system) for transmission imbalances. What is the basis for this adjustment?

A. The Committee alleges that the Company benefits from providing transmission imbalance services in its control areas. The Committee imputes a "financial" adjustment which it alleges is equivalent to the benefit. The Committee attempts to support this adjustment by claiming that the Company's NPC reflect the costs of providing imbalance services, but not the benefit.

Q. Does the Company benefit from providing imbalance services?

A. No. Imbalance is a service the Company is required to provide as a control area operator and the price and terms of the service are subject to FERC approval. The terms and price are not set at a level that provides a benefit to the Company, but to compensate it for the costs of providing the service.

Q. Please explain why the Company does not benefit from providing imbalance services.

A. As long as the imbalance energy tariff is based on the market price index, as it is today, rather than the incremental and decremental generation price, the Company will not benefit from providing imbalance services. If the Company receives additional energy within an hour because a party generates more than it schedules, the Company cannot sell it because of a lack of a liquid within-hour market. The Company reacts operationally by backing down gas, coal or hydro plants, which would only be running if its variable cost was less than market. On the flip side, if the Company needs to supply extra energy within the hour because the party generates less than it schedules, then the Company serves it by either picking up generation that was held back to accommodate these types of contingencies, or buying mid-hour in real time, which is a very thin market. By holding back resources in anticipation of this situation, the Company is forgoing the value of monetizing that generation in all hours of the year.

The Committee's adjustment assumes that the Company benefits from each and every imbalancing transaction at a level that is equal to the full amount of the imbalance discount or premium. This assumption is false because of the market realities associated with either liquidating the value of energy it does not know it has or acquiring extra energy to serve load it does not know it has. In addition, the Company is unaware if it received or delivered imbalance energy until after the fact. It would be impossible to make a sale or avoid a purchase under these circumstances.

Q. Does the same hold true whether the Company is providing imbalance services under its FERC OATT tariff or providing the service under legacy transmission contracts?

A. Yes. While the Committee alleges that the Company retains the imbalance premiums or discounts from legacy transmission customers, the point is that these charges still cover only the cost of providing the imbalance service. They do not provide an incremental benefit to the Company.

Q. Does the Committee's adjustment reflect highly inflated imbalance premiums/discounts?

A. Yes. The Committee's adjustment is based upon the assumption of a ten percent imbalance premium/discount, but the imbalance charge under the legacy contracts is only five percent. Additionally, the Committee assumes that an imbalance charge is assessed for every imbalance transaction. In fact, the legacy contracts have an imbalance deadband so that actual generation must differ by more than five percent from their load before charges apply. Because most imbalance transactions are managed within the deadband, the actual imbalance charges under the legacy contracts are small and do not offset the costs of providing imbalances services in the deadband.

Q. The Committee alleges that the Company includes the cost of providing imbalance services in GRID. Is this true?

A. No. The Committee's statement is incorrect and misleading. If the Company did include imbalance service in GRID, it would have to hold back generation in all hours as a standby resource to be ready to provide imbalance energy and would need to back down existing generation during hours when imbalance energy were received from third parties. Both of these adjustments would increase NPC. The Company does not model any transmission imbalances in GRID because these are inconsistent with normalizing logic. This is another reason why the Committee's adjustment is unwarranted and unfair.

Q. Why did the Commission approve a transmission imbalance charge in the previous case?

A. The Committee proposed the charge as one of several corrections to the Company's transmission modeling in that case. The Company conceded the other corrections and failed to rebut this adjustment specifically. The Commission appeared to approve this adjustment as a modeling error, but this adjustment is different in kind from the other adjustments it was grouped with. Imputing revenues for transmission imbalances is itself erroneous, when the only revenues the Company receives for imbalance services are, at best, compensatory to its costs of performing the service and when none of those costs are reflected in the NPC study.

West Valley Reserves

Q. The Committee's final adjustment for transmission and ancillary services is CCS 28, West Valley Reserves. What is this adjustment?

