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

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

Q. Have you previously filed testimony in this case?

A. Yes. I filed Supplemental Direct Testimony in this case. I also adopted the pre-filed Direct Testimony of Mark Widmer.

Summary of Testimony

Q. Will you please summarize your testimony?

A. I will respond to the adjustments and criticism of the Company's Net Power Costs (NPC) presented by Messrs. Dalton, Falkenberg, Hayet and Higgins. My rebuttal testimony is organized into the following categories:

- An explanation of the reasonableness of the Company's revised system NPC of $1.044 billion, a number which reflects the DPU's NPC recommendation and a slight reduction from the Company's NPC revised to take into account all rebuttal corrections, updates and adjustments;
- An overall discussion of the Company's actual NPC versus what has been and is now included in rates;
- Information about the increases to power costs now prevalent throughout the electric industry and specific data on the Company's power cost increases in the first quarter of 2008;
- The Company's proposal to symmetrically update NPC for both contract

changes and the forward price curve to ensure that the NPC projection in this case reflects the best available information; and

- Responses to the other specific adjustments recommended by the witnesses.

Recommendation for Company's Net Power Costs for this Case

Q. In your supplemental direct testimony, you recommended that the Commission set the Company's system NPC at $1.051 billion for the 2008 calendar year test period in this case. Has this overall recommendation changed?

A. Yes. The Company has reduced its recommended system NPC to $1.044 billion, the same system NPC level recommended by the DPU in this case when coupled with corrections to the filing.

Q. What adjustments were recommended by the DPU?

A. The DPU's proposed adjustments related to Sunnyside Power Purchase Agreement (PPA), planned outage dates in GRID and the Tesoro and Kennecott PPAs. These adjustments, along with corrections to the filing, result in a reduction of approximately $7 million to system NPC.

Q. Why have you decreased your system NPC recommendation to $1.044 billion?

A. Since I filed supplemental direct testimony on March 14, 2008, there have been two relevant developments. First, we received the results for the first quarter of 2008, where actual power costs exceeded the level projected in my supplemental direct testimony by 17 percent. Second, we received the testimony of the intervenors, containing a number of adjustments to lower net power costs. As discussed below, the Company agrees that some of these adjustments are reasonable and disputes others.

The Company's revised NPC modeling demonstrates that the net of these two developments—higher costs than projected on the one hand and various modeling adjustments on the other—produces a slight decrease in system NPC to $1.047 billion. Because this result is in the general range of the $1.044 billion NPC the DPU recommended, and because DPU's NPC provides a $3 million cushion for further updates or corrections to the filing, the Company is willing to accept this recommendation for system NPC in this case.

Q. Have you produced an exhibit that shows the derivation of the $1.044 billion system NPC using either the DPU case or a comprehensive modeling of all corrections, updates and adjustments?

A. Yes. Exhibit RMP___(GND-1R-RR) shows the adjustments that support the recommended system NPC of $1.044 billion under two alternative approaches. One reflects the DPU's adjustments, with corrections to the filing. The other calculates NPC factoring in all proposed adjustments and applicable updates. While the calculations are different, both produce similar system NPC levels.

Q. Would system NPC of $1.044 billion produce a reasonable result in this case?

A. Yes, although rates will still not cover the Company's actual power costs. The Company's most recent case filing, which was settled, sought system NPC of $813 million. While the actual NPC in rates may be lower than this as a result of the stipulation, the Company has conservatively assumed $813 million as the current system NPC baseline. If the rate change from this case occurs by

September 1, this baseline, when combined with the Company's filed NPC of $1.044 billion, would produce a total NPC for calendar year 2008 of approximately $890 million (i.e., 8 months at $813 million and 4 months at $1.044 billion). This 2008 NPC is $96 million less than Mr. Falkenberg's 2008 NPC projection of $986 million (the Final GRID Result in Table 1, less CCS 4.16 and 4.20, which were omitted from the Result), $85 million less than the Company's actual power costs for calendar year 2007 of $975 million and $90 million less than $980 million NPC in rates in Oregon derived from a calendar year 2008 test period. A full allowance of the Company's requested power costs in this case will still leave the Company in a position of cost under recovery for 2008. Steadily increasing costs portend the same for 2009.

For ease of reference, the following table summarizes the NPC recommendations of the parties in this docket and NPC benchmarks discussed in my testimony.

System NPC recommendations CY 08 test period		
Company recommended NPC	$1.044 billion (from modeled NPC of $1.047 billion)	
DPU recommended NPC	$1.044 billion	
CCS recommended NPC	$986 million	
Benchmarks		
NPC now in rates	$813 million	Exhibit RMP____(GND-2R-RR)
Actual NPC CY 2007	$975 million	Exhibit RMP____(GND-2R-RR)
Actual power costs 12 months ending March 2008	$1.024 billion	Exhibit RMP____(GND-3R-RR)
Projected 2008 NPC (3 months actual/9 months CCS model)	$1.060 billion	Exhibit RMP____(GND-4R-RR)
Oregon TAM updated for Utah loads	$1.032 billion	Exhibit RMP____(GND-5R-RR)
Oregon TAM updated for Utah loads and for load increases during the first three months of CY 2008	$1.060 billion	Exhibit RMP____(GND-5R-RR)

Summary of the Company's Historical Recovery of NPC in Rates

Q. How important is the Company's ability to recover NPC to its opportunity to earn its allowed rate of return?

A. Recovery of the Company's NPC represents the single largest component of revenue requirement. Mr. Walje's Direct Testimony noted that NPC accounted for nearly one-third of the total revenue requirement increase proposed in this case. To the extent these costs are understated in the Company's prices, it is virtually impossible to compensate for this shortfall with efficiencies from other areas of the operation.

Q. Please provide detailed analysis of the Company's actual NPC versus what was recovered in Utah rates over the last 16 years.

A. Exhibit RMP___(GND-2R-RR) consists of two charts depicting the actual NPC that the Company has incurred over the last 16 years with the NPC which have been included in rates by this jurisdiction. Like the example discussed above, when a case was settled without expressly stating the system NPC baseline, the Company assumed that system NPC in rates is what was reflected in the Company's filing.

Q. Please describe the results of Exhibit RMP___(GND-2R-RR).

A. This Exhibit shows the Company has consistently spent more on net power costs to serve its customers than it has recovered in rates. However, the trend and magnitude of this situation in recent years is the most significant aspect of this exhibit. The historical recoveries from 1990–1999 had some years of under- and over-recovery but the total dollar amounts were generally fairly small. In 2000–

2001, the large under recovery is explained in part by the power crisis (and was partly offset by deferred accounts for power costs). But in 2002–2007, the amount of NPC included in the Company's rates consistently has been below its actual costs, in every year by a wide margin. In fact, the difference in 2007 is in excess of $160 million.

Q. What is your general observation about what has caused the Company's actual costs to outpace the level included in rate?

A. NPC have been steadily increasing industry-wide, so the use of partial or full historical test years contributes to the under-recovery. In addition, as discussed in greater detail below, GRID and other linear programming power cost models fail to capture all actual costs by assuming optimal system operation with some, but not all, of the constraints that the Company faces on a real-time basis.

These factors are exacerbated when, as in this case, intervenors: (1) propose adjustments that selectively update for known costs changes which reduce NPC after the filing was made without a corresponding look at all of the cost changes that have occurred which would increase NPC; (2) selectively use historical trends for certain costs inputs without a corresponding look at costs trends that would increase costs; and (3) propose modeling adjustments without a demonstration that the Company's modeling approach is imprudent or unreasonable.

NPC Using Most Recent Actual Results

Q. In litigating the test period for this case, parties expressed concern about reliance on forecasted instead of actual information. Have you prepared an exhibit reflecting the Company's annual actual power costs through the first quarter of 2008?

A. Yes. The Company's actual NPC results for calendar year 2007 were $975 million. Consistent with the Company's projections in this case, the Company's actual NPC results for 12 months ending March 31, 2008 reflect steadily increasing costs. The Company's actual NPC results for this period were $1.024 billion. See Exhibit RMP___(GND-3R-RR). This is $38 million more than the system NPC Mr. Falkenberg is recommending in this case for calendar year 2008.

Q. Is it unreasonable for Mr. Falkenberg to recommend approval of a power cost number which is $38 million below what has been incurred for the most recent actual period?

A. Yes, for two reasons. First, given load growth and the internationally publicized increases in the costs of energy, a declining cost scenario for the Company's NPC in 2008 is inherently suspect. Second, Mr. Falkenberg's adjustments mainly deal with model input and logic issues which have no impact on actual results less any imprudent costs.

Q. Have you prepared a forecast for 2008 NPC using this actual information from the first quarter of 2008?

A. Yes. Because the monthly NPC showing Mr. Falkenberg's recommended $986 million is not available, I selected an NPC report from among Mr. Falkenberg's numerous files and approximated the monthly NPC. Then, I replaced the first three months of the approximated NPC with the actual NPC that the Company has incurred in the three months. See Exhibit RMP___(GND-4R-RR). This results in a more current look at NPC for calendar year 2008. Using 3 months actual and 9 estimated net power costs, Mr. Falkenberg's model produces NPC of $1.060 billion, an amount well in excess of the Company's proposed NPC in this proceeding.

Q. Does the $1.060 billion result of this NPC study support the reasonableness of the Company's current $1.044 billion system NPC recommendation?

A. Yes. The study demonstrates that Mr. Falkenberg's adjustments are totally offset by increases in the Company's actual power costs reflected in the first three months of 2008.

Q. Do you have other benchmarks that demonstrate that the Company's $1.044 billion system NPC number is reasonable and should be accepted by the Commission?

A. Yes. I have taken the $980 million NPC from the 2008 Oregon Transition Adjustment Mechanism (TAM) order (in which a 2008 test year was used and Mr. Falkenberg was a witness) and updated these results for the loads reflected in the Utah case. This result (which does not reflect the most recent forward price curve) shows system NPC of $1.032 billion. If this number is updated for actual loads reflected in the first three months of 2008, the result is a system NPC of $1.060 billion. See Exhibit RMP___(GND-5R-RR).

Q. What do you conclude from your review of all of these factors?

A. All of these factors demonstrate that the Company's proposed system NPC of $1.044 billion is reasonable. The empirical evidence of the Company's historical and current NPC cost-recovery, as well as the trend of current year costs, support recovery of the Company's requested NPC. While the intervenors have proposed many adjustments to reduce this number, it is important to keep in mind that the majority of the adjustments proposed have nothing to do with prudence of cost expenditures but rather address the input and logic of a linear programming-based model used to forecast the anticipated level of these costs. The arguments for these adjustments might appear reasonable in the abstract. However, when they contribute to a result that significantly understates the Company's actual costs of providing power to customers, the Commission should reject them as inconsistent with basic ratemaking principles.

Post-Filing Updates and Corrections

Q. What costs have been proposed for update in the Company's filing?

A. Parties have proposed to update several QF contracts that have been either changed or consummated after the filing of the case. Parties also recommend updating BPA transmission agreements. The specific updating adjustments proposed are CCS 4.6 (Hermiston Losses); CCS 4.10 (Biomass Non Gen); CCS 4.11, DPU 6.1 and UAE 1.6 (Sunnyside QF); CCS 4.12 (Schwendiman Contract Deferral); CCS 4.27 (Goodnoe Transmission); CCS 4.28 (Borah Brady Transmission); CCS 4.29 (Transmission Cost Escalation) and DPU 6.3 (Tesoro and Kennecott PPAs).

Q. Do you agree that the filing should be updated for these changes?

A. The Company supports these updates as long as the filing is updated symmetrically for both cost decreases and cost increases including, most notably, cost increases reflected in the most recent forward price curve. Exhibit RMP___(GND-1R-RR) reflects the calculations supporting the Company's $1.047 billion system NPC. These calculations include all of the updates proposed by intervenors and an update to the forward price curve, substituting the March 2008 forward price curve for the September 2007 forward price curve used in the original filing.