A. The Committee alleges that the Company has improperly included costs for providing reserves to the West Valley plant even though the West Valley lease has terminated. The Committee proposes to remove the costs of reserves, $460,501 (system) or $184,817 (Utah).

Q. Is there any basis for this adjustment?

A. No. The Company is required to hold reserves for all resources in its control area, including West Valley.

Q. Does the Company's revenue requirement include revenues related to the West Valley reserves?

A. Yes. The Company included an adjustment on page 3.8 of Exhibit RMP___(SRM-1SS) to add additional revenues relative to providing reserves to West Valley. This adjustment adds $349,049 total Company, or $140,763 on a Utah basis. The Committee's adjustment is further flawed because it only removes costs and not the associated revenues.

Commitment Logic/Start Up Fuel Costs (CCS 1-8)

Q. Please summarize the Company's current approach to screening its gas-fired plants to prevent uneconomic dispatch of these units.

A. The starting place for the Company's screens is the monthly screening methodology approved in the 2007 rate case Order, including the incorporation of fuel costs associated with the additional start ups required by the screens. The

Company enhanced these screens in this case by setting the screens sequentially for the major gas-fired units and including specific screens for each of the plants. This is described in my Second Supplemental Direct Testimony.

Q. What is the Committee's response to the Company's screening methodology in this case?

A. The Committee acknowledges that the Company "has now adopted a more rigorous methodology for computing the screens." CCS 4D Falkenberg at 12, lines 348-49. Nevertheless, the Committee proposes several major adjustments associated with the screens.

Q. Has the Company accepted any of the Committee's adjustments on commitment logic?

A. Yes, the Company has accepted the aspects of the adjustments which it believes will reasonably enhance the methodology approved in the 2007 rate case Order. First, the Company has agreed to include the Gadsby units in the screens. Second, the Company has agreed to include start up costs as a part of the screening methodology. Together, these adjustments decrease system NPC by $4.1 million.

Q. Does the Company reject other aspects of the Committee's adjustments on commitment logic?

A. Yes. The Committee has proposed to move from monthly to daily screens, misleadingly implying that the Commission approved daily screens for the Company's gas-fired units in the 2007 rate case Order. CCD 4D Falkenberg at 13, lines 365-366. In fact, the Committee proposed monthly screens for the

Company's gas-fired units in the 2007 rate case, the Commission adopted these screens and the Company complied with and enhanced this monthly screening approach in this filing. For call options, the Committee again misleadingly implies that the Commission adopted daily screens, when in fact the Committee proposed daily screens which the Commission rejected in favor of the monthly screens proposed by UAE and accepted by the Company.

Q. Why does the Company object to daily screens?

A. The Committee has not demonstrated that the daily screens add significant new capability to the screens, a standard to which the Committee should be held given the fact that it is arguing for a change in the methodology approved in the 2007 rate case Order. The design and implementation of daily screens is a significant undertaking, one that would require additional investment every time the underlying NPC run changes. The Commission ordered monthly screens in the 2007 rate case and, as enhanced by the Company, these screens have reasonably resolved GRID's uneconomic commitment issues for the gas-fired units and the call option contracts.

Q. Are there other aspects of the Committee's adjustments on commitment logic which the Company contests?

A. Yes. The Committee proposes to reduce the Company's start up costs using an estimate for the energy produced during the start up process and a proxy price for the energy. In a related adjustment, UAE proposes to disallow start up costs altogether.

Q. What is the justification for UAE to remove the additional start up costs?

A. UAE argues that the additional start up costs are incurred due to "tricking" GRID into not dispatching uneconomically, and there is no real world wear and tear. It is correct that the current manual workaround do require forcing the GRID to shut down the plants at various times. However, even if the GRID model can correctly handle the commitment of the plants, there still would be additional start ups of those plants because of the constraints. In any event, the inclusion of start up costs as a part of commitment logic screening was approved in the 2007 rate case Order.