Q. In addition to your point that power cost updates should be symmetrical in this case, why should the Commission allow the Company to update to the most recent forward price curve in its rebuttal testimony?

A. For several reasons. First, the test year decision has increased the regulatory lag the Company faces in a time of steadily increasing power costs. Updating the forward price curve is one step the Commission can take to mitigate this problem. Second, the Company's forward price curve is used for various regulatory purposes and therefore has been subject to audit for many years. Third, other jurisdictions have allowed updates to power costs for the forward price curve during pending cases without adverse results. Notably, this approach has been used in setting the Oregon TAM for several years. Because Mr. Falkenberg relies on various aspects of the most recent TAM Order to support his adjustments, he should not object to Utah using what has been a relatively non-controversial aspect of the Oregon process.

Q. In addition to NPC updates, have the intervenors raised certain corrections to the Company's filing?

A. Yes. The Company agrees that the following adjustments reflect modeling errors: CCS 4.8 (SMUD Leap Year); CCS 4.21 (Currant Creek Outage Rates) and CCS 4.26 (Self-Supply Non-Owned Reserves). These corrections decrease modeled NPC by approximately $1.5 million total company.

Q. Does the Company have any corrections it proposes to make to its filing?

A. Yes. The Company's original filing included gas swaps and indexed electric transactions, but inadvertently omitted electric swaps and indexed gas transactions. The Company conducts these transactions as a hedge against market risk. To date, no one has challenged the swaps and indexed transactions that are already in the filing. Inclusion of these omitted transactions increases system NPC by approximately $3.2 million.

Company Responses to Specific Adjustments – Overview

Q. How have you organized your responses to the intervenors' modeling adjustments to net power costs?

A. We have grouped the intervenors' proposed NPC modeling adjustments into two categories.

First, there are adjustments to which the Company agrees in part, but proposes to model through alternative calculations. These are CCS 4.1 through CCS 4.4 (GRID Commitment Logic); CCS 4.14 and DPU 6.2 (Planned Outages); CCS 4.17 (Monthly Outage Rate) and CCS 4.19 (Ramping).

Second, there are proposed modeling adjustments which the Company disputes as inaccurate, unsubstantiated or inconsistent with normalized ratemaking. This includes CCS 4.5 and UAE 1.1 (Call Options); CCS 4.7 and CCS 4.9 (SMUD); CCS 4.15 (STF Arbitrage and Trading); CCS 4.15 and CCS 4.16 (Hydro Modeling); CCS 4.18 (Bridger Error Outages, addressed in the separate testimony of Mark Mansfield); CCS 4.20 (Duct Firing Reserve Capability); CCS 4.22 (Heat Rate Modeling Adjustment); CCS 4.23 (Minimum Loading Deration); CCS 4.24 (Station Service); CCS 4.25 (Wind Integration Charges, addressed in the separate testimony of Mark Tallman); and UAE 1.1 (Currant Creek Minimum Generation).

Q. Does the Company's Exhibit RMP____(GND-1R-RR) demonstrate how the Company has reflected the adjustments and related offsets for commitment logic, planned outages and ramping?

A. Yes. Taking these adjustments and related offsets into consideration after the case updates and corrections produces a slightly reduced system NPC of approximately $1.047billion.

Company Responses to Partially Contested Adjustments

CCS 4.1 through CCS 4.4 (GRID Commitment Logic)

Q. Please explain Mr. Falkenberg's commitment logic adjustments.

A. Mr. Falkenberg contends that the GRID model's commitment logic is imperfect because, at certain times, it dispatches three of the Company's gas plants, West Valley, Currant Creek and Lake Side, in a manner that fails to optimize the system. Specifically, he complains that GRID dispatches the gas plants at times when there is no firm transmission available in the model to take the power to loads or markets. While GRID backs down the gas plants to minimum levels, it also backs down coal plants to compensate for the excess power. This causes NPC to increase.

Q. What specific adjustments does Mr. Falkenberg propose?

A. Mr. Falkenberg proposes a daily "with and without" test for West Valley to determine whether power costs are higher when West Valley is dispatched. For Currant Creek and Lake Side, he proposes a "night-time screen," manually preventing the units from dispatching during certain hours at night. He also proposes to increase O&M expense for Currant Creek and Lake Side to account for the costs of the additional start-ups modeled.

Q. Does Mr. Falkenberg ask the Commission to require changes to the GRID model for future cases?

A. Yes. Before RMP files another case, Mr. Falkenberg asks the Commission to require RMP to either fix the commitment logic in GRID or add non-firm transmission to the model.

Q. Does the Company agree with the basis for Mr. Falkenberg's adjustment?

A. No. The premise of Mr. Falkenberg's adjustment is that "industry standard models assume optimal operation or resources and cost minimization despite the fact that it can't always be achieved in practice." Mr. Falkenberg cites no support for this statement from Utah or elsewhere. And he makes no attempt to reconcile the "optimal operation" standard he proposes with the normal prudence standard by which this Commission judges utility business operations. Indeed, he undermines the appropriateness of the "optimal operation" standard acknowledging that "it can't always be achieved in practice." When a model assumes a level of perfection in system operations that cannot be achieved in real-time, the model will always understate actual net power costs.

Q. How does Mr. Falkenberg defend his claim that power costs should be based on an "optimal operation" standard?

A. Mr. Falkenberg claims that there is no other way to model and measure power costs. I disagree. A prudence standard works as well to measure a utility's power costs as it does to measure other utility costs.

Mr. Falkenberg also alleges, again without any support, that there is no evidence that utilities systematically under-recover costs under an optimization model. In this case, however, the Company has demonstrated that it has under-recovered its power costs in rates every year since 2000. This appears to be the result of a disconnect between system optimization in the GRID model and the real-world challenges of operating the Company's complex generation and transmission system. For example, GRID has the ability to buy 1 MW blocks of power to balance the system, whereas real-time operation requires much larger blocks which in turn require selling the shoulder period at potentially less than cost.

Q. Please explain the rationale for normalized NPC and what you would expect to see in actual results versus normalized ratemaking.

A. Normalized ratemaking is intended to set costs at a level that would produce full recovery of the system costs under normal conditions. This approach presumes that the Company will have an opportunity to recover its full costs because there is an equal probability of the actual costs being less than normal or greater than normal. The Company's experience since 2000, however, undermines the premise that the Company's risk and reward associated with NPC recovery are symmetrical under current ratemaking practices.

Q. What is your conclusion on the operative standard by which the Commission should set NPC?

A. The Commission should review the reasonableness of the Company's proposed NPC using the same prudence standard it applies to other aspects of the Company's business operations. As a matter of prudence, the Company will generally seek to optimize its system. But there are limits on what the Company can achieve in this regard in real-time operation. The Commission should not hold the Company to a level of perfection in its operation of its system that is impossible for any utility to achieve.

Q. What is your response to the underlying commitment logic issue?

A. The Company agrees that GRID should simulate normal prudent operation of the system. Absent unusual circumstances, the Company would not run its gas units in a manner that would cause its less expensive coal plants to back down. To the extent that GRID systematically dispatches resources in this manner, the Company agrees that the model needs to be adjusted.

Q. How has the Company addressed this issue to date?

A. The Company has addressed this issue in two ways. First, when it has become clear that the model is systematically dispatching units in an uneconomic manner, the Company has applied manual workarounds (i.e. turning off the ability of the model to dispatch a certain unit at a certain time). Second, the Company has worked to refine and improve GRID's commitment logic in the last two upgrades to the model to eliminate the need for such manual workarounds.

Q. Has the most recent version of GRID completely resolved this issue?

A. No. The most recent version of GRID addresses and ameliorates the issue but did not resolve it in all cases.

Q. How does the Company propose to address this issue in this case?

A. The Company agrees that a manual workaround should be applied to prevent systematic uneconomic dispatch of the West Valley, Currant Creek and Lake Side plants.

The West Valley plant is a relatively minor issue because it was not covered in the original test year in this case and it will not be in NPC after this case. To resolve the issue in this case, the Company proposes to apply a light load hour screen to West Valley.

With respect to Currant Creek and Lake Side, similar to Mr. Falkenberg's recommendations, the Company proposes to apply a 6-hour night-time screen to theses units. The Company believes that the increased O&M charge calculated by Mr. Falkenberg for the additional unit start-ups associated with this manual workaround is reasonable. The workaround lowers NPC by $18.6 million total company, while the O&M charge increases NPC by $9.4 million.

Q. How does the Company plan to address this issue in future filings?

A. The Company is now working on additional refinements to GRID's commitment logic. Until this work is complete, RMP will apply manual workarounds to the model to address uneconomic dispatch.

Q. Does the Company agree that the model should include non-firm transmission as a means of potentially addressing this issue?

A. No. The Company does not agree that it is appropriate to model transmission which might or might not be available to the Company. The impact of speculative modeling of non-firm transmission would be to assume an even higher level of perfection in the Company's system operations than is currently the case in the model and further exacerbate the disconnect between modeled and actual net power costs.

CCS 4.14 and DPU 6.2 (Planned Outages)

Planned Outages

Q. Please describe the adjustments to planned plant outages proposed by Messrs. Falkenberg and Dalton.

A. Mr. Falkenberg contests the schedule the Company used for its planned outages and substitutes his own schedule. Mr. Dalton's adjustment also questions aspects of the Company's planned outage schedule, specifically outages that have been scheduled in a manner that deviates from historical practice. Mr. Falkenberg's adjustment decreases NPC by $11 million total company; Mr. Dalton's adjustment decreases NPC by $4.4 million total company.

Q. Do you agree with the adjustment methodology that Mr. Falkenberg is proposing?

A. No. Mr. Falkenberg's proposed outage schedule does not take into consideration all of the factors to be considered in outage planning. It is clear from page 54 of

Mr. Falkenberg's testimony that the primary criteria he used was to align the maintenance schedule with the lowest market prices. As a result, his adjustment lowered net power costs by more than twice the level of Mr. Dalton**.**

Q. Do you have any comments on how Mr. Dalton's adjustment is calculated?

A. Yes. As indicated in his supplemental direct testimony, Mr. Dalton incorrectly included adjustments made to Goodnoe Hills and Glenrock wind facilities in the adjustment for planned maintenance outages. Mr. Dalton also appears to have incorrectly included adjustments to the Tesoro contract and Seven Mile wind facility in his adjustment for planned maintenance outages. Removing these, DPU's adjustment to Company's planned maintenance is a reduction in NPC of $4.4 million total company.

Q. Do you support Mr. Dalton's general approach?

A. In general, yes. We agree with Mr. Dalton's point that the planned outage schedule in the current case deviates in some ways from the Company's historic practices, particularly by scheduling outages in January and February. To respond to this point, we have developed an alternative planned outage schedule for this case.

Q. Please describe your new proposed planned outage schedule for this case.

A. The revised planned outage schedule removes all planned outages from the months of January and February and smoothes them into the spring and fall months of the schedule. In this new schedule, we take into account all considerations the Company addressed in CCS data request 6.15. Application of this new outage schedule reduces modeled NPC by $1.7 million total company.

CCS 4.17 (Monthly Outages)

Q. Please explain Mr. Falkenberg's proposed monthly outage rate modeling adjustment.

A. The proposed adjustment would reverse the company's <u>monthly</u> modeling of forced outage rates and substitute <u>annual</u> forced outage rates. Mr. Falkenberg believes his adjustment is appropriate because monthly modeling is not industry practice and outages are random. The adjustment would increase proposed net power costs by $.9 million total company.

Q. Do you agree with the proposed adjustment?

A. Yes, but only if the weekday/weekend split for modeling outages is also eliminated. If the Company reverts to more general, annual modeling of forced outages, there is no justification for the retention of the weekday/weekend split in the forced outage rate.

Q. What is the impact of reverting to an annual forced outage rate and eliminating the weekday/weekend split in the forced outage rate?