Q. What is the justification for the Committee to impute benefits for start up energy?

A. The Committee argues that the gas units do generate energy during start ups, and that energy can be used to compensate the costs incurred during the start up. It is unclear from their testimony how the Committee determined the amount of the energy that those units would generate.

Q. What other problems are apparent in the Committee's adjustment?

A. The Committee seems to have decided the energy that is generated during the startups is the same as the units' minimum capacity, an assumption that overstates whatever incremental energy might be generated. In addition, during the start up, a unit has to take energy from the grid, a fact which the Committee has not considered in its adjustment. Furthermore, for Currant Creek, the Committee's adjustment implies that the plant can operate more efficiently during start-up than it can in actual operation.

Q. What is your recommendation to the Commission on this subject?

A. The Company has made several adjustments in its commitment logic screens addressing the correct modeling of start up costs and requiring their consideration in the screening analysis. For this reason, the change to valuing start up costs proposed by the Committee and UAE is now much less material in this case. There appears to be no good policy reason for the total exclusion of start up costs as proposed by UAE. The Committee's adjustment is not supported by sufficient evidence to make it a reasonable and accurate adjustment. The Company recommends that the Commission continue to study and review this issue, but reject the associated adjustments as unsubstantiated in this case.

Duct Firing (CCS 19-20)

Q. Has the Company improved its approach to modeling duct firing in this case?

A. Yes. As outlined in my Second Supplemental Direct Testimony, the Company added screens to ensure that duct firing units could not run when the underlying unit is not running.

Q. Does the Committee propose further adjustments for duct firing?

A. Yes. The Committee proposes adjustments designed to prevent duct firing from operating when the Lake Side and Currant Creek units are running at minimum levels.

Q. What is the Company's response to these adjustments?

A. The Company agrees with the Committee that duct firing is not correctly modeled in the current filing. While the Company does not agree with the Committee's proposed solution, it is willing to adopt it on an interim basis in this case, pending further investigation of the issue by the Company.

Forced Plant Outages (CCS 18)

Q. The Committee recommends removal of five outages from the calculation of plant availability figures. Do you agree the outages were caused by imprudence?

A. No. In its testimony, the Committee references an Oregon Commission order as precedent for these types of adjustments. However, the Oregon Commission was careful to distinguish between management failure and employee error, finding that only management failure could form the basis of a prudence disallowance. The Company, as stated by the Committee, has excluded the two management failure items from the Oregon proceeding from the forced outage rate in this case on a proactive basis. The additional five outage items raised in this adjustment, however, were never presented to the Oregon Commission. None involve "management failure" or any other basis for a finding of imprudence.

Q. Is there a better way to determine whether "management failure" has occurred in the Company's plant maintenance practices?