A. This change increases modeled NPC by approximately $4.4 million on a total company basis.

CCS 4.19 (Ramping)

Q. Please describe Mr. Falkenberg's ramping adjustment.

A. The Company has added a ramping adjustment to its NPC to account for decreased availability when generating units are started-up and shut-down. Mr. Falkenberg proposes to remove this adjustment, decreasing NPC by $4 million total company.

Q. Please explain why the Company included its ramping adjustment.

A. The logic in GRID assume that generation units can go from full load to zero instantaneously when being ramped down for maintenance, outages or economic shutdown and can go from zero to full load instantaneously when restarted after planned maintenance, economic shutdown and forced outages. In reality, units are not available at full load when ramping down for maintenance, outages or economic shutdown and when ramping up from outages due to the physical capabilities of the units. Generation is lost while a unit ramps to the minimum level required for synchronizing with the power grid and when ramping up to full load, as well as when a unit is being shut down for maintenance or economic shutdown. The Company's ramping adjustment simply reduces thermal availability to reflect generation not available due to ramping.

Q. Mr. Falkenberg claims that the Company's ramping adjustment is contrary to industry practice. Please respond.

A. The only unusual aspect about the Company's treatment of ramping is that it requires a manual adjustment in GRID, since GRID does not include the ability to ramp units as a part of its dispatch logic. However, there is nothing novel in factoring in ramping into a generation unit's availability.

Q. Mr. Falkenberg claims that the Company lost this issue in the last Washington rate case. Is this true?

A. It is true that the Washington Commission ruled against the Company on an adjustment that they referred to as ramping. The order makes clear, however, that the analysis of this issue focused on calculation of the forced outage rate, not on the reasonableness of adjusting availability for ramping.

Q. Mr. Falkenberg complains that the Company's method of calculating ramping can mischaracterize a gas unit being held in reserve as ramping. Please respond.

A. First, to clarify any confusion on this point, the only gas plants included in the Company's ramping adjustment are Gadsby units 1, 2 and 3, which are steam units by design. There are no other gas units included in the ramping adjustment.

Second, the Company agrees that its current ramping calculation could inadvertently cover a gas plant being held for reserves. To adjust for that possibility, the Company agrees to remove the Gadsby units from the ramping adjustment. This reduces system NPC by $1.7 million.

Company Responses to Fully Contested Adjustments

CCS 4.5 and UAE 1.1 (Call Options)

Q. Please explain the proposed adjustments for call options.

A. Mr. Falkenberg's proposed adjustment proposes to disallow costs associated with five call option contracts from GRID. He proposes alternative calculations for this adjustment, reducing net power costs by either $2.5 million or $922,660 on a total Company basis. Mr. Falkenberg supports the adjustment on the basis that the Company accepted a similar disallowance in last year's Oregon TAM case.

Mr. Higgins also proposes an adjustment related to the call option contracts, seeking to reduce NPC to account for their uneconomic dispatch. Additionally, he seeks to disallow one of the contracts based on the incorrect understanding that it expired in 2007.

Q. Do you agree with Mr. Falkenberg's proposed adjustment?

A. No. Mr. Falkenberg is seeking to disallow the call option costs without demonstrating the imprudence of these costs. The Company executed the contracts to meet demand and ensure reliable service by providing physical delivery of energy into our Utah load area 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 and should be included in the Company's net power costs.

Q. What is the origin of Mr. Falkenberg's adjustment?

A. In a case involving Portland General Electric (PGE), the Oregon Commission imputed extrinsic value to two contracts that did not dispatch in PGE's model. In this case, the Oregon Commission also adopted a Power Cost Adjustment Mechanism (PCAM) for PGE. In last year's Oregon TAM, PacifiCorp and the Industrial Customers of Northwest Utilities (ICNU) argued about whether and how this precedent should be applied to PacifiCorp. PacifiCorp expressly rejected ICNU's view that the decision implied that unless a contract energy component provides enough benefits to cover the premium, extrinsic value should be imputed. PacifiCorp noted that this argument was illogical, because option contracts are purchased to provide reliability and capture value when market prices increase. When the Company buys an option contract, the Company looks for out-of-the-money contracts that have a lower premium as a means providing reliability while keeping costs low, because the contracts are not expected to be dispatched all of the time. If the Company were to buy in-the-money option contracts, the premium and overall cost would be higher because of the expectation that they would be dispatched most of the time.

Q. How was this adjustment resolved in the Oregon TAM case?

A. Ultimately, because of the Commission precedent in the PGE case and procedural issues unique to the Oregon TAM, PacifiCorp did agree to remove the costs of option contracts if and when removal of the contracts lowered NPC. PacifiCorp noted that several of the contracts that ICNU sought to disallow did not have this impact when PacifiCorp updated the GRID runs.

Q. Is this adjustment applicable to this case?

A. No. Unlike the Oregon Commission, the Utah Commission has never disallowed nor imputed extrinsic value to option contracts, and Mr. Falkenberg has not supported that predicate argument in this case. In any event, the Oregon case that adopted this precedent also involved adoption of a PCAM.

Q. How do you respond to Messrs. Falkenberg and Higgins' contention that the call options are dispatching uneconomically?

A. This is a different issue from recovery of the capacity charges of the call options. While the Company believes NPC should include the capacity charges of these contracts in all cases, the Company agrees that the contracts should not be dispatched in a manner that increases NPC. The Company's preliminary analysis suggests, however, that a screen of the call option contracts would not have a significant impact on NPC in this case. Indeed, when the Company screened the contracts identified by Mr. Higgins (NEBO Heat Rate Option and the

Constellations contracts), the result was an increase in system NPC.

Q. Has Mr. Falkenberg substantiated his call option adjustment?

A. No. Mr. Falkenberg references three different amounts for this adjustment in his testimony. It is not clear how his adjustment of $2,502,690 listed in his Table 1 is determined. The workpaper supporting it, according to Mr. Falkenberg, is the confidential Exhibit CCS 4.7. However, that number is nowhere to be found on that exhibit. The exhibit does show an alternative $922,660 number but does not make clear how that number is derived. Mr. Falkenberg's testimony also references a third number for his adjustment, $3.59 million, without any explanation for it.