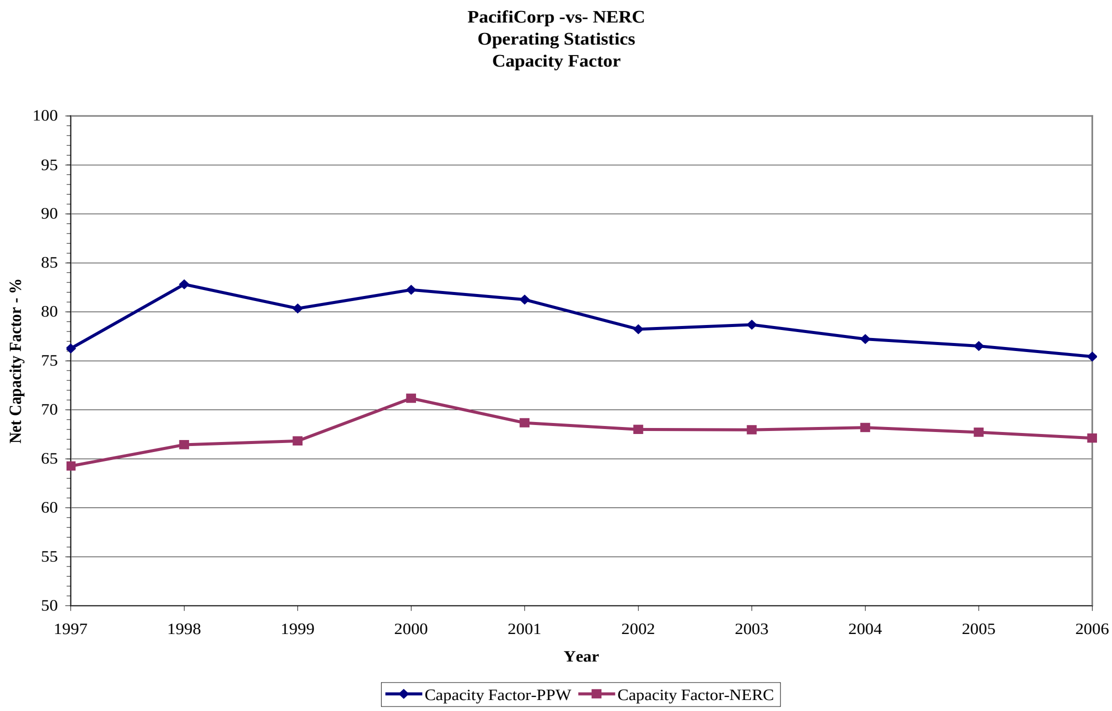
A. Yes. Rather than evaluating hundreds of outages to determine whether they involve evidence of imprudence, it is more efficient and fair to measure the effectiveness of the Company's operations by measuring performance against a peer group. This allows the Commission to look at overall performance against all similarly situated utilities and has the benefit of recognizing better than expected performance by the Company. To be meaningful, this comparison must be conducted on a fleet-wide basis, not on a selective plant-by-plant basis, a proposal that the Committee advanced but ultimately withdrew in the 2007 rate case.

Q. What statistics should be considered in doing this comparison?

A. The key statistics are capacity factor, equivalent availability and planned outage factor. The most recent statistics available are for calendar year 2006. When the Company compares its performance against the NERC/GADS data, it creates a peer group by simulating a fleet of similarly sized units so that the comparison produces meaningful data.

Q. How does the capacity factor of the Company's fleet compare to the NERC/GADS peer group?

A. Capacity factor is the measure of actual output compared to the possible output. Therefore, the higher the capacity factor the more the plant has operated at or near its maximum capacity. The Company's fleet has a capacity factor that is greater than the NERC/GADS peer group as can be seen in the graph below.



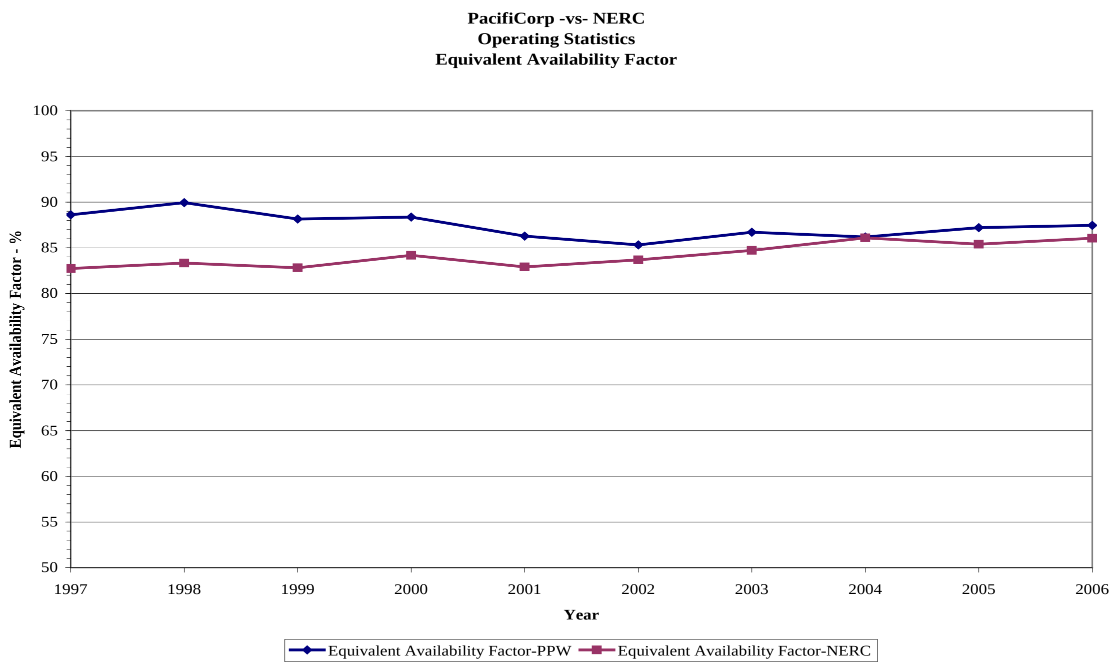
By operating the fleet at these high capacity factors, the Company is able to provide greater benefit to its customers by supplying a low cost source of energy. Looking at the four-year average ending December 31, 2006, the Company fleet had a capacity factor of 76.97 percent versus the NERC peer group with a capacity factor of 67.74 percent. The difference in capacity factor represents approximately 724 MW of capacity. This represents a substantial benefit to customers.

Q. The Company's capacity factor for the four-year period ending December 31, 2006 is 9.23 percent greater than the NERC peer group average. What is the approximate value associated with the Company's above average capacity during this period?

A. The value of the power associated with the Company running above the NERC peer group capacity factor for the four-year period ending December 31, 2006 is approximately $246 million. These savings have helped the Company maintain relatively low net power costs compared to other utilities.

Q. How does the equivalent availability of the Company's fleet compare to its NERC/GADS peer group?

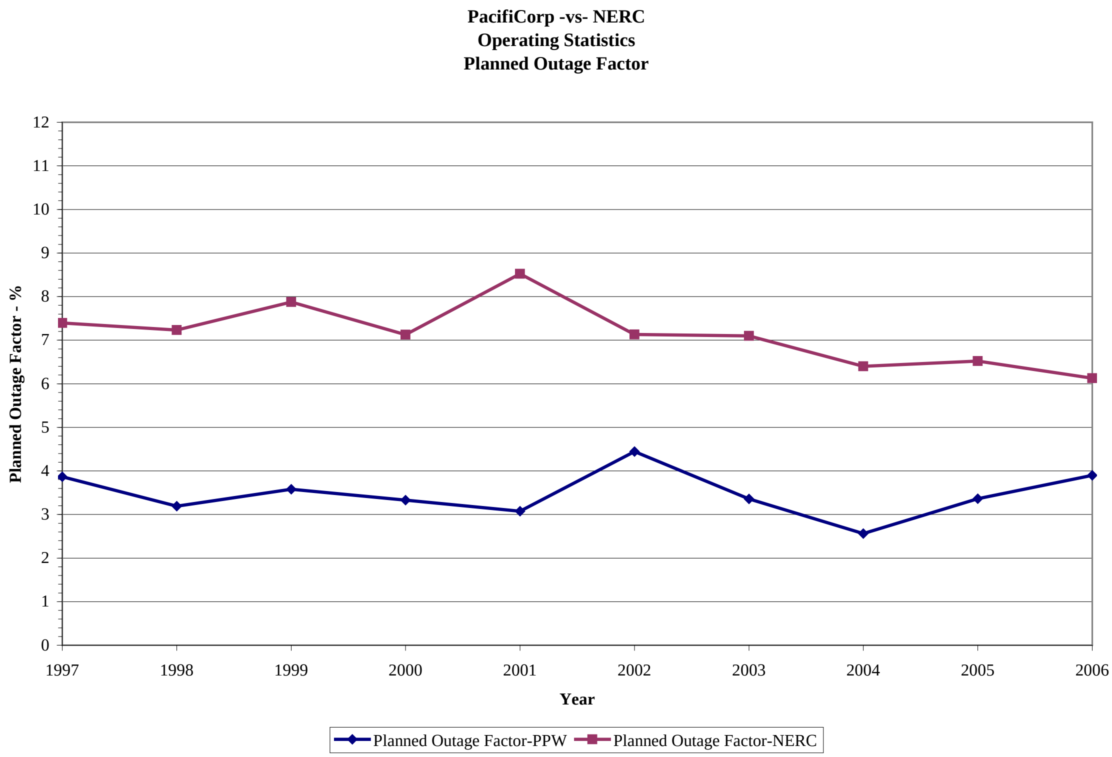
A. Equivalent availability is a measure of the optimal energy that could have been generated during a given report period. This eliminates the bias of market conditions. It can be seen from the graph below that the Company fleet out performs its NERC peer group.