Despite a specific request for Mr. Falkenberg to produce organized, auditable work papers, the Company received a huge electronic file from him without any navigation instructions. Even though Mr. Falkenberg eventually produced a basic map to his work papers, the Company was still unable to analyze Mr. Falkenberg's adjustments in detail because of errors in his map and the difficulty of locating the relevant files in the work papers among the many files that had been created by Mr. Falkenberg that appear to have not been used to support any of his adjustments. It is not clear whether any of his option contract adjustments reflect full recovery of the capacity charges of the call option contracts and target only the uneconomic dispatch of the contracts, which is the only basis for any adjustment in this case.

CCS 4.7 and CCS 4.9 (SMUD)

SMUD Pricing

Q. Please explain Mr. Hayet's proposed SMUD pricing adjustment.

A. Mr. Hayet argues that the current revenue imputation at $37 per MWh is not compensatory and the Southern California Edison (SCE) wholesale sales contract, upon which the revenue imputation has been based, expires prior to the start of the test year. He contends that since the revenue the Company is receiving has increased by approximately 6 mills per kilowatt-hour, the amount of imputation should increase by a like amount or 43 mills per kilowatt-hour. He also implies the contract should be looked at regularly for imputation based on current market prices. The adjustment would reduce proposed net power costs by $2.4 million total company.

Q. Please explain the SMUD transaction.

A. As a result of the cancellation of a nuclear project that was never in rate base or otherwise supported by customers, the Company entered into a series of transactions that resulted in the Company acquiring the firm rights to power from BPA in the future. Subsequently, the Company sold these "below the line" BPA firm energy rights to SMUD for a $94 million payment and a power sale to SMUD at a rate that was below the then current market price.

Q. Do you agree with the proposed adjustment?

A. No. Just because the SCE contract has expired does not mean the SMUD contract should be recalculated based on current market rates. These contracts were entered at approximately the same time for a long term period. The price of the

SCE was negotiated at market prices at the time. Therefore, one can assume that the SCE contract sets a fair market price of the SMUD contract. Taking a long term contract price and arbitrarily adjusting it to the current market price makes no more sense than the Company thinking it could adjust the current price to SMUD based on current circumstances regardless of what is in the contract. Further, the adjustment would not be consistent with the treatment of the contract over the last several rate cases, which imputed revenue at $37 per MWh based on the original SCE contract.

Q. Have other Commissions accepted the $37 per MWh SMUD pricing set by this Commission in an earlier case?

A. Yes. The Utah Commission originally determined the $37 per MWh charge for the SMUD contract. While Mr. Falkenberg has regularly challenged this charge, other commissions have always rejected his arguments and opted to follow the Utah approach.

Q. Do you have any other concerns about this proposed pricing adjustment?

A. Yes. The ongoing review of prudence based on new knowledge is not consistent with normal regulatory policy and cost-based ratemaking. If this type of adjustment were to be made, it would also need to be applied generally which would result in significant imputed price increases to contracts such as the Mid-Columbia purchase power agreements and the Hermiston fuel agreements. The Company does not recommend this approach.

Q. What is your recommendation?

A. I believe the revenue imputation should continue at $37 per MWh to be consistent with treatment for the last several years and the regulatory principle that prudence should be based on information available at the time the transaction was consummated.

SMUD Contract Modeling

Q. Please explain Mr. Falkenberg's proposed SMUD contract modeling adjustment.

A. The adjustment proposes to substitute actual data for normalized data. The model assumes for normalized purposes that SMUD will maximize the value of the contract and take the power at the highest cost hours. Mr. Falkenberg proposes to adjust this input to reflect actual contract operation. This adjustment results in a $1.1 million reduction in total company NPC.

Q. Do you agree with the proposed SMUD adjustment?

A. No. The adjustment has two specific problems. First, the adjustment departs from modeling power costs on a normalized basis. Second and more important, it is an example of a one-sided, selective adjustment to the model. If this type of modeling adjustment were adopted, then consistency and fairness requires its application to all other purchase or sale contracts which are modeled in a similar fashion to the SMUD contract. Optimization of the Company's system operations decreases NPC on a net basis. Mr. Falkenberg has not proposed "deoptimization" across the board, which would increase NPC—and potentially undermine Mr. Falkenberg's arguments on GRID commitment logic. Nor has he provided any justification for selective "deoptimization" of the SMUD contract. His argument to change the modeling of the SMUD contract should therefore be rejected.

CCS 4.13 (STF Arbitrage and Trading)

Q. Please describe Mr. Falkenberg's short-term firm arbitrage and trading adjustment.

A. Mr. Falkenberg contends that the GRID model does not cover all of the short term firm (STF) transactions conducted by the Company and fails to properly credit customers for profits associated with STF trading and arbitrage. This adjustment decreases modeled NPC by $3.6 million total company.

Q. Do you agree with this adjustment?

A. No. GRID reflects a normalized level of STF transactions, including transactions that optimize the system through trading and arbitrage activities. This adjustment proposes to impute actual trading and arbitrage profits to lower NPC without proposing to adjust NPC for other actual costs that would increase NPC. On balance, even with the modest trading and arbitrage margin the Company has recorded historically, its net power costs on an actual basis remain far more than what is in rates. It is unfair to further exaggerate that under recovery by selectively lowering NPC for actual costs and revenues, especially without a reciprocal commitment that customers will cover any future losses associated with STF trading and arbitrage activities.

Q. Was this adjustment imposed in Oregon?

A. Yes. In response to a proposal from Staff and intervenors to impute more than $16 million (Oregon) in STF trading and arbitrage revenues, the Oregon Commission imposed a $0.8 million adjustment. The Company disagrees with the adjustment for the reasons just stated and, after resolution of an Oregon Commission docket on stochastic modeling, the Company intends to further contest this issue.

CCS 4.15 (Hydro Modeling)

Q. Please describe Mr. Falkenberg's hydro modeling adjustment.

A. Mr. Falkenberg alleges that the Company's VISTA model for modeling normalized hydro generation overstates the likelihood of extreme hydro conditions. He recommends that the Commission eliminate this alleged bias by changing the weights for the Wet, Median and Dry cases to those he developed based upon historical data. This adjustment lowers modeled NPC $3.5 million on a total company basis.