Equivalent availability also takes into account all the reasons a plant could be off-line, i.e. planned outages, planned de-rates, forced outages, maintenance outages, equivalent forced de-rates and equivalent maintenance de-rates. By looking at equivalent availability, it removes the bias of placing an outage or restriction in a different category than the peer group. For example, it does not matter if an outage is classified as maintenance or forced; they are all treated equally in equivalent availability.

Q. How does the planned outage factor of the Company's fleet compare to its NERC/GADS peer group?

A. The planned outage factor takes the amount of planned outage hours over the period hours. This is a measure of the percentage of time the planned was off-line for a scheduled maintenance outage. The Company's fleet has less planned outage hours than its NERC peer group as can be seen by the graph below.



Looking at the four-year average ending December 31, 2006, the Company's fleet had a planned outage factor of 3.29 percent as compared to a planned outage factor of 6.54 percent for the NERC peer group. This difference equates to a difference of 5.82 TWh of generation (using the average fleet capacity of 6,640 MW and the fleet capacity factor of 76.97 percent) over the four-year period.

Q. What do you conclude from these performance statistics that compare the Company's plant operations to other like-sized plant operators?

A. The Company's plant operations are consistently better than other plant operators and the Company's customers are receiving the benefits of this higher level of output in reduced NPC.

Q. Why should the Commission review the prudence of the Company's plant maintenance on a system basis, rather than an individual outage basis?

A. For three reasons. First, the approach proposed by the Committee is asymmetrical where only subpar performance is adjusted and exemplary performance is not rewarded. Second, the only comprehensive way to evaluate a Company's operation is to look at it as a whole and compare it to peer groups. Third, the Oregon Commission order upon which the Committee relies acknowledged that imprudence was a function of management failure, not individual mistake. The best way to judge the efficacy of management is to review plant maintenance on a system basis, not a one-off basis.

Currant Creek Forced Outage (CCS 18)

Q. The Committee proposes to reduce the Currant Creek forced outage rate because it is a cycling plant. Do you agree with this adjustment?

A. No. The Committee's proposal assumes that when a gas plant is out of service for a forced outage, the outage should only count during the day. In other words, the plant should be assumed to be available during the night-time hours even though the plant is broken down. The proposal is neither physically or logically practical and is inconsistent with the Generating Availability Data System ("GADS") reporting requirements.

Heat Rate Curve Adjustment (CCS 21)

Q. What do you conclude from reviewing the Committee's testimony on a heat rate adjustment?

A. I presented an exhaustive discussion of this issue in my Second Supplemental Direct Testimony. The Committee has ignored the evidence I presented on this issue and continues to propose heat rate curves that are not reflective of the Company's thermal fleet. Rather than continue competing equations and examples of why each heat rate plant scenario is right or wrong, I propose a more practical approach to this issue.

Trying to capture actual power system operations in a computer model requires reasonable simplifying assumptions. No approach is going to perfectly match actual operations. This can only be achieved with an ECAM. In the Committee's first attempt to change this modeling issue, it tried to use a system that was either running at full capacity or completely down. This was rebutted as impractical and certainly not the way the Company's system operates. The Committee came back with a different approach which also fails to simulate the reasonable operation of the Company's system.

Modeling should not be based on artificial inputs that have no basis in fact. And, overall, the model outcomes should be reasonable. I demonstrated in my Second Supplemental Direct Testimony that the Company's approach is reasonable. Comparing actual NPC results to the NPC level set by the model in rate proceedings, it is clear that the Commission approved modeled level has not exceeded the actual level for more than a decade. The Company has used its current approach to heat rate modeling throughout this time.

Q. Does the Committee's argument that the Company overstated the heat inputs of the gas units have merit?

A. No, the comparison between the modeled average heat rates and the actual heat rates of the gas-fired units is not valid. The dispatch of the gas-fired units depends, more than the coal-fired units, on the actual conditions and environment of the system, such as actual load requirements, market conditions, availability of other resources, and spark spread between the prices of natural gas and electricity. Even the Committee recognizes that the gas units cycle more often. Because of these facts, the actual dispatch is expected to be different from the normalized dispatch, which leads to different heat inputs of the units making it difficult to compare actual and normalized heat rates for gas plants.

Minimum Load Deration (CCS 21)

Q. The Committee suggests that unless the minimum generation level of thermal plants is derated, then the derated maximum generation could be below the minimum generation. Is this a possibility?

A. No. The hypothetical example provided by the Committee is irrelevant and misleading. The Currant Creek example assumes monthly outage rates, which are not used by the Company since the Commission adopted annual outage rates in the 2007 rate case Order. Both examples represent a situation that would never occur on the Company's system (i.e. a unit with an annual outage rate of 50 percent). No thermal unit in the Company's fleet has an annual outage rate greater than 16 percent and no plant has a spread between the minimum generation level and the derated maximum of less than 14 percent. There is no mathematical possibility that could result in the derated maximum generation being below the minimum generation.

Q. Does the Committee introduce any new arguments on the subject of minimum load deration?

A. No. The arguments presented by the Committee are not new but do not address the fundamental problem with the adjustment that allows thermal plants to run at levels they physically are not capable of achieving. The Committee suggests that since the Company's method restricts the thermal units from running at levels they are capable of running, the Company should relax the restrictions so that those units may run at levels they are not capable of running. This is an irrelevant argument that does not negate the serious flaw in the Committee's proposal.

Wind Integration – UAE

Q. Please describe the adjustment to the wind integration charge proposed by UAE.

A. UAE has proposed to eliminate the wind integration charge of $1.16/MWh for the wind facilities in the Company's control area, using a different methodology than what was used in the Company integrated resource plan ("IRP") and was adopted by the Commission in the 2007 rate case Order. The adjustment would reduce the Company's NPC by $1.2 million on total Company basis, which is the equivalent of reducing the Company's wind integration charge to $0.85/MWh.

Q. Please explain why the UAE adjustment should be small, if there should be any.

A. The two methodologies of modeling the wind integration charges—modeling the costs of extra reserves or assessing a wind integration charge—are similar. Both are designed to capture the impact of the uncertainty in wind generation within the hour. Such uncertainties can be either modeled in a way similar to follow the load fluctuations within the hour, or captured outside the model based on an estimated charge.

Q. Why does the Company use the wind integration charge approach?

A. The Company uses a charge that was developed in the IRP based upon a significant amount of stochastic studies. The Company elected to use this method because of the complicated nature of the wind profiles and location of the wind resources that are in the Company's control area, owned or non-owned, and their possible offsetting effect with the uncertainty in the load that Company serves.