Q. Why did the Company incorporate the VISTA model into its power cost modeling?

A. The Company began using the VISTA model to more accurately reflect changing operational characteristics of river systems compared to using a simple historical average of generation.

Q. How does the Company model normalized hydro using the VISTA model?

A. VISTA currently has three exceedance levels: 25 percent, 50 percent and 75 percent. A 25 percent exceedance level means that the Company has a 25 percent chance of exceeding that level of generation (i.e., a "wet" year); a 75 percent exceedance level means the Company has a 75 percent chance of exceeding that level of generation (i.e., a dry year). To set normalized power costs, the Company runs the GRID model using the three exceedance levels and averages the results.

Q. What is Mr. Falkenberg's objection to this approach?

A. Mr. Falkenberg argues for exclusive use of the median, or 50 percent exceedance level. He claims that the Company's current approach inaccurately assumes the same water conditions will occur on all river systems throughout the test period. He also claims that the Company agreed to use of the median case in the most recent Oregon TAM order.

Q. Please respond.

A. The Company averages the results of the three different GRID studies using a range of exceedance levels to normalize the outcome of forecasted hydro generation by capturing the different water conditions that can occur on any river system at any time of year. The assumptions this approach makes around the correlation of river systems are appropriate, given that there is some level of correlation and the purpose of the modeling is to normalized hydro conditions.

Q. Did the Company agree to sole use of the median case in the most recent Oregon TAM case?

A. No. Mr. Falkenberg argued in that case that the Company should use the "mean" instead of the "median" in this modeling. The Company opposed this position and argued for continued use of a median case. The Company did not agree, however, to cease reliance on other exceedance levels in its hydro modeling.

Q. Did the Oregon Commission ultimately reject Mr. Falkenberg's claim that the Company's hydro modeling was biased in the Company's favor?

A. Yes. The Oregon Commission found no evidence that the "model tends to skew the result in some manner that is more favorable to the Company."

Q. Do you think Mr. Falkenberg's proposed approach to hydro modeling should be adopted?

A. No. The Company's approach to hydro modeling fairly approximates the likelihood of wet, dry and normal water years in setting normalized NPC. In any event, Mr. Falkenberg's adjustment would likely have a negligible impact on revenue requirement in this case because his adjustment would increase hydro availability, decrease the dollar per MWh charge for hydro and decrease the embedded cost differential benefit to Utah.

CCS 4.16 (Hydro Reserve Input Parameter)

Q. Please describe this proposed adjustment.

A. Mr. Falkenberg appears to object to the use of the Company's hydro units to provide regulating margin when the Company's load is most volatile. Elimination of this reserve produces a decrease in modeled NPC of $1.2 million total company.

Q. What is regulating margin?

A. Regulating margin is a requirement similar to spinning reserves requiring quick adjustments to Company's generation level to respond to load and resource imbalances within a short period of time. The system load is modeled in GRID on an hourly basis. The regulating margin requirement is to capture intra-hour fluctuations of the system load. Hydro resources can be ramped quickly to respond to these requirements.

Q. What is Mr. Falkenberg's objection?

A. His objection appears to relate to the Company's determination of the value of this parameter.

Q. Please respond.

A. In order for a model to simulate real operations, assumptions have to be made due to the fact that few models, if any, can operate encompassing all the necessary constraints in the real world. The assumptions can be made based on various studies or based on years of experience of the people who have operated the system. The value of the hydro reserve input parameter is one of those parameters that is determined based on experience in real operations. The Company has always followed the practice of using its hydro units to cover regulating margin. There is no change in this case from the Company's historic practice of using hydro capacity for load following. For these reasons, the Commission should reject Mr. Falkenberg's adjustment.

CCS 4.20 (Duct Firing Reserve Capability)

Q. Please explain Mr. Falkenberg's proposed duct firing reserve capability adjustment.

A. Mr. Falkenberg recommends the Commission adopt his proposed interim method to combine the combined cycle and duct firing capabilities of the Currant Creek and Lake Side plants into single units for purposes of modeling in GRID. This is in contrast to the Company's approach of modeling the combined cycle and duct firing portions of the plant separately. Mr. Falkenberg's adjustment would reduce proposed NPC by $3.6 million total company.

Q. Do you agree with Mr. Falkenberg's adjustment?

A. No. It appears that when he combined the duct firing with the combined cycle, he generated reductions in net power costs by reducing the heat rate for the duct firing down to a level based on the heat rate equation used for the combined cycle plant. As a result, he overstated the efficiency of the duct firing and understated net power costs.

Q. Are there other concerns with his proposed interim method?

A. Yes. GRID is not capable of reasonably modeling a combined cycle plant with duct firing as a single unit, because the heat rate curve is developed using a polynomial heat rate equation which is unable to jump up to a higher heat rate when the duct firing is started. Also, GRID would not be able to capture the start up time required for using duct firing. It is for these reasons the Company has modeled Currant Creek and Lake Side with the duct firing separate from the combined cycle.

Q. Has Mr. Falkenberg made any other recommendations regarding duct firing?

A. Yes. He has recommended that the Commission require the Company to develop a modeling enhancement for GRID that allows proper modeling of all modes of operation for combined cycle generators before the next general rate case is filed.

Q. Do you agree with this recommendation?

A. No. It is not reasonable to delay a general rate case based on Mr. Falkenberg's concerns over the modeling of duct firing. The Commission should reject this recommendation.

CCS 4.22 (Heat Rate Modeling Adjustment) and CCS 4.23 (Minimum Loading Deration)

Q. Please explain Mr. Falkenberg's proposed heat rate modeling and minimum loading deration adjustments.

A. Mr. Falkenberg argues that the Company's heat rate curves and unit minimum capacities should be adjusted as a result of the use of the deration method to model forced outages. The proposed adjustments result in a reduction to net power costs of $3.6 million and $1.1 million total company, respectively.

Q. Do you agree with these adjustments?

A. No. The Company has been using the deration method to model forced outages for over 25 years without the proposed mathematical alterations to the heat rate curves and minimum unit capacities proposed by Mr. Falkenberg. If this was such a glaring error in the methodology, it seems that one of the Company's commissions would have raised an objection to it by now.

Q. Are the examples in Mr. Falkenberg's Exhibit CCS 4.16 realistic?

A. No. Mr. Falkenberg's attempt to support his proposed heat rate adjustment is based on the flawed assumption that forced outages result in plants being either on or off. In reality, plant outages result in units running at all different levels depending on the nature of the outage. Mr. Falkenberg's adjustment does not recognize that many forced outages are partial forced outages. He assumes that each plant runs at its most efficient heat rate during partial forced outage which is simply impossible. When asked to explain the content of this exhibit in a data request from the Company, Mr. Falkenberg responded by saying that "tracing through the calculations shown on this exhibit will enable the Company to understand this analysis."

Q. Is Mr. Falkenberg's proposed reduction to the unit minimum capacity reasonable?

A. No. The plant minimum is the plant minimum. Adjusting this makes no sense at all and appears to simply be a mathematical ploy to lower net power costs in the **model.**

Q. What is your recommendation regarding the heat rate curve modeling and minimum loading deration adjustments proposed by Mr. Falkenberg?

A. The Commission should reject these unfounded proposed adjustments. The adjustments are based on flawed analysis and are inconsistent with the application of the deration method the Company has used and this Commission has employed for many years.

CCS 4.24 (Station Service)

Q. Please explain Mr. Falkenberg's proposed station service adjustment.

A. Mr. Falkenberg argues that the Company's station service costs should be removed from the case and modeled in the future in generation plan heat rates. The proposed adjustment would reduce proposed net power costs by $1.5 million total company.

Q. What station service charges are covered by Mr. Falkenberg's adjustment?

A. Costs to serve the energy needs of a plant when the plant is off-line and cannot self-supply.

Q. Do you agree with the proposed adjustment?

A. No. Mr. Falkenberg does not challenge the existence or reasonableness of these costs; he just proposes that they be embedded in a different calculation. But the Company's current modeling of loads and resources does not capture station service when a unit is offline and station service is a load on the Company's system. Therefore, a separate charge for station service charge is appropriate.

Q. How does the Company model the load associated with station service when thermal units are offline?

A. Station service is modeled as an addition to retail load to capture the associated system cost. The information is captured and provided by PacifiCorp Energy's Compliance Reporting Department.

Q. Why isn't station service captured in the load and resource modeling?

A. Load is equal to net generation plus interchange. Net generation only captures station service when the units are running, thereby excluding station service when the units are not running. To be consistent, heat rates are also calculated based on when the thermal units are running and do not include the impact of station service when the units are not running. Unless a separate load adjustment is made as proposed by the Company, the costs of that station service will not be recovered by the Company and there will not be a proper match between costs and benefits.

Q. Did the Oregon Commission agree to the inclusion of station service costs last year?

A. Yes. The Commission approved the inclusion of station service costs on the basis that these were real costs that would be incurred during the forecast period.

UAE 1.1 (Currant Creek Minimum Generation)

Q. Please describe the adjustment to planned plant outages proposed by Mr. Higgins.

A. Mr. Higgins reduces the minimum generation of Currant Creek to reflect operation in a one-by-one configuration while leaving all other parameters consistent with a two-by-one configuration. He contends this is how the unit was described in the Currant Creek certificate proceeding and this flexibility should be modeled into GRID. The proposed adjustment reduces modeled NPC $4.58 million total company.

Q. Do you agree with this adjustment?

A. No. Mr. Higgins has combined the minimum generation level of a one-by-one plant with the heat rate, size, capability for duct firing and other parameters that are only available with a two-by-one configuration. The reduction in net power costs shown by Mr. Higgins arises from the mismatched configuration of the Currant Creek plant. While I agree with Mr. Higgins that the Currant Creek unit has the operational capability to operate in the one-by-one mode, the most cost effective mode of operating the unit is the two-by-one mode.

The one-by-one units have a higher heat rate than the unit running in the combined cycle mode. GRID does not have the capability of simultaneously running the units in a one-by-one mode and then switching back to a two-by-one mode. This is not unique to GRID as the Planning and Risk (PaR) model from Ventex, which is used by the Company for integrated resource planning, works similarly to GRID. The Company has to choose between a two-by-one and one-by-one configuration when setting up its models. The Company has chosen to model Currant Creek as a two-by-one facility in both GRID and PaR.

Q. Does the commitment logic workaround proposed by the Company address Mr. Higgins' concern?

A. Yes. The Company found that after implementing the commitment logic workaround, the impact reduced Mr. Higgins' proposed adjustment by 80 percent to approximately $0.9 million**.**

Q. What is your recommendation regarding this adjustment?

A. I recommend that the Commission reject this adjustment and continue to allow the units to be modeled in their lowest cost mode, which is two-by-one combined cycle mode.

Conclusion

Q. Mr. Duvall, please summarize your analysis.

A. In my testimony, I have demonstrated the reasonableness of the Company's revised $1.044 billion system NPC using alternative approaches. The Commission can determine and validate this system NPC recommendation: (1) by using the DPU's recommendation; (2) based upon the revised Company NPC study incorporating all adjustments, both those that increase and decrease NPC; or (3) from projections based upon the Company's most recent actual NPC.,

In contrast, all of this evidence demonstrates that the Commission should view the system NPC recommendation from Mr. Falkenberg of $986 million as an outlier, a number to be rejected because it is fundamentally out-of-step with the totality of the evidence in this case and the regulatory prudence standard.

Q. What do you conclude and recommend in this case?

A. I conclude that the Company's revised system NPC of $1.044 billion is just and reasonable and should be approved by this Commission. Based upon a historical review and current actual data, it seems clear that the recommended system NPC of $1.044 billion is a conservative estimate of what it will cost the Company to serve its growing base of customers in the state of Utah.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.