Q. If the two wind integration approaches are expected to be close, why was UAE's adjustment so big?

A. Because the UAE has made the assumption that the reserve requirements of the wind facilities in the Company's control areas are about 26 megawatt on average, and split evenly between east and west.

Q. Is the amount of the adjustment reasonable?

A. No. I provided information in my Second Supplemental Direct Testimony that the Company's integration charge is low relative to those of the BPA and Portland General Electric, and the BPA recently announced that it intended to substantially increase its integration charge. At a minimum, any proposed methodology change that reduces the Company's wind integration charge should clearly identify why the Company's wind integration charge should be significantly lower than other utilities.

Q. Are there specific concerns the Company has with this methodology?

A. Yes. UAE has proposed holding extra reserves in GRID rather than using a specific $/MWh charge for integration which was developed through the integrated resource planning process using stochastic modeling. This is troubling for at least two reasons. First, the location of the reserves is important in terms of the impact on net power costs. UAE has increased reserve requirements equally in both of the Company's control areas. This is inconsistent with the location of the wind facilities that give rise to the additional reserve requirements, the majority of which are located in the east control area and specifically in Wyoming. Conceptually, the cost of providing reserves in the east control area are higher than in the west control area because the west can carry some reserves on hydro resources at a lower cost than carrying reserves on thermal resources.

Second, this methodology would be subject to the vagaries of changes in market prices. Under UAE's method, integration costs would increase with increases in market price and decrease with declining market prices. This would create volatility in wind integration costs. The Commission should understand the impact of market prices on UAE's proposed methodology change prior to implementing it. UAE has not provided any information that could help the Commission understand this volatility.

Q. Do you have any other comments on wind integration costs?

A. Yes. The Company is currently planning to update its wind integration costs. This should be completed in the next couple of months. The Commission should not change course from that set in the 2007 rate case Order until it has the benefit of reviewing the new integration costs being prepared by the Company.

Cholla Capacity (CCS 26)

Q. Please describe the Committee's proposed adjustment to the Cholla maximum capacity rating.

A. The Committee erroneously characterizes the Company's modeling as a derating of the Cholla maximum capacity rating. The maximum capacity of Cholla has been upgraded, but due to the lack of firm transmission to move that additional capacity to its system, the Company did not increase Cholla's maximum capacity above the amount of its firm transmission rights.

Q. Is it reasonable to conclude that 1.2 MW on average of this extra capacity was made available with short-term firm and non-firm wheeling as claimed by the Committee?

A. No. The Company is limited to 387 MW by its interconnection agreement with Arizona Public Service Company. This limit is not only contractual, but also physical, and it is not possible to schedule any capacity above that level.

Q. Has the Company double-counted the capacity reduction as claimed by the Committee?

A. No. The Committee has mixed up actual operation with the deration method used for forced outages. In actual operations, Cholla capacity is limited by the transmission constraint of 387 MW. The extra 3 MW associated with the capacity uprating of Cholla cannot be delivered to the Company's power system. Adjusting the derated capacity is the equivalent to assuming that the Company has 390 MW of firm transmission rights out of Cholla. This is simply not the case. The Committee's adjustment assumes that Cholla runs at the derated capacity in GRID in actual operations, leaving additional transmission available all of the time. This adjustment does not reflect the realities of the physical system and should be rejected.

Early Access to GRID

Q. How do you respond to the Committee's recommendation to require the Company to provide access to the NPC model at the time of filing a case?

A. I believe this is both unnecessary and impractical. Already, the Company provides its workpapers, GRID model and MDRs soon after its filing. The Company needs a short amount of time after the filing to obtain a protective order, organize the data and files used in the GRID model and manage the logistics of data transfer to the parties. The Committee has not demonstrated that this small delay is prejudicial to it.

Q. Does this conclude your rebuttal testimony?

A. Yes.